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Item 1a
Agenda 12/9/87

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Investigation on the Commission's motion into implementing a rate design for unbundled gas utility services consistent with policies adopted in Decision 86-03-057.	I.86-06-005 (Filed June 5, 1986)
And Related Matters.	R.86-06-006 (Filed June 5, 1986) Application 87-01-033 (Filed January 20, 1987) Application 87-01-037 (Filed January 27, 1987) Application 87-04-040 (Filed April 20, 1987)

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OPINION

The issues presented for resolution in this proceeding are numerous and complex. An extensive record has been developed. Over 30 days of hearings were held before Administrative Law Judge Kenneth Henderson. Although most of the hearings were held in San Francisco, hearings were also conducted within the territory of each of the three respondent utilities. During the hearing phase of this proceeding over 4,500 transcript pages were compiled; over 150 exhibits were received into evidence; and, in addition to the 19 parties that presented witnesses, a number of other parties participated actively throughout the proceedings. Finally, briefs were submitted by over 30 parties.

The ALJ's proposed decision was served on November 5, 1987. Following the ALJ's proposed decision comments and/or replies to comments on the ALJ's proposed decision were filed by 22 parties. In addition, we received a very large volume of correspondence primarily concerning the proposed decision's resolution of the "small cogeneration" issue. We have carefully reviewed these comments/replies but will not summarize them in this order. To the extent that we have relied on the comments of a party in changing the ALJ's proposed decision, we have attempted to provide the proper attribution in the body of this order.

I. Background/History

Today's decision is intended to implement in rates the major policy decisions which we made in December, 1986, in Decisions (D.) 86-12-009 and D.86-12-010. To assist the reader in understanding the issues which we decide below, we will review the foundations of these orders -- especially the rate design principles -- and the significant changes which we made in our program in a series of modifying decisions last spring. We will also discuss the types of issues which this order will not address.

The first principle of the conceptual approach to rate design which we adopted in D.86-12-009 is that "economic efficiency dictates that rates be based on marginal cost, not embedded cost" (p. 13). We examined a number of approaches to a marginal cost-based rate design, and recognized that all the methods presented either conceptual or implementation problems. The approach we finally adopted was intended to preserve, to the greatest extent possible given the state of the art, the benefits of marginal cost pricing. The utilities were allowed substantial flexibility to negotiate transmission rates with noncore customers--those users with viable options to utility service. We accepted the DRA's replacement cost method, which the DRA advanced as a proxy for long-run marginal costs, as the ceiling for the range of rate flexibility. The floor was set at the short-term variable cost of transporting gas. Within this broad range, we expected that the utilities would be able to negotiate rates tailored to the individual demand elasticity of particular customers. In this way, we hoped to approximate the efficiency benefits of marginal cost pricing. In exchange for the broad rate flexibility which we have granted the utilities, we have placed them at risk for the recovery of the non-gas costs allocated to the noncore market.

In this case, we have heard many arguments about whether a particular proposal is consistent with our alleged movement toward a "cost-based" rate design. The term "cost-based" is unfortunately vague, as it conveys no information about what sort of costs (marginal? embedded? replacement?) are the basis. We stated in D.86-12-009, and have since reiterated, our intent to base our rate design on marginal cost principles. In D.86-12-009 we used embedded costs only for the initial step of allocating non-gas costs between the core and noncore markets. In the absence of a viable marginal cost method for performing this allocation, we decided to use the relatively simple, understandable embedded cost method. We chose to use relatively "flat" factors in making this allocation, reflecting our belief that all customers should contribute to the costs of the excess capacity in today's system, until the excess is reduced and the current period of transition to an unbundled rate structure is complete. We emphasized that our use of embedded costs will be temporary, until the application of marginal cost principles to natural gas rate design is further developed. Moreover, the rate flexibility in the new rate design will allow some of the efficiency benefits of marginal cost pricing to be realized.

We received numerous requests for rehearing and/or modification of this rate design framework. In D.87-03-044 and D.87-05-046 we made two important modifications to this structure. In response to petitions for rehearing of D.86-12-009 filed by the California Industrial Group (CIG) and the City of Pasadena, D.87-03-044 changed the ceiling of the band of rate flexibility, which will be the "default" rate in the absence of a negotiated rate. D.86-12-009 established the default rate based on replacement costs, without scaling those costs back to meet the revenue requirement; D.87-03-044 lowered the default rate to the level of embedded costs, which by definition are scaled to the revenue requirement. This change resulted from our concerns that a default rate which was not scaled to collect just the revenue requirement might not be just and reasonable, and that a high default rate might encourage the utilities to discriminate unduly among noncore customers. The utilities and TURN immediately asked us to reconsider D.87-03-044. The utilities argued that default rates set at the embedded cost level would not provide them with a reasonable opportunity to recover their revenue requirement; TURN agreed, and expressed the fear that if the utilities could not maintain noncore throughput, the Commission would reallocate costs to core customers. We addressed these concerns in D.87-05-046, by making a series of "fine tuning" adjustments to our program, addressing those situations in which it is clear that present contractual rates or economic circumstances dictate that the utility cannot recover the embedded cost of service from certain customers. These adjustments included:

1. Spreading equally among all other customers the shortfall below embedded costs from existing long-term transportation contracts with non-EOR customers.

2. Allocating to the UEG default rate the shortfall resulting from the statutory requirement that industrial customers with cogeneration equipment receive rate parity with the UEG class.

3. Removing EOR revenues from the cost allocation process, in recognition that the rate to this class is constrained by their bypass alternatives.

4. Reducing the risk to SoCal Gas that it may not recover the non-gas costs allocated to the large UEG class, by including in the UEG volumetric rate only 25% of SoCal's return on equity and taxes allocated to the UEG class.

We emphasized that these adjustments will allow the utilities to start off our new regulatory program without the prospect of a "built-in" revenue deficiency, yet they stop short of measures which would virtually guarantee revenue recovery. We noted that the utilities have a number of options if competitive pressures force them to discount their transmission rates below the default rate. The first is to pressure the upstream pipelines and producers to absorb a portion of the discount necessary to meet the market. A second is for the utilities to cut costs, which would benefit all ratepayers. Finally, the utilities have the safety net of the NRSA mechanism which the Commission approved in D.86-12-010. Our conclusion was that the modified program fully meets our legal obligation to provide the utilities with a reasonable opportunity to earn their authorized rate of return.

A. Reserved Issues

The purpose of this proceeding has been to produce rates which implement this new rate design program. There are a number of aspects of our December, 1986, gas policy decisions which are not being implemented or reviewed in this case. However, at times these issues have surfaced in this proceeding, because they somehow have an impact on, or are affected by, the ratesetting process. We will review these issues briefly here, in order to make clear at the outset the bounds we will place on our consideration of what has been presented to us in this proceeding, and to indicate where we will address those matters that fall outside the rate design focus of this case.

1. Procurement Issues

D.86-12-010 contained an extensive discussion of our policies on the utilities' gas procurement activities under the new regulatory structure, in both the core and noncore markets. In this case our consideration of gas procurement was limited to constructing core and noncore portfolios based upon the utilities' current purchasing policies and mix of contracts, and to determining what portion of current gas costs should be treated as transition costs for ratemaking purposes. The presiding ALJ correctly excluded testimony directed at revising current sequencing guidelines. We instituted I.87-03-036 to examine procurement issues which remain following D.86-12-010, and recently issued D.87-10-043 in that inquiry. D.87-10-043 asks for comments on a broad range of core and noncore procurement issues, including the sequencing concerns which parties tried to advance in this case. I.87-03-036 will be the appropriate vehicle for the further consideration of the procurement issues which our new regulatory framework raises.

2. System Reliability Issues

We recognize that issues remain regarding how the utilities will operate their systems to provide reliable service under the new regulatory regime. For example, an issue which Hadson raised in this case is whether the utilities will use their storage capacity to provide core-elect customers with more reliable service than noncore transport-only users. The possibility that the utilities might relinquish some of their firm interstate pipeline capacity was also raised in this proceeding. We have decided to consider such issues in I.87-03-036, due to their close connection with other procurement issues. D.87-10-043 set hearings on storage issues as the first order of business in I.87-03-036.

B. Basic Policies

We want to stress up front that the intent of this case has been to implement rates based upon the policies decided in D.86-12-009, D.86-12-010, and subsequent modifying orders. Throughout this proceeding we have received a steady stream of petitions for modification of the basic policies set forth in these orders, and a number of parties have proposed changes in our basic program in the course of their "implementation" testimony. As an aid to the efficient discussion and disposal of many of these requests, we will indicate here those policies which we strongly feel are properly beyond the scope of this implementation proceeding.

1. The Interpretation of the Baseline Statute

In recent years, we have seen extensive litigation in gas rate design cases of the interpretation of the baseline statute (PU Code Section 739). AB 2764 required the Commission to study the effectiveness of Section 739 and to report to the Legislature our findings, conclusions, and recommendations for the baseline program. That report supported the goals of the program, as well as the current inverted two-tier residential rate design, but recommended that the Legislature grant the Commission greater flexibility in setting the baseline rate for the first tier. We also asked for the authority to implement an energy assistance program targeted to low-income ratepayers. With the ball now clearly in the Legislature's court, this order will not break new ground in interpreting the baseline statute.

2. <u>Allocation Factors</u>

D.86-12-009 adopted allocation factors to divide nongas costs among the core, noncore, and wholesale markets. We explicitly chose relatively "flat" factors which tend to spread these costs more evenly over all markets. These factors recognize that the current system was built to serve all customer classes, and that all users should contribute to paying for the current excess capacity in the system. We have been asked on several occasions since D.86-12-009 to revise those allocation factors, and in both D.87-03-044 and D.87-05-046 we have firmly refused. We reiterate today our intention not to revisit this issue until, as stated in D.86-12-009, such time as the present excess capacity is reduced.

3. <u>Cost-based rates</u>

Throughout this proceeding we have emphasized our commitment to cost-based gas rates, believing that rates based on cost provide customers the best possible signals regarding how much gas to use and when to use it. This commitment to "cost-based" rates, however, does not settle the question. We have had to examine the costs themselves, concluding that although we prefer marginal costs, embedded costs are sufficient to use in implementing the new industry structure while we await completion of marginal cost studies. We have considered the methods of allocating these costs, concluding that some costs are best allocated by annual throughput, some by peak season throughput, and so on. 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.

In establishing a default rate design, and most particularly in deciding which cost components to assign to which rate design component, we have continued our commitment to cost-based rates. Although some would have us consider demand charges the proper place for all "fixed" costs and the volumetric rate the proper place for all "variable" costs, we realize that this formulation is too simplistic. We have learned in our electric rate designs the economic principle of long-run marginal cost, which considers all costs variable, differing only in the time it takes them to vary. What are often called fixed costs are in fact just variable costs that happen to vary over long periods of time. If no throughput (a "variable" item) existed, we would have no need for transmission facilities (a "fixed" item); in fact, the size of a transmission system depends finally on the amount of throughput demanded.

We choose not to limit our gas rate design to a straitened definition of which costs are fixed and which are not; instead, we adopt a rate design based on a mix of short- and long-term cost incurrence, assigning some "fixed" costs to the volumetric rate and recognizing that, ultimately, all costs depend somewhat on the efficiency of the gas utilities' operations and management. This latter understanding has led us to consider risk management strategies, for instance, as an appropriate part of our cost-based rate design.

We have also wrestled with the complicated question of assigning costs to customers who, though not perhaps historically causing the incurrence of a cost, nevertheless benefit from the existence of what the cost buys. It has been argued -- for example, in the comments of Transwestern -- that assigning costs on the basis of benefit represents a departure from cost-of-service, and a move toward value-of-service, ratemaking. We find this argument incorrect.

The value of a product is what customers are willing to pay for it; in the case of natural gas for non-core customers, this is presumably no more than the price of oil. Value-of-service ratemaking would therefore price gas equal to the price of oil, as we have done in the past. As used in this proceeding, the benefit something (e.g., storage) brings to a customer class is the part it plays in the availability to that class of an ultimate product -- natural gas. For instance, the existance of gas storage systems allows non-core customers the possibility of gas service during peak seasons. Value-of-service ratemaking would ignore the utility's costs and set the peak season gas rate at whatever the oil price happened to be. Cost-of-service ratemaking measures the costs of storage and allocates them to each class according to a wide variety of criteria, including the benefits each class receives from storage. The fact that we find the concept of benefits received useful in cost allocation in no way contradicts our commitment to cost-based rates.

II. Major Issues

Certain major issues are of such importance that we think it best to bring their discussion and resolution to the forefront of this decision. Combined with our discussion above, which indicated that certain issues will not be addressed in this proceeding, resolution of these major issues of general policy will simplify the discussion of the more detailed questions that will follow. These major issues are listed below in the order that they will be discussed:

1. Transition Costs
2. Industrial Sales Forecasting

3. Priority Charge Mechanism
4. Core/Noncore Customer Definition

A. Transition Costs

1. The Concept

D. 86-12-009 and D. 86-12-010 discussed the concept of transition costs, without attempting to quantify them or to define them more specifically than providing several examples of the type of cost that we considered to fit the concept. We stated the essential idea of transition costs on page 23 of D. 86-12-009:

> The basic concept is founded upon our recognition that there are certain costs that result from the past structure and practices of the gas industry, which are today in excess of a reasonable level, given today's gas market and the new, still evolving industry structure.

These costs date from the era when the utilities bought gas and built their systems with the obligation to serve all types of customers. The purpose of identifying these costs now is to enable them to be shared equally among all current gas users. If the existence of these costs means that all customers cannot enter the newly competitive gas market with a "clean slate", at a minimum, out of a sense of fundamental fairness, we can ensure that everyone carries a slate that is equally dirty.

The December 1986 orders noted that one class of transition costs could be associated with the excess fixed costs of the utilities' intrastate transmission systems and their interstate pipeline demand rights. We chose to reflect such "fixed cost" transition costs in our choice of relatively "flat" allocation factors. The other class of transition costs which we discussed are related to gas commodity purchasing practices. As examples of "commodity-related" transition costs we cited the possible excess gas commodity costs in current long-term supply contracts, producer take-or-pay costs passed through the pipelines to California utilities, and premiums paid to meet minimum operating requirements. The issue presented in this case is to take the utilities' current mixes of suppliers, and to calculate the current amount of "commodity-related" transition costs.

The parties presented calculations which generally followed one of two predominant views of the transition cost concept. One common view was the stringent perspective of SoCal Gas, supported and/or expanded upon by most of the producer, pipeline, and industrial customer representatives that participated in this discussion. PG&E, TURN, and DRA advanced calculations based upon a broader view of transition costs. The Canadian Producer Group was perhaps the only party to suggest a view somewhere between the two major positions.

The more stringent definition of transition costs, advanced by SoCal Gas and others, would limit them to costs incurred:

1. During the present period of change in regulation,

2. Due to specific regulatory action during the transition to the new regulatory environment, and

3. Not attributable to a particular class of customers.

SoCal argues that cost items which do not fit any one of these criteria should not be treated as transition costs. Thus, costs which result from shifts in the marketplace, rather than from specific regulatory actions, would not be considered transition costs. From this perspective, SoCal would treat as transition costs only limited producer take-or-pay costs (of which there are none at this time for SoCal) and a portion of the settlement costs pertaining to the El Paso liquids problem. Other parties -- for example, Shell Canada -- have calculated transition costs under this definition to be non-existent, and have urged us not to give transition cost treatment to commodity costs which the utilities could avoid by not purchasing a particular supply.

The broader definition, favored by PG&E, TURN, and the DRA, holds that transition costs are those costs:

1. That are related to the past practices and structure of the industry which are in excess of a reasonable level, and

2. That should not be borne by a single class of ratepayers.

The emphasis in this broader definition is on the current reasonableness of these costs, rather than, as in the SoCal approach, on the past reasons for their incurrence.

The brief of the Canadian Producer Group contained a third concept of transition costs. This concept differs from the SoCal position in that it does not require a causative relationship between cost incurrence, on the one hand, and a past regulatory action, on the other. Specifically, CPG states that:

> "The fundamental issue in allocating prudently incurred costs among California's ratepayers ought to be nothing more than the question of whether the costs were incurred on behalf of all ratepayers, with a reasonable expectation that they would be recovered from all ratepayers."

Thus, the residual costs of past gas purchase arrangements which were undertaken for the benefit of all ratepayers, and were intended to be recovered from all ratepayers, should now be recovered from all ratepayers. TURN frames this "equitable" approach to transition costs in another way, one that looks forward to finding a fair basis for all gas consumers to begin a new era in the gas industry:

> "In its simplest terms, the question here is merely one of cost allocation--in the process of dividing up the existing gas supplies into two separate portfolios (the key "change in regulation" that has occurred), who should pay for the high-cost

> contracts and commitments that <u>neither</u> portfolio would reasonably purchase today if given the choice?"

We believe that the "equitable" concept of transition costs expressed in the two quotes above best captures the intent which the Commission expressed in the December 1986 decisions. We disagree with SoCal and its supporters that a cost item must be directly linked to a specific regulatory action in order to qualify as a transition cost. Nothing in the December 1986 decisions indicates that we expected such a linkage, and we concur with the testimony of Transwestern's witness Smith concerning the impossibility of separating the impact of market forces from the effects of regulatory change:

> It is all but impossible to quantify those costs that were caused by regulatory changes versus those changes in cost simply occasioned by normal market forces. There does not appear to be any rationale means available for isolating the effects of regulatory change and market change or to compare gas costs today with what they would have been in the abscence of regulatory changes.

For example, the regulatory changes in California which have culminated in this decision both responded to market forces (gas-to-oil competition) and have released new market forces (gas-to-gas competition), resulting in a web of influences which seems futile to attempt to unravel.

Rather than attempting to untangle the past, we prefer to adopt a more forward-looking approach to transition costs. We concur with the CPG that in exhuming the past, our inquiry should extend no further than whether a particular cost was incurred for the benefit of all ratepayers, and was meant to be recovered from all ratepayers. Then in calculating and allocating the transition costs to be born by today's ratepayers, we will use the equity principle which TURN states simply in the above quote. Our goal is to start all ratepayers off on an even footing in our new regulatory framework, with all customers carrying an equal load of the baggage of the past.

Based on this discussion, we can state a simple definition of transition costs. A cost item will be considered a transition cost if it resulted from a gas purchase contract, tariff, or arrangement which:

1. Took effect before the division of the supply portfolio in the December 3, 1986, decisions;

2. Was initiated for the benefit of all ratepayers;

3. Was intended to be recouped from all ratepayers; and

4. Now results in costs in excess of a currently reasonable level.

2. <u>The Calculation</u>

With the above definition in mind, we may now develop a method of calculating transition costs and then consider specific cost items that were raised during the course of this proceeding. In doing so, we are mindful of the legitimate concerns of many parties that our definition of transition costs could result in an excessive and, worse, unpredictable burden of transition costs upon the noncore market and the utilities that must compete to serve it. Indeed, it appears that such worries were the prime motivation that led many parties to support SoCal's stringent concept of transition costs. Such a concern motivated CMA to propose a cap on the allocation of transition costs to the noncore -- either as a restriction on their size or a limit on the time that they can be incurred, billed, or paid. We cannot completely assuage these fears, given the prospect of hundreds of millions of dollars in producer take-or-pay costs which might reach California utilities, but we will certainly consider the need for stability and predictability in our review of the possible transition cost items which are before us at this time.

The showings of the parties presented two general methods of calculating transition costs. TURN characterized these methods as (1) "bottoms-up" and (2) "tops-down". The bottoms-up method involves the comparison of actual gas costs with a "benchmark" price -- any costs above the benchmark are transition costs. This method was followed by both TURN and PG&E. The chief attribute of this method is its simplicity. Its major shortcoming is the difficulty in setting a benchmark price.

The tops-down method relies on looking at the gas portfolio, considering every detail of gas cost, then making a judgement as to whether or not a particular detail fits the definition of transition costs. The main virtue of this approach is that the setting of a benchmark price can be avoided for many, but not all, of the cost items. The main drawback is the complexity of reviewing numerous cost items.

a. Bottoms-up

The key step in the bottoms-up approach is the setting of the benchmark price. Both PG&E and TURN argue that the commodity price of PGT's Canadian supplies represents the proper benchmark for PG&E. This is a single large supply whose price is redetermined periodically in accordance with market conditions. The current price is $1.8261 per MMBtu. There is no directly comparable source of supply for SoCal. TURN reviewed a "market basket" of SoCal's long-term supplies and concluded that the benchmark for SoCal should be $1.99 per MMBtu. The ALJ's draft order chooses the first tier of SoCal's Pan Alberta gas, also at $1.99 per MMBtu, on the grounds that this supply comes the closest to the characteristics of PG&E's PGT supply.

Having chosen the benchmark, the next question is whether to apply the benchmark price to each individual source of supply in the core portfolio or to the entire core portfolio WACOG. TURN and PG&E would apply the benchmark to individual supply sources priced above the benchmark, disregarding in the calculation supplies cheaper than the benchmark. The ALJ argues that we should apply the benchmark to the entire portfolio WACOG, because the bottoms-up concept establishes a benchmark for a portfolio under "clean slate" conditions and the price of this clean slate is represented by the benchmark price. This approach implicitly recognizes the existence of "negative transition costs" i.e., that some individual sources of supply will be below the benchmark and will carry negative transition costs. It thus produces a lower level of excess gas costs.

Numerous parties criticized the bottoms-up approach. The critique focused on the problems inherent in the choice of a benchmark price which accurately represents a reasonable price level for long-term supplies in today's market. Many commenters noted that the ALJ chose two Canadian supplies as benchmarks, supplies whose commodity price is based upon a different rate design than the commodity prices of the domestic pipelines. Thus, the use of these benchmarks would result in an unfair "apples-to-oranges" comparison among gas supplies. In addition, parties noted that, at any particular time, gas prices can be expected to vary above or below a benchmark for reasons that do not necessarily mean that the underlying costs of particular supplies are either excessively expensive or cheap. For example, El Paso notes that the commodity-only price of its gas at the California border, after removing fixed costs and balancing accounts, is $1.72 per MMBtu, below both of the benchmarks. A related problem is the apparent volatility of the "bottoms-up" calculation. The ALJ's draft order calculates excess gas costs of $14.8 million for SoCal. Using the same methodology, with updated gas costs to reflect the latest pipeline filings, excess gas costs would exceed $90 million. The following table shows these calculations, including the other transition cost items (GEDA and the El Paso liquids settlement) adopted by the ALJ.

TRANSITION COSTS -- SOCAL GAS

(Bottoms-up Approach)

SoCal (ALJ draft)

	MDTherms	$/Dth	M$
Core Cost of Gas	468,921	2.0243	949,267
Benchmark	468,921	1.9928	934,466
Cost of Gas Transition Costs			14,801
GEDA			18,421
El Paso Liquids			72,333
Total Transition Costs			105,555

SoCal (with updated gas costs)

	MDTherms	$/Dth	M$
Core Cost of Gas	470,166	2.099	986,906
Benchmark	470,166	1.906	896,190
Cost of Gas Transition Costs			90,716
GEDA			18,421
El Paso Liquids			72,333
Total Transition Costs			181,470

These problems with the benchmark price convince us that we cannot adopt a "bottoms-up" approach to transition costs at this time. The recent changes in gas costs were not particularly dramatic, yet the huge resulting increase in the ALJ's calculation of excess gas costs would have a dramatic effect on our rate design. Responding to the valid concern of noncore customers that they not be burdened with transition costs that are unpredictable and unstable, we cannot adopt a method that is subject to such evident volatility. We are also sympathetic to the "apples-to-oranges" criticism of attempting to compare gas supplies with disparate rate designs. However, we will not preclude the use of a "bottoms-up" method in the future: as the competitive gas procurement market continues to develop, it may be possible to resolve the problems we have identified, and to identify a benchmark gas price that accurately reflects the current market.

Therefore, for quantifying transition costs we will use the item-by-item review of a "tops-down" approach.

b. Tops-Down Approach

The DRA quantified transition costs using a tops-down approach. The DRA described its method as follows:

> "This methodology starts with the long term supplies assigned to the core portfolio and analyzes the various cost components of each supply. Those elements that meet the definitional test for a transition cost such as excess costs associated with minimum operating requirements (MOR) are then removed. The remaining long term supply costs are then used in constructing the core portfolio WACOG"

The DRA identified a number of cost items that meet its definition of transition costs. Although we do not concur completely with the DRA's transition cost definition or its analysis of the transition cost items which it identified, we will follow the DRA's list in our discussion of the adopted transition cost caculation. The DRA's list contains:

1. El Paso Liquids Settlement.
2. Directly Billed Costs.
3. FERC Acct. 191 costs.
4. Take-or-pay costs.
5. GEDA costs.
6. Demand charge component of gas withdrawn from storage.

7. Excess gas costs associated with Minimum Operating Requirements (MORs).

8. Excess gas costs associated with Minimum Purchase Obligations (MPOs).

In addition to these particular items, TURN has proposed that the costs of the abandoned LNG project also be considered a transition cost.

El Paso Liquids

FERC established a revenue requirement for El Paso in its last general rate case that contained a revenue requirement offset which consisted of revenues earned from the production of "liquids" on its system. However, the precipitous drop in petroleum prices which followed the FERC decision reduced El Paso's liquids revenues substantially below the forecast. Under traditional ratemaking rules, the undercollection was recorded in a balancing account (Account 191). Recently FERC has approved a mechanism to recover this undercollection which involves the direct billing to El Paso's customers for the amounts both presently undercollected and also for the amounts forecasted to be undercollected until the next general rate case. This cost item clearly is associated with a source of supply that was taken for the benefit of all customers, and whose costs were intended to be recovered from all customers.

The CPG questions whether the forecasted portion of the settlement should be spread to noncore customers, arguing that at the time the settlement was negotiated, all parties were on notice that noncore customers would not have to bear the costs of new long-term supply arrangements. Essentially, CPG maintains that the prospective portion of the settlement dates from after the effective date of the division of the supply portfolio. We disagree, because the crucial part of our definition is when the obligation was incurred. The obligation to purchase gas from El Paso under rates assuming a high level of liquids revenues was incurred when we acquiesced in El Paso's last general rate case settlement, and will not be extinguished until the pipeline's general rates are revised in its upcoming rate case. All customers should share in the full cost of settling this obligation.

SoCal attempted to establish that only 25% of the liquids problem was caused by the growth of gas transportation; SoCal argued that the remainder was due to the fall in energy prices. As we have discussed above, we are skeptical of such attempts to separate the impact of regulatory changes from the effect of market forces, and we did not include such a distinction in our definition of transition costs. We will not adopt SoCal's argument.

The liquids settlement will be recognized as a transition cost.

<u>Order 94/270 Costs</u>

These costs are commodity-related costs that were held in a separate account until all contested issues surrounding them could be resolved by FERC. When FERC resolved the issues, it also decided that the costs were too old to be placed in a current volumetric rate and instead provided for their direct billing. These costs clearly fit our definition and will be considered transition costs.

<u>Account 191</u>

Other than the Order 94/270 costs, there are presently no costs in this account that are likely to be direct billed. This account is essentially a balancing account, but occasionally other items are placed it. We cannot agree with the staff that all costs that are directly billed should be treated as transition costs. Rather, we agree with the majority of other parties that cost items to be included in Account 191 should be judged individually.

<u>Take-or-Pay</u>

Take-or-pay costs are those costs which pipelines pay to their producer-suppliers under contracts which require the pipeline to take a given amount of gas or prepay the costs of such gas if it is not taken. In practice, pipelines frequently have taken less gas than called for in their contracts, primarily due to displacement of pipeline sales by transportation. As a consequence pipelines must either pay prepayments to the producers and attempt to make up the takes of gas at a later time, or more likely, reach a negotiated settlement with the producer to extinguish the take-or-pay liability for a payment which is some fraction of the claimed liability under the contract. In addition, such costs may also be incurred to reform the take-or-pay or price provisions of the pipeline's contract. These costs are referred to as buy-out or buy-down costs.

We view take-or-pay buy-out and buy-down costs related to pipeline purchases over the last few years as classic transition costs. They result from gas purchase contracts which signed before our division of the utilities' gas portfolios. They are associated with sources of gas that were taken for the benefit of all customers. In addition, such costs would clearly have been recovered from all customers prior to the restructuring of the gas industry which supplies California and the advent of open access transportation. Finally, take-or-pay costs have the potential to produce gas costs which greatly exceed a reasonable level in today's market.

The only take-or-pay costs to be given transition cost treatment at this time are those associated with PG&E's Canadian and Rocky Mountain supplies. We will discuss the recovery of take-or-pay transition costs in greater detail below.

<u>GEDA Costs</u>

The Gas Exploration and Development Adjustment program was initiated to develop new sources of supply for all ratepayers. The program has been terminated. At issue here are the revenue requirements for the forecast period associated with the remaining costs of the program. The revenue requirement is $50 million for PG&E and $18 million for SoCal. Once again, this cost fits within our adopted definition of transition costs and will be recognized as such.

Storage Related Transition Costs

On PG&E's system an average cost method is used to calculate the cost of storage gas. This means that all past gas purchases are reflected in the withdrawal price, and this price includes pipeline demand charges. Since our previous policy decisions provide that all customers will share in the recovery of pipeline demand charges, we need some method to isolate the demand charge component in the storage withdrawal price. PG&E proposed a method which compares the storage price of withdrawn gas to the core WACOG. The difference is considered to be a transition cost. This is a reasonable way to estimate the amount of the pipeline demand charges included in the price of storage gas.

Unlike PG&E, SoCal uses LIFO accounting for its storage costs. As a result, it is impossible to forecast similar transition costs for SoCal, because we cannot predict when SoCal might withdraw storage layers containing such costs. If SoCal does withdraw gas with demand charges attached, it should track such costs for future allocation as a storage-related transition cost.

Transition Costs Associated with MORs

This is perhaps the single most troublesome cost item to analyze. The concept is that certain minimum takes are required from supplier pipelines in order to maintain their existence in the marketplace. The DRA and others contend that all ratepayers benefit from the existence of the pipelines, and therefore all ratepayers should contribute to the cost of these minimum operating requirements.

SoCal views the issue differently. SoCal analyzes the issue by showing that the supplier pipelines perform two functions -- transportation and supply (the merchant function). SoCal argues that the MORs advanced by DRA serve the function of maintaining the merchant function, and that this benefits only the core. The pipelines continue to transport large amounts of gas even though they are selling little.

The operation of the pipelines in performing the transportation function versus the merchant function is sufficiently different to allow us to agree that there is a certain level of sales necessary to maintain the pipeline. The only pipeline that has a sales level low enough to approach the MOR is El Paso. Both PG&E and El Paso have shown that there is a MOR level for sales required to maintain the viability of the pipeline. The MOR amounts are 100 mmcfd for PG&E and 268 mmcfd for SoCal.

The costs associated with this amount of gas are not necessarily transition costs. First, to the extent that pipeline sales gas would be purchased above the MOR level, notwithstanding the existence of a MOR, there would be no transition costs. In other words, there would be transition costs only to the extent that purchases from the pipeline would otherwise be below the MOR level.

The DRA urges us to measure MOR-related transition costs using as a benchmark the system average cost of gas without fixed costs. The DRA finds this benchmark to represent a reasonable replacement cost for the MOR volumes.

There are several troubling aspects with the concept of MOR-related transition costs. The first is that they result from an operational problem that exists independent of the nature of the current gas supply arrangements, a problem that can be expected to continue even after the portfolios have been split and these arrangements have been reformed. To this extent they may not fit within our definition of transition costs, although we might view them as resulting from the service agreements between the pipelines and the California utilities which existed on the date of the portfolio split. Another problem is their volatility -- these costs would be zero if the utilities purchase slightly more than the MOR volumes, but could rise substantially if the takes then fall somewhat. We might thus provide the utilities with a perverse incentive to keep their purchases of pipeline system supplies above the MOR level. These problems convince us not to treat MOR-related costs as transition costs. However, we will note that the utilities must justify the reasonableness of any MOR-related purchases of pipeline system supplies. In today's gas market it may be possible for the utilities to meet the pipelines' MOR requirements with firm gas purchases not necessarily from the pipelines' system supplies, at prices cheaper than pipeline sales gas. We urge the utilities to consider this possibility, and ask the DRA to review their efforts in upcoming reasonableness reviews.

Minimum Purchase Obligations

The DRA explained this issue as arising from the FERC exempting certain pipeline suppliers from the elimination of minimum bills. During an earlier period the California utilities entered into gas purchase contracts that carried minimum purchase obligations (minimum bills). When the FERC substantially reduced the minimum commodity bills of most pipelines in Order No. 380, certain pipelines were exempted. In addition, there are certain non-FERC jurisdictional supplies to which Order No. 380 has not been applied. Furthermore, when the FERC completely eliminated the minimum bills of El Paso and Transwestern, these exemptions were retained. Specifically, two affiliates of SoCal, Pacific Interstate Transmission Company (PITCO) and Pacific Offshore Pipeline Company (POPCO) and an affiliate of PG&E, Pacific Gas Transmission Company (PGT) were exempted from all or a portion of the FERC's ruling in Order No. 380. In addition, substantial numbers of California producer contracts contain minimum purchase obligations, but are not subject to FERC jurisdiction. Thus, 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 note that what we consider uncompetitive is the combination of high minimum purchase obligations and higher-than-market commodity prices.

To the extent that the utility must purchase any supplies of gas from these sources at prices above a "reasonable level", the excess cost above that level can be considered an excess gas cost. Therefore, the selection of the comparison price is the next point of decision. In searching for a proxy for the price which the utility would pay for gas in an industry already completely transformed into a competitive marketplace, an infinite number of suggestions could be considered without producing a result which could confidently be called "the right one". Given the limitations of such an exercise it seems to us most practical to utilize as the standard the core portfolio's weighted average commodity cost of gas, less the supplies from which excess costs are to be extracted. Here we note that using the adopted standard the average commodity cost of gas from both PITCO and PGT is competitive with market responsive supplies and thus not excessive under our definition. 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 at this time the "bottoms-up" approach to excess gas costs.

While it is true that a number of the supplies which carry minimum purchase obligations also have significant demand charges, some of which are extremely high, we will not at this time consider such charges in the calculation of excess gas costs. This does not mean that we do not actively encourage the reduction of such charges as soon as possible.

It remains for us to address the specific comparisons between POPCO and California supplies and the core portfolio WACOG. POPCO purchases gas from its producer-supplier under two price tiers as a result of a two-year amendment to its contract. The first tier (which is the supply subject to the minimum purchase obligation) is clearly excessive (31.253 cents per therm) while the second is priced to match the spot market (17.5 cents per therm). We believe that it is most appropriate to use an average price for POPCO reflecting both tiers, because the second tier will likely always be purchased, in spite of the lack of a minimum purchase obligation, in order to lower the average cost of gas from the supplier. The use of an average price is also appropriate in order to avoid complicating any renegotiation of the price by POPCO when the two year amendment concludes.

With respect to California domestic supplies, we note that the large number and variety of contracts makes it virtually impossible to consider separately those contracts which have minimum purchase obligations or which contain tiered pricing arrangements. Thus we conclude that California production must be compared to the price standard on an average commodity cost basis. The average commodity price of all California production for each utility will be compared to the core porfolio WACOG.

Adopted Transition Costs

The table below illustrates the quantification of transition costs following our adopted approach:

ADOPTED TRANSITION COSTS

SoCal Gas

Supplier	M-therms	COG C/therm	WACOG c/therm	Transition M$
California	643,820	22.838	20.717	13,655
POPCO Hondo	98,790	24.377	20.717	3,616
Subtotal MOR/MPO				17,271
GEDA				18,421
El Paso Liquids				72,333
	TOTAL TRANSITION COSTS			108,025

PG&E

Supplier	M-therms	COG C/therm	WACOG c/therm	Transition M$
GEDA				50,000
El Paso Liquids				27,300
Take-or-Pay	Canadian			5,000
	Rocky Mountain			1,476
FERC 270/94				3,500
Storage Demand Charges				
	TOTAL TRANSITION COSTS			87,276

3. Accounting and Ratemaking Treatment

As indicated in our policy decisions (D.86-12-009 and D.86-12-010), and consistent with the "equitable" approach we have adopted today to calculating these costs, transition costs will be allocated to the core and noncore classes on an equal cents per therm basis. The one exception to this allocation method will be storage-related transition costs; because these costs are essentially "old" demand charges, they will be allocated in the same manner as pipeline demand charges, on the basis of cold year throughput.

The remaining issues regarding the accounting and ratemaking treatment of transition costs involve how much risk of cost recovery we should place on the utilities through our new rate design. This risk allocation question was a focus of controversy in this case. The DRA and all the representatives of gas consumers urged us to place a significant amount of risk on the utilities, as a strong incentive for cost reduction. The utilities warn us that our program must allow them a reasonable opportunity to recover their fixed costs and to earn their authorized return. The accounting and rate treatment of transition costs were an important part of the risk allocation controversy, because our prior orders were silent on the recovery of transition costs.

As we have already recognized, CMA and others made a strong argument for some certainty surrounding transition costs, so that a noncore customer can have a firm idea of the size of the transition costs into the future. This knowledge is crucial in order for noncore customers to make their fuel choice decisions. Thus, CMA argues for either a cap on the size of transition costs or a limit on the time that they be incurred, billed or paid. The DRA and many noncore customers oppose balancing account treatment of any transition cost item except GEDA, which has always been subject to balancing account recovery. The DRA argues that we have removed balancing account protection from the utilities' recovery of their fixed operating costs allocated to the noncore market, and that there is no reason to treat transition costs any differently from those fixed costs. The utilities have the protection of the NRSA account for the next two years, to guard against a severe underrecovery. DRA, CMA, and others also strenuously oppose allowing the utilities to discount a transition cost balancing account. Permitting such discounting could diminish cost-cutting pressure on the utilities, who would then have the option to meet competitive pressure by discounting the balancing account before discounting fixed operating costs. The DRA notes that this discounting of a balancing account, when combined with our incorporation of discounting in the sales forecast, could allow the utilities to recover twice the discounted amount. The DRA also points out that balancing account treatment removes any cost-cutting incentive that might be provided by placing transition costs in the volumetric portion of noncore rates.

The utilities ask for balancing account treatment of transition costs, for no limit on the amortization period of these costs, for the unlimited ability to discount the balalncing account, and for demand charge recovery of transition costs in noncore rates. In his draft order the ALJ adopts a flexible amortization period capped at two years, allows transition cost items to reside in a balancing account for a maximum of two years, and permits uniform discounting of the account within customer classes. He also places most transition cost items in the noncore volumetric rate. In their comments on the ALJ draft, the utilities criticize the time-limited balancing account, while the DRA and customer groups point out the potential for double recovery, the lack of real cost recovery risk, and a number of confusing inconsistencies in how the proposal would work.

What this controversy has brought home to us is the need to tailor the accounting and rate treatment to the characteristics of each particular cost item. We believe that the ALJ's proposed decision errs in placing too many disparate cost items into too large of a balancing account. Therefore, we will discuss in detail below the accounting and rate making treatment for each of our adopted transition cost items. Generally, we will not allow discounting of items which receive guaranteed recovery: we agree with the DRA and others that this could lead to the double recovery of the discounts. Moreover, we want discounts in the noncore market to come from the utility's fixed cost margin, not from a balancing account; in our program, this direct risk of margin recovery has always been the quid pro quo for the rate flexibility which we have granted the utilities in the noncore market. At this late date, we will not alter such a fundamental premise of our rate design.

Generally, we will allow the utilities to establish an amortization account to provide for recovery of those transition costs which we will assign to the noncore demand charge. These items are those whose magnitude and reasonableness has already been established and which are basically beyond the influence of utility management. The cost items assigned to the amortization account, following a reasonableness review in a cost re-allocation proceeding, will be recovered in noncore rates through a uniform transition cost surcharge applied to the demand charges of all noncore customers. Revenues from this surcharge will flow into the amortization account. This surcharge will change in future re-allocation proceedings as new transition costs enter the amortization account or as old costs are fully recovered. The surcharge may also be adjusted to reconcile forecasted and actually-incurred transition costs. The utilities can maintain the surcharge until the amortization account is paid off. As discussed above, the utilities may not discount this surcharge, because the ultimate recovery of these transition costs is assured. We also recognize the need for some flexibility in the amortization periods for various transition cost items included in the demand charge. For example, the GEDA stipulation calls for a five-year recovery of remaining GEDA costs; the EL Paso liquids settlement costs will be paid over two years. We will adopt specific amortization periods in the detailed discussion which follows.

Finally, we will not allow such treatment for transition costs assigned to the noncore volumetric rate. We strongly agree with DRA and CMA that to allow guaranteed recovery of such costs would dilute the incentive that we wish to create with that assignment. Volumetric transition costs will be treated just as any other non-gas cost allocated to the noncore market -- the utility will be at risk for their recovery. As with the other transition cost items, we may vary the amortization period, depending upon the magnitude and characteristics of any particular cost item.

Take-or-pay costs

At the present time, the FERC requires pipelines to use one of several specific ratemaking treatments for take-or-pay costs. These treatments include 100% commodity sales rate treatment; an equal percentage of take-or-pay costs directly billed to customers and absorbed by the pipeline's shareholders; or a combination of the three in which the pipeline's shareholders absorb between 25 and 50% of the take-or-pay costs, an equal amount is directly billed, while the remainder is included in volumetric sales or transportation rates. All of these mechanisms involve substantial risk of cost absorbtion on the part of pipelines. Not surprisingly, pipelines have not rushed to utilize such rate mechanisms and are appealing the FERC orders mandating such treatment. As a consequence, today we are faced with only a small amount of take-or-pay transition costs -- slightly less than $6.5 million in total -- which have been incurred by PG&E.

However, take-or-pay costs have the potential to be the single largest item of transition costs which California will face. The claimed liability of Transwestern and El Paso to their suppliers will reach nearly $2 billion by the end of 1988, according to testimony filed by the pipelines in recent proceedings at the FERC. Even if such liablities are extinguished for 10-20 cents on the dollar, California's share of such costs could be substantial. Accordingly, we take seriously our decision to allocate such take-or-pay buy-out and buy-down costs to volumteric rates. We believe that this treatment is necessary so that take-or-pay costs will be placed under competitive pressure. If take-or-pay costs become too excessive, the non-core market can be expected to switch to alternative fuels. To prevent this, the pipelines and their producers must attempt to minimize such costs, and the utilities must vigilantly resist pipeline attempts to pass through imprudently incurred costs or unreasonable amounts of take-or-pay costs.

We view take-or-pay costs as excess inventory costs, which, whatever their standing in past industry practice, could not be recovered by sellers in a truly free market economy, in the face of competition from sellers unburdened by such costs. Volumetric rate treatment of such costs will most clearly send signals to the sellers of such gas when take-or-pay costs make gas a less competitive resource.

We note that TURN has suggested that the California utilities be provided the same options as FERC-regulated pipelines with respect to the recovery of take-or-pay, that is, such costs could be at least partially directly billed, reducing the pressure on the utility's volumetric rates, in exchange for the agreement of the utility to absorb a portion of such costs. Given the small amount of take-or-pay costs at issue in this proceeding, we decline to adopt such a suggestion. The impact of take-or-pay costs as a proportion of PG&E's total transition costs is quite small. We do reserve judgement on whether or not to adopt such an option for the recovery of take-or-pay costs in the future, particularly because the amount of dollars actually charged to California utilities is so uncertain at this time. The actual magnitude of such costs is a significant factor to consider in any such decision.

Clearly, at some point, after pipelines have had a reasonable time to reform their old contracts to conform to competitive markets, transition treatment of take-or pay costs must end. We also reserve judgment on the rate treatment for the so-called gas reservation charges which the FERC is considering as a means to prevent the incurrence of take-or-pay in the future.

The El Paso Liquids Settlement

Recently, the FERC approved a settlement, with the support of this Commission, to approve the direct billing of the liquids undercollection to El Paso's customers as well as the undercollection which would have built up before the effective date of El Paso's next rate case. As discussed above, these costs clearly fit within our definition of a transition cost. They were incurred prior to the portfolio split, were associated with a gas supply destined for all customers, and under FERC rules, would have been recovered from all pipeline sales customers. Because the amount of liquids costs to be directly billed in this fashion is fixed, and thus cannot be affected by competitive pressures, we deem it appropriate to place such costs in the utilities' demand charges. No objective of our restructuring plan would be served by assigning such costs to the volumetric rate. The utilities should amortize this item over the same length of time over which they are being billed by El Paso: two years.

Excess Gas Costs Associated with Minimum Purchase Obligations

We have discussed at length the problems associated with evaluating "excess gas costs". These costs might best be characterized as those gas costs in excess of a reasonable amount which would be paid in a competitive market, which are still being paid by some of the utilities' customers. The underlying theory is that to the extent some customers are "stuck" with such costs during the transition to a competitive market, all customers should share the burden of the costs of the transition by bearing a portion of such excess gas costs. Without question this is a difficult type of cost to calculate precisely. In particular, the choice of the "reasonable cost of gas" against which the excess costs are measured is subject to a substantial amount of judgement and discretion, especially at a time when the future structure of gas purchase arrangements is so uncertain. As a result, we have been reluctant to define as a transition cost any excess gas costs other than those which appear clearly to be a high-cost remnant of the previous regulatory environment. As we have discussed above, this is the case with respect to the high commodity costs of certain gas supplies which also continue to carry high minimum purchase obligations.

With respect to the rate treatment of these excess gas costs, we conclude that volumetric rate treatment is appropriate. These gas costs are clearly expenses which the utilities do have the ability and indeed the responsibility to manage. To the extent that volumetric rate treatment provides an incentive for the utility to minimize these costs, it sends precisely the correct signal. During this transition period, the utilities should be actively engaged in shedding or renegotiating supplies which are priced significantly above what can be obtained in the competitive market. In particular supplies such as the POPCO and California gas purchased by SoCal are troubling because they will be allocated to the core portfolio. We wish to make it clear that the core portfolio was never intended to be a "purchaser of last resort" for uncompetitive supplies which the utility's other customers will not buy. Therefore, it is appropriate for the utility to bear the risk associated with including a portion of these excess gas costs in the volumetric rate for non-core customers, until the costs of these supplies can be reduced. We will allow a two-year amortization of these costs; SoCal should establish a tracking account to reconcile the forecasts of these costs with those which are actually incurred between cost re-allocation proceedings.

The length of time this treatment will continue is also of concern, especially to those customers who have to bear these costs. We will not decide the exact length of time such treatment will continue at this time, but will reexamine this item of transition costs during future reallocation proceedings. We will indicate, however, that such treatment will continue to serve as a useful incentive to the utilities so long as the cost of these high priced supplies is not renegotiated.

<u>Other Transition Cost Items</u>

The remaining transition cost items are GEDA, Order 94/270 costs, and storage-related transition costs. These cost are already established and arguably are beyond the control of the utilities. Consistent with our general approach, they will be assigned to the demand charge. GEDA costs should be amortized over five years, consistent with the DRA/utility stipulation; the other items should be recovered over one year.

B. Industrial Sales Forecasting

In the past, the forecasting of sales was an exercise of little controversy because of the presence of the SAM balancing account. Now that the utility will be at risk for recovery of the fixed costs allocated to the noncore, the sales forecast has become a critical and hotly contested issue. The stakes were raised even more when we set a ceiling rate equal to embedded costs. Without the flexibility to charge rates above embedded costs, there was an incentive for the utility not to offer discounts below embedded costs. However, if rates were set on the basis of no discounting, and the utility later did offer discounted rates, then the utility would have had an opportunity to gain large windfall profits.

SoCal produced a forecast for industrial sales that contained a no-discounting assumption. However, the scrutiny given to the SoCal forecast in the record shows that the utility actually estimated that there would be very little load lost. The parties generally agreed that the SoCal forecast could be used for this proceeding. We will use the SoCal forecast for this proceeding because it produces a result likely to be close to the one which would result from the method which we will adopt today for use in future re-allocation proceedings. In the future, all three utilities will use the same method -- the method adopted for PG&E in this decision.

PG&E on the other hand took the no-discounting assumption to the limit and as a result estimated very large lost loads. The DRA, on the other hand, forecast sales as if all discounts were made but did not account for the lost revenues--the other extreme. These lost revenues could be as great as $43 million.

The DRA method appears to be unlawful and the PG&E method unreasonable. Into the controversy entered TURN. TURN put forth a forecasting methodology for PG&E that recognized that rates would have to be discounted to certain customers and that the discounts would result in decreased revenues. The TURN method in essence estimates the amount of sales that can be retained by discounting and then allocates costs in the amount of the discounted rates to those sales; as a result, the larger sales base is retained and the utility does not suffer an automatic revenue shortfall. In their final comments PG&E and the DRA expressed conceptual support for the TURN method. The TURN method is adopted for PG&E. Because TURN's method appears to capture accurately the impact of discounting on the sales forecast, we will also require the utilities and other parties to use it in future re-allocation proceedings.

The one element of controversy in the TURN method is the judgmental decision regarding the percentage of potential lost load that can be retained. Using the PG&E model which recognizes the effects of rate design on sales, the method produces a market retention of the load in question of about 60%. The ALJ's proposed order raised the retention percentage to 75% on the grounds that PG&E's rate design effect model has not been used before this proceeding nor verified by DRA. PG&E in its comments complained that there was no record evidence that its model was defective. Actually, TURN's testimony suggests a more persuasive rationale for such an adjustment: the upstream pipelines and producers could be assumed to bear a portion of the burden of discounting. The DRA storngly supports this reasoning. However, in the absence of any experience with a flexible rate design, we find no basis for making or quantifying such an assumption at this time. We agree with PG&E that to make such an arbitrary adjustment to the sales forecast would deny the utility a reasonable opportunity to meet its revenue requirement. We do urge the parties to study the quantification of such an adjustment as a possible refinement to the TURN method for use in future cost re-allocation proceedings.

C. Priority Charge

SoCal and PG&E produced two different conceptual approaches to implementing a priority charge. The other parties in turn generated a number of different suggestions for the details of how each of these approaches should work.

PG&E asks us to define the priority charge as the difference between the average gas transport rate a customer pays for a given period and its average rate calculated on the default tariff for the same period. Presumably, the greater this difference, the lower the priority a customer would receive. The highest priority would go to customers who agree to pay more than the default rate, with the increment above the default rate constituting the priority payment. PG&E believes that their approach has the benefit of reflecting the cost to serve the customer (the default rate) as well as the value of the service to the customer (the actual transport rate paid). PG&E thinks that its method has the benefit of placing noncore customer classes with different default rates on an equal footing with respect to priority charges. PG&E's approach is supported by the DRA and by CMA and SCMunis, who suggest the modification of basing the priority ranking on the ratio of the negotiated rate to the default rate.

SoCal proposes to have customers bid priority charges for each season. The results of this bidding would determine the priority ranking for the next season. An inquiring customer would be shown this ranking, with other customers identified by SIC code and with the inquirer's ranking shown on the list. A user could split his load into at most two parts in order to bid different priority charges for each part. TURN supports the SoCal proposal. Shell Canada, Long Beach, and CSC suggested minor modifications to the SoCal plan.

Even PG&E admits that the SoCal proposal is the method which we described in D. 86-12-009 (pp. 46-47): a separately-stated, "unbundled" charge whose function would be to ration short-term capacity on the utility's system. PG&E's approach essentially produces a charge that remains "bundled" with the overall transportation rate; for a customer to improve his priority, he must renegotiate upward his entire transportation rate. Because the priority charge is thus bundled into the overall contract, we agree with TURN that the PG&E approach will not reflect the value of short-term capacity as well as the SoCal system. PG&E also argues that SoCal's method could curtail customers with higher overall rates but lower priority charges before those paying lower overall rates with higher priority charges. But under the PG&E method as we understand it, this result is also possible: for example, a customer who pays her full default rate of 10 cents per therm would have a higher priority than a user with a 12 cents per therm default rate who pays a negotiated rate of 11 cents per therm. Finally, we also agree with TURN's comment that the PG&E method does not readily accommodate the highly elastic customer with very competitive options to utility gas service, who may also desire a high priority of service. If we believe its representations, the EOR market provides the classic example of such customers; industrial customers with low-priced alternate fuel capability may also fit this description. Such a customer may require a significant discount in the transportation rate to retain him on the system, yet may be willing to pay a priority charge to insure reliable service when capacity constraints develop. SoCal's "unbundled" priority charge seems the best way to meet the needs of such customers.

For these reasons, we will adopt SoCal's priority charge proposal. The adopted mechanism is described below in a quote from the SoCal brief:

> "SoCalGas proposes to have customers bid priority charges for each season. A listing of noncore priority ranking (and the amount of the priority charge paid) and associated volumes (but without customer names) would be provided to any noncore customer on request. The listing would identify each customer by Standard Industrial Code (SIC), and would also identify the priority ranking of the inquiring customer. SoCalGas would require the bids for each season to be submitted 60 days before they are to be effective. SoCalGas would permit a customer to split his noncore load into a maximum of two parts for purposes of bidding different priority charges for each part."

Finally, several parties, principally CMA and Shell Canada, urge us to address the unanswered question of the disposition of priority charge revenues. We concur with Shell Canada that priority charge revenues represent a transfer of capacity among noncore users. There is no additional service provided by the utilities in exchange for the priority payment, except perhaps the minor administrative service of supervising the priority system. We agree with CMA and Shell Canada that the priority charge is intended to ration capacity and to provide an efficient signal of the need for capacity expansion, not to provide the utilities with an additional value-of-service-based revenue source. Rebating priority charge revenues to noncore customers would ensure that the utilities do not collect noncore capacity costs twice, and, as Shell Canada notes, would reduce the possibility that a utility might agree to restate a total transportation rate in order to increase artificially the priority rate. Thus, the utilities should track priority charge revenues when they begin to receive them, and in the next cost allocation proceeding we will use the accumulated revenues to offset intrastate capacity-related costs assigned to the noncore market. The exact mechanism for this rebate can be decided at that time.

D. Core/Noncore Customer Definition

In Decision 86-12-009, we defined the core class as customers with end-use priorities P1, P2A, and P2B, while other retail customers were defined as noncore. Later, in D.87-02-029, we expanded the definition of noncore service to include large P2B customers--those using in excess of 250,000 therms annually, or 20,800 therms per month. The end use priority definitions are shown below:

P1 - All residential use regardless of size.

- All other service to customers with peak-day demands of 100 mcf or less.

P2A - All service where primary use is as a feedstock or other non-residential use in excess of 100 mmcf per day where the use of an alternate fuel is not feasible.

- Other uses where specific CPUC authorization has been granted. Electric utilities' start-up and igniter fuel fuel use.

P2-B - All service to customers with LPG or other gaseous fuel standby facilities where conversion to alternate fuel is not feasible.

- Other uses where specific CPUC authorization has been granted.

During the evidentiary hearings in this phase issues concerning the core definition were raised at our invitation. The first issue is whether P1 customers with alternative fuel capability should be classified as core or noncore. These customers can use a fuel other than natural gas but receive core designation because they use less than 100 mcf on a peak day. Reclassification is also an issue for small P2B who might fuel switch rather than pay core rates. There is also the issue of whether or not a customer must have the alternate fuel facilities actually on site rather than a mere technical feasibility of alternate fuel use.

PG&E, supported by TURN and to a limited extent DRA, proposed that the utilities be allowed to reclassify as noncore certain small core customers with the technical capability to use alternate fuel. To qualify for this reclassification, the customer would have to meet certain conditions, as follows:

> "These requirements should include customer demonstration, to the utility's satisfaction, of the ability to use alternative fuel on a sustained basis. They should also include a demonstration that such alternative-fuel use would be an economic alternative to core service. Finally, the customer must be willing to accept the lower transport and procurement priority associated with noncore service. If a customer meets all of the requirements, the utility should be allowed to reclassify the customer as noncore."

SoCal argues for the retention of the present definition because for many customers only a small portion of this load is capable of alternate fuel use, and is infrequently subject to fuel switching. Regarding the requirement that actual stand-by facilities be in place, both SCE and SDG&E argue for the retention of the requirement because it is a primary distinction of noncore customers. Also, without this requirement they believe that there may be a large exodus of core customers into the noncore.

We will adopt the PG&E proposal for the small alternate fuel capable customer, based primarily on our belief that the core/noncore distinction should be based on the alternate fuel capability and not on the size of the customer. If the customer passes the tests adopted (including PG&E's economic test) then the utility may reclassify the customer as noncore; we think that it is wasteful to create the incentive for a customer to invest in unneeded facilities in order to be afforded noncore status.

III. Throughput Forecast/Cost of Gas

The resolution of the issues discussed earlier now permits a more orderly consideration of the remaining issues. During the course of the proceeding, a "decision matrix" was developed. This matrix is an organization of the issues in this case that allows the development of rates in a linear fashion. Simply put, the issues raised by the parties were reorganized in order to facilitate the step-by-step determination of the revenue requirement, revenue allocation, and then rate design. This matrix was the foundation of filed briefs, the subsequent ALJ ruling, and the ALJ's draft decision. To the extent possible, we will continue to use the matrix as the outline for the remainder of this decision.

In arriving at the rates we will implement through this decision, we will follow the logical progression from sales forecast through cost allocation and finally to rate design. Each of the issues which we will resolve individually in the sections that follow will relate ultimately to one or more of these three major steps.

We first resolve the issues involving sales forecasts. Until recently, virtually all deliveries by California gas utilities have been of utility-owned gas. Transportation of customer-owned gas was a relatively rare occurrence and we could speak of "sales" as the measure of how much gas was being consumed by end-users in California. This is clearly no longer the case, and we draw a distinction in this decision between "sales" (delivery of utility-owned gas) and "throughput" (all gas deliveries, whether utility- or customer-owned).

The throughput forecasts we adopt become a major input into a subsequent ratemaking step -- the allocation of the utilities' fixed cost revenue requirements. The sales forecasts we adopt will be used to construct the procurement portfolios we develop in the next section. The distinction is important: throughput tells us how much gas the utilities will move, and sales tells us how much gas the utilities will buy.

Because our adopted gas industry structure eliminates balancing account protection for non-core throughput, our throughput forecast is the first step in assigning risk to the utilities. The more throughput we forecast for the non-core relative to the core, the more risk we place on the utilities. Our task has been made doubly difficult by two factors: the potential for some throughput to be captured by discounting (either by the utilities, the pipelines, or the producers), and the forecast-rate-forecast "feedback" effect.

We discussed the discounting problem in Section II.A above, adopting TURN's method for capturing the potential impact of discounting on the sales forecast. The feedback effect requires some explanation. One important variable in a forecast of the consumption of any product is the price of that product. If the result of the forecast is then used in designing rates, the rates developed may not be the same as were assumed in doing the forecast in the first place. Short of indefinite iterations of our forecast-allocation-rate process, the best we can do is to ensure that reasonable rates are assumed in the beginning, and then remain mindful of the effect throughout the rate design process.

We now resolve the specific issues regarding our throughput and sales forecasts.

A. Forecast of Sales/Deliveries

1. UEG Forecast

The primary issue surrounding the forecast of gas deliveries for powerplant use is how to achieve both fairness and consistency. We want to adopt a throughput forecast that the utility has a fair opportunity to realize. In addition, the gas utilities desire that the sales forecast be consistent with the adopted gas prices. Other parties propose that the UEG sales for the gas utilities simply reflect the forecasts of the amounts purchased by the electric utilities, as adopted in a recent electric rate offset proceeding. Use of the ECAC forecasts would be consistent with our traditional practice in gas offset cases. Therefore, the issue is: should there be internal consistency within the gas decision or should there be consistency between the forecasts that we adopt in two different decisions made within the same time frame? The ALJ's draft order adopts the forecasts which are consistent with the most recent electric rate offset cases.

For SoCal Gas, we believe that the forecast of UEG gas use developed in SCE's electric offset proceeding, adjusted for the slightly differing time periods, is reasonable for use in this proceeding. We recognize SoCal's concern, expressed strongly in its comments on the ALJ's draft, that the forecast UEG sales must be consistent with the adopted prices. Based on our review of the record, we feel that the incremental UEG gas price (the noncore portfolio rate plus the UEG volumetric rate) is consistent with the incremental gas price used in the SCE ECAC case[1]. In addition, we have more confidence in the treatment the electric fuel mix

1 D. 87-11-013 in SCE's most recent ECAC case adopted a forecast of $1 per MMBtu for SCE's incremental gas purchases for the June, 1987, through 1988, forecast period (see Table B-1). This is equivalent to a spot gas forecast of $1.75 per MMBtu, as adopted in this order, plus a UEG volumet rate of $0.21 per MMBtu, which is very close to the rate actually adopted today.

questions received in the electric offset case than, for instance, in SoCal's UEG forecast. SCE pointed out that SoCal's forecast is based upon a CEC filing that was not intended to be used for short-term forecasting. We view this resolution as appropriate for this case alone; later we will discuss a more systematic approach to forecasting UEG and other noncore demand which we would like to see followed in future re-allocation proceedings.

The PG&E UEG forecast presents a more difficult situation, due to the dramatic effect which hydro conditions can have upon gas use on the PG&E system. The DRA forecast, based on a dry year scenario consistent with the most recent PG&E ECAC case, is roughly 50% higher than the average year PG&E estimate. For the future, we believe that fairness dictates that PG&E's (and SoCal's) UEG forecast should be based consistently upon an average hydro year. We expect that all parties should accept this practice, especially if the PG&E cost re-allocation case is held in the fall, before the next year's hydro conditions are known. The problem with using an average year in this case has been that all parties have known that the beginning of the forecast period would be a dry year. That has made it difficult to reject the DRA's forecast. However, PG&E does have a valid point when it notes that the forecast period will be almost concluded when the rates approved in this order take effect. Unfortunately, there appear to be several problems with PG&E's average year forecast; cross examination revealed that the forecast assumes the return to operation early in 1988 of the Rancho Seco nuclear power plant. It would be indeed ironic for PG&E's Gas Department to profit from a forecast assuming Rancho Seco's early ressumption of operations, when the company is pursuing vigorously an effort to purchase SMUD, a campaign whose centerpiece is the permanent closing of "The Ranch." In this situation, we feel that it would be inequitable to either ratepayers or shareholders to adopt either extreme of the PG&E or DRA forecasts. Therefore, for the purposes of this case only, we will adopt the average of the PG&E and the DRA forecasts as an equitable estimate of PG&E's powerplant gas use.

In adopting this forecast, we are rejecting the proposition put forth by SDG&E that the fixed costs associated with UEG gas purchases should be included in establishing a gas forecast. Powerplant dispatching decisions should follow the incremental rate.

2. Forecast of Sales versus Transport Only

The split of the total throughput forecast into sales and transport-only portions impacts estimates of total revenue. This issue is significant because one proposal for allocating balancing account balances is to use an equal-percent-of-total-revenues basis. Total revenues can vary substantially based on the amount of utility gas sold.

There was no substantial disagreement with the utilities' methods of determining the split between transport-only and sales; therefore, the utilities' methods are adopted.

3. Alternate Fuel Prices

The price for alternate fuels--although not crucial for rate design--is still an important input for the sales forecasting models. The testimony indicates that the sales forecasting models are not extremely sensitive to small differences in alternative fuel prices. These fuel prices are likely to be very unstable and are therefore difficult to forecast with any degree of reliability.

The DRA and the utilities were not far apart on this issue. TURN supported a higher set of prices. The prices that we will adopt are as follows:

1.	#6 high sulphur	= 26.78	cents	per	therm
2.	#6 low sulphur	= 29.67	"	"	"
3.	#2	= 33.98	"	"	"
4.	propane	= 27.00	"	"	"

These prices for #6 are based on the testimony of PG&E, #2 on the testimony of SoCal, and the propane on the cross examination and argument of CMA.

4. Price Premium for Gas

A price premium for gas versus alternative fuels will lead to a higher noncore forecast than without one. There is no general agreement among the parties over the existence of a premium. PG&E assumes a 2 cents per therm premium over alternate fuels. SoCal assumes a high but unquantifiable price premium. Others, namely CMA and the Food Processors, testify that the existence of a price premium is dependent on the particular circumstances of each customer and that no general position can be adopted. We do believe that it is possible and worthwhile to choose an average premium for the limited purpose of forecasting industrial throughput. PG&E's testimony convinces us that such a premium does exist and that 2 cents per therm is a reasonable value for the premium, especially in light of the fact that we have chosen rather low alternate fuel prices as model inputs.

5. Core-elect/Noncore Procurement Forecast

The testimony has shown that the core portfolio cost of gas is rather insensitive to the amount of core election. Also, with no experience under the new system no party had a strong basis for their projections. Based primarily on the testimony of PG&E and DRA, we will adopt the following amounts core election:

1. PG&E - an amount equal to its UEG sales.
2. SoCal - an amount equal to 25% of its noncore, nonUEG sales, including cogeneration sales.
3. SDG&E - an amount equal to 25% of its noncore, nonUEG sales, including cogeneration sales.

6. Definition of a Cold Year

The definition of a cold year has an impact on the allocation of various components of the embedded cost of service. Since the core market is more temperature sensitive than the noncore, a more extreme definition has the effect of allocating more costs to the core.

The definitions to choose from are:

1. One standard deviation from the mean. (One year in seven)

2. Two standard deviations from the mean. (One year in 35)

3. 2.46 standard deviations from the mean. (One year in a hundred)

TURN supports one standard deviation from the mean based upon the concept that we wanted flatter allocation factors and also so that this decision is consistent with the Commission's FERC testimony in the EOR Pipeline cases. The Commission's testimony utilized one standard deviation from the mean. In any event, TURN proposes that all three utilities use the same definition.

The PG&E proposal of two standard deviations from the mean is consistent with the filings that it makes with other state agencies such as the CEC. This definition is also more reasonable for system planning purposes. The SoCal and SDG&E proposals are slightly more conservative and generally based on the same reasoning. DRA took no position on this issue.

We will adopt the two standard deviations from the mean definition of a cold year based on the testimony of the utilities. The definition will be consistent for all three utilities as TURN proposed. It is also our intention that the definition that is used for cost allocation purposes be close to the definition that the utilities use for system planning purposes.

7. <u>EOR Forecast</u>

We will adopt the PG&E estimation methodology which was supported by DRA and was not contested by other parties.

SoCal does not object to the DRA estimate as long as the current ratemaking and accounting treatment for EOR throughput is maintained. The DRA estimate is adopted for SoCal.

8. Cogeneration Forecast

The staff and the utilities are in general agreement on the cogeneration sales forecasts. These forecasts were not contested by other parties. Each utility's forecast will be adopted.

9. Interutility Volumes

This issue was hotly contested, with the utilities refusing to forecast any significant volumes of interutility transportation, and with the Canadian producer interests proposing very large volumes. It is clear that there is a large supply of gas available and also a large demand for cheap gas (in excess of 300 mmcfd through the PG&E system). What is unclear is the amount of room in the pipe that will be available.

PG&E makes a substantial case regarding the difficulty of making these initial forecasts. Nonetheless, we feel that the DRA and the Canadian parties have adequately established that there is a substantial potential for interutility transportation during the forecast period. Due to the uncertainties inherent in this initial forecast for this new service, and because interutility transportation will be served at the lowest priority, we will adopt conservative numbers at this time. The DRA estimate of 100 mmcfd is the basis for our adopted number of 127 mmcfd of third party gas to be moved in interutility transportation at ceiling rates over the PG&E system. The additional 27 mmcfd is the amount of excess PITCO volumes which SoCal itself expects to receive through interutility transportation. The CPG asks us to at least double the DRA estimate of 100 mmcfd, on the grounds that A&S gas will not be able to compete with third-party Canadian gas. Because our procurement and off-system sales policies are under review in I. 86-03-036, we will not prejudge the outcome of that inquiry by forecasting that A&S gas will not be competitive in southern California.

SoCal continues to forecast that there will be no interutility transportation based upon its estimate that Transwestern will be at capacity for the forecast period. DRA forecasts 40 mmcfd. It estimates that Transwestern will have some excess capacity during the forecast period. The SoCal argument is based on their showing that the Transwestern capacity will be used to buy gas for storage for the remainder of 1987 and then will be used for spot purchases. Given these arguments, we will adopt a figure equal to 50% of the DRA estimate, or 20 mmcf/day, to be transported at the ceiling rates.

10. Wholesale Forecast

There is no disagreement over the PG&E wholesale forecast, which includes Palo Alto's estimate of its purchases. The PG&E forecast will be adopted.

For Socal, we will adopt the SoCal's estimate, modified to reflect the sales and throughput forecast adopted for SDG&E. Any differences among the parties are not substantial.

11. Future Noncore Throughput Forecasts

In providing demand forecasts for the noncore market in future cost allocation proceedings, utilities shall give explicit consideration to the impact of natural gas supply prices and transmission rates on the demand for natural gas. We have adopted the TURN forecasting method to capture the impact of competition with alternate fuels. The utilities shall present showings that indicate the manner in which price elasticities are included in their forecasting methodologies. These showings shall include a description of the data used, how it was obtained, and the methodology used to develop price elasticities or alternative price response estimates from the basic data. Utilities should show how these price elasticities combine with their assumed gas and alternative fuel prices to determine the noncore forecasts.

In addition, the forecasting utilities should validate the models used for noncore forecasts pursuant to P.U Code Sections 1821 to 1824. This will reduce the need for litigation of gas forecast models in future proceedings and bring us more in accord with the requirements of those sections.

12. Adopted Sales and Throughput Forecasts

At this point we have resolved the issues that affect the forecast of sales and throughput. The tables below are the result.

B. Gas Costs and Portfolio Prices

Now that we have adopted specific sales forecasts for each utility, the next step in developing rates is constructing the two gas procurement portfolios we have established for our new gas industry structure -- the core portfolio and the non-core portfolio. It is important to remember that the portfolio prices we adopt apply to the procurement function only and not to the transmission function. That is, customers who have the option to move gas they already own need never face the portfolio price.

In our new industry structure, as established in D.86-12-010), non-core customers have the option of (1) buying their own gas and using the utilities only for transmission, (2) being served from the non-core portfolio, or (3) electing to be served from the core portfolio. Very large core customers may also choose between service from the core portfolio or transmission of their own gas, but most core customers must purchase both procurement and transmission in a bundled rate that includes the core portfolio price.

D. 86-12-010 set forth general guidelines for the type of supplies which we expect the utilities to procure for the core portfolio. These guidelines include 1) the certainty of supply availability to meet core peak requirements, 2) greater price security than can be obtained on the spot market, and 3) meeting the first two objectives at the lowest cost. In the same decision, we directed that the non-core portfolio be constructed of spot gas. We recognize that gas procurement practices are changing rapidly in the newly-competitive gas industry, and we are conducting a separate investigation (I. 87-03-036) to consider further changes in the general policies for gas procurement which we outlined in D. 86-12-010. The intent of this order is not to undertake a significant discussion of procurement policies; its purpose is to implement an unbundled rate design. Therefore, at this time we will construct the core and noncore portfolios using the utilities' current mix of supplies and generally following the companies' current practice for sequencing purchases from these suppliers. In doing this, we acknowledge -- as we have discussed at great length above -- that our treatment of transition costs, especially the potential excess gas cost component, can have an influence on the utilities' procurement practices.

1. Supply Prices

We have updated our gas supply prices from those used in the ALJ's draft decison. The update reflects El Paso's and Transwestern's latest price filings at the FERC, and the changes which have occurred in the California utilities' forecasted purchases as a result of these price changes.

The most controversial issue in the area of gas prices involves the estimate of spot prices. DRA estimated 17.5 cents per therm and PG&E 17.8 cents per therm. SoCal on the other hand forecast 19.0 cents per therm. SoCal's estimate is based on its analysis that the so-called gas bubble will go away over the forecast period. DRA and PG&E base their estimates on the recorded prices and trends over the last year. Neither forsee the likelihood of dramatic spot price increases over the forecast period. We will adopt the DRA estimate of 17.5 cents per therm.

2. Demand Charges

The utilities' forecasted demand charges were virtually uncontested. The one element under question was the demand charge that PG&E pays to PGT. FERC has allowed the PGT demand charge to be reduced from $43.9 million to $35.1 million. We will recognize the FERC authorized demand charges of $35.1 million.

3. Supply Volumes (Sequencing)

As we indicated in our introductory remarks, this proceeding was not intended to decide the reasonableness of the utilities' sequencing practices. We have requested comments in I. 86-03-036 on whether we should revise our sequencing policies. This decision requires a reasonable estimate of gas costs over the forecast period. We will adopt the methods used by the utilities to forecast their gas takes from various suppliers. We are satisfied that their forecasted takes accurately follow current sequencing practices, and we decline to prejudge I. 86-03-036 by forecasting a change in policy at this time.

4. Core Weighted Average Cost of Gas (WACOG)

To arrive at the core and core-elect WACOG simply requires the removal of cost of gas related transition costs from the cost of gas arrived at in the above discussion.

5. Noncore WACOG

Our new program of regulation requires that the noncore WACOG reflect spot prices currently in effect. As discussed above, we expect spot prices to average $1.75 per MMBtu over the forecast period. For the purpose of illustrating rates, we will use this average as the noncore WACOG, although of course in practice it will vary each month.

6. SDG&E

Very briefly, the SDG&E cost of gas is derived directly from the rates adopted for SoCal Gas.

7. Adopted Cost of Gas

At this point we have resolved the issues required for the development of the cost of gas tables shown below:

IV. Allocation and Revenue Requirement Issues

Using the throughput forecasts we adopted in Section III. A., we can now allocate each utility's revenue requirement among the various customer classes. Once we have accomplished this allocation, we can begin to develop actual transmission rates for each class. Allocating the revenues requires us to use "allocation factors" to split each cost item (e.g., transmission, storage, administrative and general expenses) among the different customer classes (e.g. residential, industrial, UEG). Nearly all of the allocation factors we develop are directly related to our adopted throughput forecast.

When choosing allocation factors, we attempt to reflect the way each cost item is actually incurred. For instance, if we believe that a particular cost is incurred year-round according to the amount of throughput, we might allocate that item by annual throughput. If, on the other hand, we believe that a cost is incurred only during the winter, we might allocate that item by winter throughput. Cost allocation is regretably not an exact science; two different allocations may both reasonably reflect cost incurrence, yet produce significantly different results. Therefore, any cost allocation involves an element of judgement. For example, in D. 86-12-009 we decided to choose relatively "flat" allocation factors, which spread costs more evenly across the customer classes, in recognition of the current excess capacity in the utilities' systems. Ultimately, our goal is to place the allocation process on the firmer foundation of marginal costs.

As we noted in the introduction to this order, we have decided not to revisit the choice of allocation factors which we made in D. 86-12-009 until such time as the current excess capacity has been substantially reduced. Therefore, the cost allocation issues which we resolve today are generally matters not resolved in D. 86-12-009, or questions concerning how to implement the cost allocation process adopted in that decision.

A. <u>Allocation of Embedded Costs</u>

1. <u>EOR Revenue Treatment/Cost Allocation</u>

D.87-05-046 established a special procedure for the tracking and crediting of revenues generated by service to the EOR market. This treatment is in recognition of the fact that the EOR customer may have the competitive option of service through one of the proposed interstate pipelines. Two issues arose in this case regarding that procedure. The first is whether a forecasted credit should be included as an offset to the revenue requirement at this time. The second is how such credits should be allocated.

On the first issue, concerning whether or not to forecast and credit in this proceeding, PG&E and DRA take the position that a tracking account be set up but that no forecast of EOR revenues be made at this time. Rather, they propose that the credits be flowed through in a future period. This procedure would guarantee no undercollections.

SoCal, TURN, and CMA, on the other hand, propose that a forecast be made and credits flowed in this proceeding. This is based on the arguments that (1) current ratepayers should benefit from current EOR service and (2) decreased non-EOR rates will help the utility maintain or increase throughput.

The amounts of the forecast are not in question--$2.6 million for PG&E (proposed by TURN) and $21.2 million for SoCal. We will adopt these revenues as a current forecast and provide tracking account treatment to record any difference between forecast and actual revenues. Any discrepancy will be trued-up in the next cost re-allocation case.

The next issue is to determine the mechanism for the allocation of EOR revenues. The PG&E proposal was not very clear on this issue. However, in its brief PG&E suggests that the credit be given to customers according to the ratio of transmission and/or other functional revenue requirements allocated to other customer classes.

CMA proposed a rather complicated formula which was designed to provide the credit to the classes according to the assignment of costs to various functions. If that procedure was deemed too complicated, then CMA proposed that the credit be made on an equal cents per therm basis.

SoCal proposed that the credit be flowed back based on the allocation of fixed costs. TURN supports the SoCal proposal as being the only proposal that meets the requirements of D.87-05-046, wherein we stated that the credit would be taken off the top of the margin requirement before functionalization and classification. We will adopt the SoCal method because it does indeed comply with our previous decision.

2. <u>Weighted Customer Allocation Factors</u>

Under prior decisions, customer-related costs are to be allocated on the basis of weighted number of customers (D.86-12-009). In this case DRA and SoCal have based the weighting factors on the relative direct plant investment for each customer class; most particularly to access equipment. This approach is supported by TURN.

PG&E, on the other hand, based its weighting factors on marginal customer premises installation costs for typical residential, commercial, and industrial customers. We will adopt the SoCal, DRA, TURN approach because it is more consistent with an embedded cost allocation methodology. This might be reconsidered when we begin using a marginal cost methodology.

3. <u>Customer Related Transmission Costs</u>

This term is used by TURN to refer to costs which it proposes be specifically assigned to customers or customer classes, rather than being allocated. In D.87-05-046, we granted a SDG&E request to directly assign the costs of some SoCal transmission facilities to SDG&E. TURN proposes that we in like manner directly assign $1.2 million dollars of SoCal cost to its UEG customers.

The utilities have allocated these costs in accordance with our prior decisions. TURN has not made a convincing showing that the method should be changed at this time. We will adopt the utilities' methods. This issue can be reexamined in the next set of re-allocation proceedings.

4. Allocation of Conservation Costs

The utilities' current revenue requirements include both base rate and offset conservation program costs. PG&E and SoCal each propose to treat base rate conservation costs as customer related, which means that core users will bear over 95% of such expenditures. For offset programs, both utilities propose that core customers pay 100% of the costs. TURN objects to these allocations and instead proposes that conservation programs be considered commodity-related, because the purpose of these expenditures is to achieve conservation of the gas commodity.

SoCal points out that in our previous decisions in this matter these costs were allocated as customer related and that its cost studies have historically treated these costs as such. Our review of D. 86-12-009 indicates that we considered only base rate conservation costs in the allocation decisions which we made in that order. TURN did produce evidence which suggests that allocating these costs as customer costs may assign too much to the core. However, consistent with our general reluctance in this order to revise already-decided allocations, we will not change the allocation of these base rate costs.

We have yet to decide the allocation of offset conservation costs. We see merit in the positions of both TURN and the utilities on this issue. It is true that in the past we have considered conservation to be a potential source of supply. We assessed the costs of the offset conservation programs on an equal-cents-per-therm basis to all customer classes except UEG, cogeneration, and wholesale. In this respect, these offset costs can be looked at as a past cost incurred for the benefit of residential, commercial, and industrial customers with the expectation that they would be recouped from these customer classes. We will, therefore, allocate the remaining CCA balances as we have in the past, on an equal-cents-per-therm basis to all customer classes except UEG, cogeneration, and wholesale. We note that this assigns the great majority (82% for SoCal) of the offset program costs to core customers. Finally, this allocation of the offset balancing accounts is consistent with our treatment of other balancing account balances.

5. Calculation of Noncoincident Peak Factors

This issue involves the proper interpretation of D.86-12-009 regarding how to calculate the allocation factors for demand-related common distribution costs. PG&E made its calculations on data based on total throughput. SoCal, on the other hand, based its calculations on information that was disaggregated down the the class level. TURN proposes that the sales disaggregation go down to the individual customer level. TURN also found certain errors in the PG&E showing, which was subsequently corrected. We believe that the SoCal method is a more accurate way to calculate this factor than the PG&E method. In addition, the SoCal method is the closest to our intent in D.86-12-009. We will adopt the SoCal approach.

6. Allocation of Franchise Fees and Uncollectibles

All parties appear to agree that Franchise Fees should be allocated on a percent-of-revenue basis and that Uncollectabless should not be allocated to wholesale customers.

We will explicitly adopt the allocation method of SoCal (which was supported by CMA) for the detail of this allocation issue. The SoCal method result closely matches the cost incurrence pattern of this cost item.

7. Lost and Unaccounted-for Gas (LUAF) and Company Use

These two items jointly are commonly referred to as shrinkage. Two issues have been discussed in this proceeding:

(1) should shrinkage be collected from sales customers, all customers, or just "distribution-level" customers, and (2) which noncore rate components should include noncore-associated shrinkage?

PG&E, TURN, and DRA propose to allocate shrinkage to total deliveries at both transmission and distribution levels. SoCal and SDG&E propose to allocate company usage to all customers but LUAF only to distribution level. The effect of the SoCal-SDG&E proposal, in contrast to the PG&E-DRA-TURN position, is to have a greater amount of these costs recovered from core customers.

These costs vary directly with gas use. There is conflicting testimony regarding whether gas losses occur only at the distribution level or at both the transmission and distribution level. Until it can be shown that LUAF occurs only at the distribution level, we find that both LUAF and Company Use costs should be allocated to all customers--both distribution and transmission level. Also, these costs are properly recovered in the volumetric rate.

8. Noncore Transmission/Distribution Split

In D.86-12-009, we directed the utilities to present a showing regarding the effect of disaggregating the allocation of costs to noncore industrial users between the transmission level and the distribution level. It was our intent to see if gas levels of service and their related costs were analogous to electric voltage level disaggregation.

PG&E and SDG&E both attempted to comply with the prior direction. SoCal failed to do so, arguing that it had neither a proper definition of "transmission level service" nor sufficient current knowledge of its customers to make such a classification.

CMA and PG&E support the transmission-distribution split on the basis that transmission customers do not benefit from the use of the distribution system. DGS and SoCal, supported by TURN, assert that the distinction is inappropriate.

Upon closer examination we now agree with DGS that service level differentials for gas service are not analogous to service level differentials for electrical service. For electrical service, the customer chooses its level of service according to its own needs, and convenience. Service at the transmission level is offered over a very wide geographic area. For gas service, on the other hand, transmission service is only provided in the very narrow geographic areas where a transmission line is located.

The result of the transmission/distribution level split would be that customers would suffer discrimination based upon geographic location. This proposal may be cost-based, but the purpose of cost-based rates is to send an economic signal to customers so that they can make economically-based decisions. In this case, most customers would have no choice of service level. Where customers have no options to exercise, the need to have rates reflect exact cost incurrence is lost. Although we acknowledge that D. 86-12-009 required such a split, in that proceeding we did not examine this issue in the detail in which it has been studied here. Based upon that closer examination, for the reasons explained above, we will not adopt the transmission/distribution level split in allocating costs to noncore industrial customers.

9. <u>Distribution-Related Expenses</u>

D.86-12-009 allocates 50% of Administrative and General (A&G) costs to customer classes based on average year throughput. D.87-05-046 granted San Diego and Long Beach, as wholesale customers of SoCal, exemption from the allocation of distribution-related A&G. At issue in this case is whether this same exemption should be applied to (1) PG&E wholesale customers and/or (2) other transmission level customers.

We have previously indicated that this issue can be reviewed in future re-allocation proceedings. We will not change our prior decisions on this issue, except as to the application of the exemption to PG&E's wholesale customers. We will apply the exemption of the allocation of 50% of A&G to the wholesale customers of PG&E in the same fashion that we did for wholesale customers of SoCal.

10. Abandoned LNG Amortization

The costs associated with the amortization of the abandoned LNG project are already included in the margin of each utility. The question at issue is: How are the costs to be functionalized, classified, and allocated to the customer classes?

SoCal has functionalized its LNG costs as production-related, while PG&E originally treated its LNG costs as storage-related. In its brief PG&E changed its position to advocate that these costs should be treated as transmission costs. TURN and DRA, on the other hand, support transition cost treatment for these costs. As an alternative TURN points out that treating these as production-related would have the same result, i.e., equal-cents-per-therm. The TURN-DRA proposal is based on the theory that LNG was a "supply" not a "storage" project, and conceptually should be handled in the same fashion as GEDA.

We agree with the PG&E position that these costs should be functionalized as transmission-related. The LNG system was intended to accept LNG, change it back to a gas, and deliver the gas to the transmission and distribution systems. The LNG projects would not have produced natural gas. The amortization of these costs should therefore be functionalized as transmission and allocated using a cold year throughput factor.

11. Interutility Revenues

There appears to be a consensus amongst PG&E, SoCal, DRA, and TURN that any interutility revenues earned (except from affiliates) should be used as an offset to fixed transmission costs. We agree with the consensus position because both the costs and the revenues are strictly transmission-related. Furthermore, these should be allocated on the basis of cold year annual throughput.

12. Storage Costs

The issue here is whether we should change our previous decision to allocate storage costs to both sales and transport-only customers. SDG&E makes a long argument that storage costs should not be allocated to transport-only customers because they do not have control of storage operations. We will affirm our intention to allocate storage costs to all customers because all customers receive the benefits of storage operations.

Hadson raised the issue of what level of storage service the various types of customers should expect, questioning in particular whether the utility should use its storage capability to provide core-elect customers with more reliable service than those that just transport gas. This issue has been set for hearings in I.86-03-036 and will be addressed there. We are hopeful that a decision on this and other storage issues can be issued before the implementation date.

13. Balancing Account Balances (CAM, GCBA, and PGA/SAM)

There are two basic approaches to this problem. The first is to allocate these costs on an equal-cents-per-therm method. The second approach is to allocate these costs on an equal-percent-of-revenues mechanism. The first is strongly favored by TURN, while that second is supported by the utilities and the noncore customers. There is a certain amount of controversy surrounding the calculation of the equal-percent-of-revenues method, but it is clear that no matter how it is calculated the equal-percent-of-revenues method allocates less revenue to the noncore class than does the equal-cents-per-therm method.

At this point, all consensus is lost. Those on each side of this question have attempted to show that it was the other customer group that was responsible for the undercollections. There does appear to be consensus that undercollections related to cost of gas should be allocated on an equal-cents-per-therm basis. However, those particular undercollections can not be isolated because the balancing account mechanism consolidates several different effects (PGA and SAM). We find that there is no way to establish cost causation for the current balances.

Also, it appears that balancing account balances fit our adopted definition of transition costs. Allocating balancing account balances in similar fashion to transition costs will simplify the accounting structure of the new program.

For the above reasons, we will adopt the equal-cents-per-therm allocation method for these balancing account balances. We will therefore not need to discuss the different ways to calculate the equal-percent-of-rates (revenues) allocation method.

B. Revenue Requirement Issues

At this point, most of the revenue requirement issues that were contested have been resolved, i.e., interutility revenues, EOR revenues, and franchise fees and uncollectables. The remaining issues concern balancing accounts and GEDA.

1. Balancing Account Amortization

The amortization for "offset balancing accounts" was somewhat controversial in this proceeding in that there were at least three different periods proposed. PG&E, supported by TURN, suggests a twelve-month period based on the theory that all customers will have experienced one complete annual cycle of usage.

SoCal proposes a nine-month period, with the caveat that it would make an advice letter filing lowering the rates once the balancing account is zeroed out. This is opposed by TURN, who favors a twelve-month period because it will result in a rate decrease.

Finally, Hadson Gas suggests that we tie in the amortization period to the length of time (two years) that the NRSA protection will be in existence. We agree with and will adopt the Hadson proposal. By accepting this proposal we can provide for an extended period of rate stability while at the same time allowing the utilities ample opportunity the recover the balances. Also, the two-year time period is short enough so that it is likely that the customers who created the undercollection will also pay it off.

2. Balancing Account Forecast

Later in this order we establish May 1, 1988 as the date when the rates approved in this order will go into effect. Given this implementation date, we will calculate rates in this order using the latest available CAM and GCBA balancing account forecasts for May 1, 1988. The utilities also should use their latest forecasts in their February 1 advice filings. Because the rates which go into effect on May 1 will be based on forecasted balancing accounts, the utilities should record the actual May 1 CAM and GCBA balances. In their next cost re-allocation proceeding, we will allow them to recover or refund, with carrying costs, the noncore portion of any difference between the May 1 forecast and actual. This will zero out the noncore portion of the current balancing accounts.

3. GEDA

We will adopt the stipulated revenue requirements of $50.0 million for PG&E and $18.4 million for SoCal.

4. Lost Revenue

One additional issue was the concept of estimating demand charge revenues from lost customers. The theory was that some customers who decide to no longer take gas service on or before the implementation date would still incur demand charges which would be assessed based on historical usage. Both the adoption of the TURN forecasting methodology and the way that demand charges are implemented make this a nonissue and no additional revenues will be forecast for this item.

5. Adopted Cost Allocations and Revenue Requirements

At this point, the adopted cost allocations and revenue requirements can be calculated and are shown in the tables below:

V. Core Market Rate Design

We are now ready to complete the calculation of rates that will actually be faced by California customers. As discussed earlier, the first step in this process was forecasting the total throughput expected for each utility. Next, we allocated the fixed costs of each system to the different customer classes based mainly on our throughput forecasts, and calculated the two portfolio prices. We are now ready to take the final step -- assigning each cost item to a particular rate design component and calculating the final rates.

Throughout this decision, we have been careful to maintain the distinction between transmission, the movement of gas, and procurement, the purchase of the actual gas molecules. Our allocated fixed costs will make up the rates for transmission, and the portfolio prices we adopted earlier will be the procurement prices.

For the core market, these two rate components will be combined into a single, bundled rate for both services.

A. Residential Rate Design

1. Customer Charge

Among the utilities in this proceeding, only SoCal presently imposes a residential customer charge. The issues raised during this proceeding concern the imposition of new customer charges, the increase of present customer charges, and the question of whether to include customer charges in the calculation of baseline rates.

The issue of whether customer charges must be considered in the calculation of the baseline rate is so well settled that it requires no further discussion. Our current policy will continue.

Concerning the remainder of the customer charge issues, it is PG&E's position that there should be no change in its residential rate structure at this time because of the regulatory and legislative climate. Translated, this means that because the baseline concept is currently under legislative scrutiny, PG&E believes it prudent to not impose a residential customer charge at this time.

SDG&E proposes to impose a new customer charge of $5 per month. SoCal wants to raise its customer charge from $3.10 to $7.50 per month. These positions are supported by other noncore customers and pipeline companies. The rational is that there are embedded residential customer costs, and that cost-based rates should reflect these costs. In addition, some parties believe that high Tier II rates dampen sales to the core market.

TURN, on the other hand, is opposed to either the imposition of new customer charges or the increase in present charges. In fact, TURN favors the elimination of SoCal's present customer charge. TURN supports its argument by pointing out that:

1. Customer charges result in a greater disparity between Tier 1 and Tier 2 rates.

2. The utilities are already guaranteed 100% of margin recovery because of the core balancing account.

We will adopt the TURN-PG&E suggestion that the status quo be maintained, based upon the reasoning of TURN.

2. Baseline Rates/Allowances

There were two issues of consequence in this area: (1) changing baseline volumes for SoCal, and (2) how to phase in baseline changes for all three utilities.

a. SoCal

Section 739 of the Public Utilities Code requires the Commission to set baseline allowances for gas usage at between 50 and 60% of average residential consumption in the summertime and between 60 and 70% in the wintertime. SoCal has shown that the current baseline amounts are substantially above the statutory range. SoCal proposed the amounts shown below:

Climate Zone	Current	Proposed
Summertime	22	19
Wintertime		
1	72	50
2	94	65
3	125	87

These amounts will result in about 55% of summer residential usage and 67% of winter residential usage being billed at the baseline rates. These amounts were not contested and will be adopted.

The contested issue is over what period of time the changes should be phased in, recognizing that these changes can produce extremely large percentage rate changes for small users. DRA recommended a three-year period. SoCal believes that the allowances can be implemented immediately. TURN was unable to suggest an appropriate phase-in mechanism, but did seem to argue that any rate change caused by a change of baseline allowances be limited to 5%.

The problem is how to implement the changes without causing a rate shock to customers who now use close to the baseline quantity. Because we cannot at this time predict what implementation schedule will minimize rate shock, we will allow SoCal some flexibility in the implementation, subject to the following guidelines. The phase-in period should be no longer than three years. Also, whenever a new revenue requirement results in a rate reduction for the residential class as a whole, SoCal will be allowed to accelerate the three year implementation schedule. Rate increases due to baseline implementation should be capped at 15% above the class average. Thus, if SoCal decreases residential rates by 10%, it may change baseline quantities at the same time to produce residential bill impacts no greater than a 5% increase. SoCal should file an advice letter by March 1, 1988, detailing its plans for any baseline allowance changes to take place with the May 1, 1988, change in core rates. In developing these plans, SoCal should meet and confer with DRA, TURN, and other interested parties.

b. TURN Baseline Adjustment Mechanism

No party contested the continuation of the TURN Baseline Adjustment Mechanism which we have utilized in the recent past. The mechanism will be used for all three utilities. In its comments, TURN correctly notes that, under this mechanism, revenue increases due to reductions in the baseline allowances must be used to reduce the baseline rate. This should be reflected in SoCal's March 1, 1988, filing.

B. Core Commercial Rate Design

1. Large/Small Customer Differentials

The Large/Small customer split is an issue that was raised by several flower growers. The problem is that two commercial customers who are approximately equal in the size of their usage, but only one of whom has alternate fuel capability, will be afforded widely different rates. The customer in the core class, although a very large core customer, would be paying much higher rates than the noncore customer. To the extent that the utilities offer declining block rates to such core commercial customers, the differentials will be lessened. PG&E's proposed rate structure, which was supported by DRA, already incorporates this concept to some degree. We will adopt PG&E's proposed rate structure.

It appears that SoCal has been less responsive to the circumstances of its customers in this regard. Under the present structure, there would be a large rate differential between the core and noncore commercial customers of similar size. The ALJ Ruling of September 9, 1987, requested that the utilities submit rate designs that would mitigate this problem. The SoCal response is indeed a major step in the right direction and will be adopted.

SDG&E appears to support the rates that it filed in response to the ALJ ruling. The SDG&E rate structure will be adopted, since it also mitigates the large rate differentials at issue.

2. Seasonal Differentials

PG&E, with the support of DRA, proposes to extend the seasonal differentiation to core commercial customers as well as noncore customers. The basis of this proposal is to signal that the cost of service is greater in the winter than in the summer. Inherent in the proposal is that certain customers might have some ability to change their usage patterns. It would appear that the proposal is consistent with the position of CMA.

SoCal and SDG&E oppose this seasonal differentiation for core commercial customers on their systems. Their primary reason is that there is no reason to send an such an economic signal when there is no capacity constraint. CH&MA, TURN, and DGS support the position and reasoning of SoCal.

Further, CH&MA argues that the seasonal rates are an unnecessary complication and result in severe winter bill impacts. The severe winter bill impacts result from the percentage differential between the summer and winter rates.

We agree with CH&MA that where there are seasonal rates, the summer/winter bundled rate differential should be no greater than 35% for this initial period. This differential is chosen on a trial basis, and reflects the CM&HA argument that PG&E's proposed rate differentials of about 50% to 60% are too high. We will, however, allow PG&E to place rates into effect with this capped seasonal differential, based upon the fact that winter costs are greater than summer costs. This rate structure should be looked upon as an experiment subject to review.

The ALJ's draft order does not mandate a seasonal core commercial rate for SoCal or SDG&E, because there are no projected capacity constraints. We agree with the DRA's comments that an imminent capacity constraint is not required in order to justify seasonally differentiated rates. Indeed, signalling to customers in their rates when the system is most heavily used will induce them to use the system more efficiently, perhaps postponing any future constraints. We also prefer sending more accurate signals in the rate structure to approving special discount rates targeted only to certain customers, such as SoCal's proposed gas air conditioning and water pumping rates. Thus, SoCal and SDG&E should implement seasonally differentiated commercial rates on the same basis as PG&E. They should include their proposed seasonal core commercial rate in their February 1 filing.

3. Availability of Core Transportation

In D.86-12-009, we mandated that large core customers receive transport service at a high (core) reliability, but that they could seek their own supplies and receive transport-only service. PG&E proposes that we require that these large core customers take their supplies only from the core portfolio. This proposal was also supported by SoCal. PG&E has not shown sufficient reason to modify our previous decision on this point. Large core customers shall retain the ability to choose transport-only service.

4. Special New Rates

SoCal has proposed two new rates for the non-residential core market. The first is a gas air conditioning rate which will be available only to customers without cogeneration facilities. The second is an agricultural water-pumping rate. Both rates are to apply only to new installations; that is, customers with equipment installed after the adoption of the rate. The proposal is strenuously opposed by SCE, which believes that it will suffer a significant amount of load loss to gas service.

We share SCE's concern that the full impact of SoCal's proposal, on both electric as well as gas ratepayers, has not been addressed adequately. This concern is heightened by the fact that SoCal's special rates would apply to all new installations, first-time as well as replacement, whereas SoCal's justification for the rates is primarily to prevent the erosion of the current market for gas in these applications. Finally, we note that these customers will benefit from our adoption of seasonal differentiation for SoCal's commercial rates. This may obviate the need for such special rates. In general, we prefer cost-based rate signals to special rates for certain customers. We will not approve SoCal's request.

VI. Noncore Rate Design -- P2B and Industrial

For the non-core market, we will establish distinct, unbundled rates for transmission and procurement. As we did with the core, the procurement rate will be the applicable portfolio price, although non-core customers have the option of being served from either the non-core or the core portfolio, or of transporting their own gas.

The default rate for transmission will consist of the four components we adopted in D.86-12-009 -- a customer charge, two demand charges (D1 and D2), and a volumetric rate. Calculating the default transmission rates is simply a matter of assigning each allocated fixed cost item (e.g., storage, A&G) to a specific rate design component. For example, we place all franchise fees and uncollectible expenses in the default volumetric rate, and all customer costs (except the part relating to return on equity and associated taxes) in the customer charges. In this way we complete the chain: throughput forecasts are developed and used for allocating fixed costs, and these allocated fixed costs flow directly into specific rate components.

We have already decided much of this final step in previous decisions, and we now turn to the issues that remain to be resolved.

In D.86-12-009, we set forth the noncore default rate structure, composed of a customer charge, two demand charges, and a volumetric rate. Several parties made proposals in this decision to change this default rate structure. Their arguments for the most part offer nothing new. The previously adopted default rate structure will generally be retained.

The most important characteristic of the default rate structure is that it is just that -- a set of rates to be applied when the utility and customer are unable to reach a negotiated agreement. We realized at the time of the previous decision that the default rates would not meet either the needs of utilities or the unique characteristics of many customers. The default rates were designed to be cost-based and available to customers in the event that the utility refused to negotiate meaningfully a different rate.

A. Customer Sub-classes

If we look at the entire body of customers as essentially three classes - core, noncore, and wholesale - then the next level of classification we are interested in is the sub-classes within the noncore class.

The three utilities proposed the following groupings:

PG&E	-	1.	Large P2b
	-	2.	Cogeneration
	-	3.	UEG
	-	4.	Other Industrial Customers
SoCal	-	1.	Propane alternate fuel
	-	2.	No. 2 fuel
	-	3.	No. 6 low sulphur
	-	4.	No. 6 high sulphur

	-	5.	Cogeneration
	-	6.	UEG
SDG&E	-	1.	UEG
	-	2.	Cogeneration
	-	3.	Other noncore

CMA contested SoCal's alternate fuel-based groupings as reflecting value-of-service pricing principles and possibly providing SoCal with a convenient basis for unduly discriminating among noncore customers. We share CMA's concerns, and fail to see what utility the old groupings have in our new rate structure. SoCal should use the PG&E groupings. The PG&E proposal that each of its basic classes be further refined into transmission and distribution levels will not be adopted, as discussed earlier.

B. Default Rate Structure in General

PG&E supports the rate structure adopted in our prior orders, although the utilitydoes not necessarily agree with the cost elements included in portions of the rates. SoCal, on the other hand, prefers to eliminate the seasonal monthly ratchetted demand charge in favor of having the annual demand charge based on three years historical usage. TURN and DGS also support the SoCal view on this point. The SoCal-TURN-DGS position asserts that seasonal demand charges are redundant in light of the priority charge. Further, they argue that seasonal demand charges will encourage peak-shaving at a time when there is excess capacity.

CMA, while preferring to eliminate or at least reduce demand charges, recognizes that if demand charges are to be retained then the combination of D-1 and a seasonally differentiated D-2 is reasonable from a cost allocation and revenue recovery standpoint. CMA argues as follows:

> "It is beyond dispute that those customers which have higher requirements during peak period impose greater costs on the system (Tr.

> 4545). These customers should be responsible for such costs through a seasonally differentiated demand charge. To fail to incorporate such a demand charge means that high load factor customers will be bearing a disproportionate share of seasonal costs. Mr. Cecil's testimony clearly demonstrated that a D-1 and D-2 combination was clearly more cost-effective for high load factor customers (Exh. 235, p. 12)."

We will retain the present basic structure. We remind SoCal and others that their arguments have impressed us that there is a mutual need to negotiate with customers rather than change the default rate structure. For instance, it seems perfectly reasonable that many customers would prefer the rate structure proposed by SoCal, especially if it were designed to be revenue neutral compared to the default structure.

C. Default Rate Components

1. Customer Charges

D.86-12-009 provided that the customer charge proposal of DRA would be the basis for establishing customer charges. SoCal, SDG&E, and DRA have correctly implemented the customer charge concept, which is to have the charge vary by average monthly usage over a twelve-month historical period. The number of bands and the size of the bands, as contained in the latest DRA filings, will be adopted. The new PG&E proposal (unsupported by other parties) to have flat customer charges for all customers in a class will be rejected because it does not reflect costs and does not implement our prior orders.

2. D-1 Demand Charge

In this order we have added a number of items, principally transition cost items but also the balancing account amortization, to the noncore demand charge, compared to the treatment of these costs in the ALJ's draft order. These new demand charge components should be added to the D-1 demand charge.

3. D-2 Demand Charge

As discussed previously, several parties (TURN, DGS, and SoCal, principally) oppose the seasonally differentiated ratchetted monthly demand charge. We have decided to retain this form of demand charge. However, the proposal of DGS that the costs associated with this demand charge be collected in the volumetric rate deserves comment. The effect of collecting these costs volumetrically would be to reduce the incentive for customers to peak shave and at the same time to increase the risk of revenue recovery for the utility. This seems to further illustrate that there are incentives for the utilities and their customers to negotiate rate structures which reconcile each group's particular needs.

4. Volumetric Rate

This was an issue which generated tremendous controversy. The utilities strongly support a small volumetric rate accompanied by large demand charges. The large noncore customers (CMA) and DRA are equally vociferous in support of having a greater proportion of costs recovered in the volumetric rate. In fact, the controversy was really generated by a DRA proposal.

The DRA proposal is to include the following items in the volumetric rate:

1. CAM/GAC balancing account amortization surcharge.

2. Transition costs.

3. Return on equity and associated taxes.

4. 50% of A&G expenses related to sales.

5. Franchise fees and uncollectibles expenses.

6. Lost and unaccounted for gas (LUAF) and fuel use (shrinkage).

DRA is not opposed to moving the first item (CAM/GAC balancing account surcharge) to a demand charge. DRA recognizes that the higher the volumetric rate, the more difficult it will be for the utility to market the gas. This difficulty in marketing gas would be shared with the upstream pipelines and producers. Thus, according to the DRA, with a high volumetric rate there would be an incentive for the utilities, pipelines, and producers to minimize the costs assigned to that rate.

The customers generally support the position of DRA, but with a different motive. The customers attempt first to focus the argument on the cost characteristics of the items in question. CMA argues that most of the cost items are "commodity-related" and therefore should be collected in the volumetric rate. Their second argument is that the presence of high demand charges will place gas at a competitive disadvantage to other fuels. Therefore, the higher the demand charge, the less marketable gas will be. CMA is also of the opinion that the utility must be at risk for the recovery of these costs in order to create an incentive for the utility both to minimize them and to negotiate with customers in a meaningful way.

The utilities, on the other hand, also focus on the cost characteristics of the items by arguing that only variable costs should be recovered in variable (volumetric) charges. Similarly, fixed costs should be recovered in fixed (demand) charges. Failure to do so will result in false price signals and incorrect fuel choices. Secondly, the utilities cite language in D.86-12-010 to the effect that, except for ROE and associated taxes, no other non-variable items should be included in the variable volumetric rate.

The ALJ proposed to adopt the DRA's position, arguing that the increased risk to the utilities due to a high volumetric rate could be shared with upstream participants in the gas flow. He also cited a high volumetric rate as an incentive for the utilities to negotiate the structure and level of rates with noncore customers. Although we share the ALJ's perspective on the benefits of recovering some fixed costs in the volumetric rate, we also feel that we must temper how far we carry this view. We do.

not wish completely to lose sight of the underlying nature of the cost items we are assigning. We are also mindful of the legal requirement that the utilities have a fair opportunity to recover their costs. Generally, we intend to assign fixed cost items to the demand charges, and variable cost items to the volumetric rate. However, we are persuaded that if the default rates removed virtually all risk from the utility, then the utility would be unlikely to negotiate with customers concerning the structure and level of rates. Indeed, the utilities have indicated in strong terms their reluctance to negotiate. The one significant fixed cost item which we do assign, as an incentive to negotiate and to minimize costs, to the volumetric rate -- 50% of A&G costs -- is one over which the utilities have direct control. This follows the principle we have used in deciding the ratemaking treatment of transition costs: demand charge treatment for costs that are fixed and beyond the utility's control, volumetric treatment for those over which the company has influence. Thus, for noncore, nonUEG, retail rates, we will assign the following cost items to the volumteric rate:

1. Company use and LUAF (shrinkage).

2. Franchise fees, the CPUC fee, and uncollectibles.

3. Return on equity and associated taxes.

4. 50% of A&G expenses related to sales.

5. Transition cost items assigned to the volumetric rate, as adopted in Section II.A.3.

D. Start Date for Demand Charges Calculation

This was an issue because PG&E and other parties continue to recommend that the start date for calculating demand charges be the date that service starts under the new rates as opposed to a historical period. We clarified our previous decisions on this point as late as July of this year, in D.87-07-044. The parties have presented us with nothing more than policy arguments and nothing that persuades us to change the position adopted in D.87-07-044, which was:

> "The demand charge calculations for both the D1 and D2 demand charges for default customers after the implementation date will not include usage occurring before the implementation date under schedules that contain no demand charges."

However, one other point requires comment. PG&E continues to show a misunderstanding of their negotiating flexibility under this program in the following statement from their brief:

> "However, the Commission should understand that any negotiated modification to a ratchet already incorporated in the rate design would result in a revenue loss to the utility."

PG&E seems to assume that any modification of the rate structure will result in a revenue shortfall. In fact, the utility and the customer are free to negotiate any rate level and structure on which they can mutually agree, including specific rate components that are higher than the corresponding components in the default structure. The default rates are designed to be available to customers that can not successfully come to terms with the utility.

VII. UEG Rate Design

The UEG customer class is unique among the gas utility customer classes. The UEG class is such a large portion of total demand for gas that a ripple in the electric fuel mix decisions can be a tidal wave for the gas utilities. The lack of diversity in the UEG class may very well justify a different rate treatment than for the other noncore industrial customers. During the course of this proceeding, several issues arose around the UEG rates. The most sensitive of these are the structure of the demand charges and the construction of the volumetric rate component.

A. UEG Rate Structure

1. Demand Rate Structure

The issue here is whether the UEG customer should have the D1-D2 structure based on historical usage, or a fixed demand charge based on forecasted annual usage. Because of the possible underrecovery of revenues if ratchetted D1-D2 demand charges are based on historical usage, t e gas utilities are united in their position that the demand charge should be on an annual forecasted basis. This position is also supported by TURN, which envisions major powerplant dispatching problems with a rate structure similar to the one adopted for other noncore customers.

DRA favors a rate structure identical to its proposal for other noncore customers. SCE favors the DRA proposal; it sees no need to treat UEG customers differently from other noncore customers. The DRA proposal is based on the same foundation as its proposal for other noncore users; i.e., greater risk is placed on the gas utility in order to create cost reduction incentives.

SCUPP is a UEG customer with a different view. It favors the forecasted fixed annual demand charge because it allows a greater degree of certainty for both the gas utility and the UEG customer.

We will adopt the fixed, forecast annual demand charge for the UEG customer class, because of the risks associated with the lack of diversity in this class. Also, this form of the rate will allow more rational fuel mix decisions for the UEG customers. This annual rate will be collected monthly in proportion to forecast monthly sales to the UEG customer class.

2. UEG Volumetric Rate

It is this component of the rate that causes the gas utility the most concern. The basic arguments concerning what cost items to place in the volumetric component of the UEG rate are the same as the arguments made concerning this issue for other noncore customers, as discussed earlier. The bottom line is risk incurrence; the higher the proportion of costs included in the volumetric charge, then the higher the risk assumed by the utility. As revenue recovery is shifted from the volumetric rate to the demand charges, risk will be shifted from the utility to its customers. D.86-12-009 provided that the volumetric rate would include:

1. Fuel use.
2. Line losses.
3. Franchise fees.
4. Return on Equity (ROE) and associated taxes.

In D.87-02-029, in response to a request by PG&E, we revisited this issue as it applies to UEG customers. In that decision we excluded ROE and associated taxes from the transmission volumetric rate for combination utilities. In a subsequent decision (D.87-05-046), responding to a plea from SoCal Gas, we modified the rate structure for SoCal. The modification was to transfer 75% of the ROE and associated taxes from the volumetric to the demand charge portion of its UEG rate.

In this proceeding, DRA was generally supported by SoCal's UEG customers in proposing transfer of several cost items from the demand charge back to the volumetric rate. As with its position on the volumetric rate for other noncore customers, the DRA's reasoning emphasizes risk placement and the creation of incentives rather than cost characteristics. In addition, there are new classifications of costs, such as transition costs, that we have not reviewed in prior orders.

We will modify slightly our prior orders concerning which cost items to place in the UEG volumetric rate. In this proceeding we have taken a much closer look at the utilities' detailed cost structures. We have also defined, calculated, and provided for the recovery of transition costs, a cost category that was a significant unknown at the time of our prior orders. The bulk of current transition costs will be placed in amortization accounts and recovered in demand charges. The resolution of this major issue makes it an appropriate time, in our view, to make some "fine-tuning" adjustments in the amount of risk we have placed on the utilities. As we have discussed previously, we concur with the DRA, CMA, and others that placing some significant fixed cost items in the noncore volumetric rates can create the proper incentives for the utilities, both to minimize costs and to negotiate meaningfully with customers. However, we have noted that these incentives are fair to the utility only if the fixed costs placed in the volumetric rate are those over which the company has some control. For this reason we placed 50% of the A&G costs into the volumetric rate for P2B and industrial noncore customers. We will modify our prior orders to also place this cost item in the UEG volumetric rate. We have also assigned several transition costs to the volumetric rate; these will be included in all noncore volumetric rates, including UEG rates. We will not modify our prior treatment of ROE and taxes in UEG rates. This treatment adequately recognizes the difference between combination and gas-only utilities, and reflects, when compared with the volumetric rate for other noncore users, the greater volatility of UEG sales. Thus, the UEG volumetric rate will include:

1. 25% of ROE and taxes for SoCal only.

2. 50% of A&G expenses related to sales.

3. Variable costs (shrinkage, CPUC fee, franchise fees, and uncollectibles).

4. Transition cost items placed in the volumetric rate, as adopted in Section II.A.3.

B. UEG Overrun Rate

SoCal proposed an "overrun rate". The concept is that there is a possibility that forecast UEG demand can have a wide variation from actual demand. SoCal proposed a special rate whenever actual takes exceed 110% of forecasted takes. No other parties supported this concept. This seems like an ideal subject for negotiation, just as does the possibility of a tiered UEG rate. We will not mandate this overrun rate as a part of the default rate at this time. We want to gain some experience with our new structure before mandating such detailed rates in the default rate structure.

C. Cogeneration Shortfall

This item will be resolved in a following section on cogeneration rates. In that section we will discuss the cogeneration rates and allocation of any resulting shortfall.

D. Igniter Fuel Status

Only PG&E raised this as an issue. Its recommendation is that this type of fuel, currently classified as P2A, be classified as core for transportation. This usage fits our basic definition of core service - no alternate fuel capability - and will be classified as core service.

VIII. Cogeneration Rates

There were essentially two different points of view regarding cogeneration rates in this proceeding. The first is represented by PG&E and SDG&E; the second by SoCal and DRA. The first proposal by PG&E maintains a separate cogeneration class and attempts to implement a "similar terms and conditions" rate parity mechanism. One key to this mechanism is a distribution-level adder; that is, cogenerators taking service at the distribution level would pay an additional charge to bring the rate up to the UEG rate at the transmission level. Basically, the PG&E/SDG&E approach is a more detailed look at the rate parity concept. PG&E

would only allow core cogenerators to receive service at their core-equivalent margin rate.

The DRA proposal is a more simplified approach. The proposal is that for each customer the utility would calculate the bill under both the otherwise applicable industrial rates and a UEG average rate. The customer would pay the lower of the two bills. The UEG average rate would be the total fixed and variable charges charged to the UEG customers in a given month, divided by total usage during the same month. This total average rate would then be available to the cogeneration customers. There would necessarily be a true-up period of 60 days.

The SoCal proposal is somewhat similar. It would in essence "roll in" cogeneration customers into the UEG class. SoCal proposes to convert the fixed UEG demand charge to a cents-per-therm figure by dividing by forecast UEG volumes. The resulting rate would be charged as a demand charge to cogeneration customers based on the 36-month historical average consumption of the individual cogeneration customer. SoCal would charge cogeneration customers the same volumetric transmission rate as charged to UEG customers. Transmission rates charged to all cogeneration customers would be the same. For procurement, noncore cogeneration customers would have the same options as UEG customers and core cogeneration customers would have the same options as core UEG usage.

Several of the cogeneration customers support both the DRA and SoCal proposals. In deciding which approach to adopt we are mindful of our statutory obligation to "establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electritity." (P.U. Code Section 454.4). Section 454.4 clarifies that the cogeneration parity rate applies only to that amount of gas which would be required to produce an equivalent amount of electricity. In the past, we have implemented P.U. Code Section 454.5 by setting cogeneration gas rates at parity with average UEG rates. Moreover, we have treated all cogeneration customers equally, making no distinction based upon the costs to the utility to serve different size cogeneration projects because there is no provision in the statute for such discrimination.

We find that the DRA approach best meets the statutory requirement for rate parity. It is simple, understandable, fairly easy to implement, and we will use it in part as a model to guide our adopted approach for setting cogeneration rates. Because we make some changes to the ALJ's proposed decision, we will clarify our adopted approach.

For transmission service, the utility will calculate two bills for each cogeneration customer, one applying the average UEG rate and one applying the otherwise applicable industrial rate. The customer will pay the lower of the two bills. The average UEG rate would be the total fixed and variable charges charged to the UEG customers in a given month, divided by total usage during the same month. The total average rate would then be available to the cogeneration customers. There will necessarily be a true-up period of 60 days.

For procurement service, cogenerators will face the same procurement options available to all customers. Noncore cogeneration customers will have the same procurement options as noncore UEG customers. Core cogenerators will have the same options as UEG core usage and, to the extent such customers qualify under the conditions established by this order to elect noncore procurement service, will have the ability to select the full range of noncore procurement options.

We find that by adopting this structure for cogeneration rates we continue to meet our statutory obligation under P.U. Sect. 454.4 to set cogeneration rates at parity with UEG. For transmission service, cogenerators will have the option of paying a trued-up UEG transmission rate or their otherwise applicable rate. In addition, whenever cogenerators choose to buy gas from the noncore portfolio or choose core-elect service they will face the same cost of gas (either the noncore or core portfolio WACOG) as UEG customers making the same procurement choice. Therefore, cogenerators will receive rate parity with UEG customers whenever they buy gas from the utility.

Only when cogenerators or UEG customers exercise their noncore procurement option to buy gas independently of the regulated utility service will the Commission be unable to guarantee procurement rate parity. Unlike transmission service, we will not adopt a true-up mechanism for procurement costs. The industry structure model which guides this rate implementation decision holds that, with the exception of the noncore portfolio and our approval of a core-election mechanism, noncore procurement service choices and costs are transactions no longer to be regulated by this Commission. Cogeneration customers face the same procurement options as UEG customers and are free to contract as they wish for gas supply. We do not adopt a true-up mechanism for procurement costs because we decline to establish rates for a service which we will no longer regulate.

For all customers paying an equivalent priority charge, cogeneration customers will remain at the P3A priority level. Other customes may gain a higher level of transmission priority by paying a higher priority charge. Similarly, cogeneration customers can bid up their service level by paying a higher priority charge.

Finally, we will adopt the SoCal proposal to move cogeneration customers into one UEG/Cogen customer class. The result of this is that there is no "cogeneration shortfall". One of the problems associated with this result is that a single customer will have usage in two customer classes. This may present problems for future cost allocation studies. However, we are confident that the utilities can overcome these problems.

IX. Wholesale Rate Design

For wholesale customers, we expect that there will be a rate negotiated between the utility and the customer. In our prior decisions, we did not specify a rate design for wholesale customers because of our strong belief that the rates would be negotiated. Quite frankly, we had in mind that the existing arrangement between SoCal and SDG&E would continue, and would serve as the model for other wholesale rate structures.

However, virtually all the affected parties desired a default rate structure. The major concern is that the primary utility will not negotiate in good faith or come to terms in a timely fashion. There was no controversy over whether the default rates should be set at 100% of the embedded cost. We will adopt that particular guideline for wholesale customers as we have done for all other noncore customers. We will also extend to wholesale customers the same treatment that we afforded UEG customers with respect to the demand charge. That is, the demand charge will be set based on forecast sales and paid monthly in proportion to forecast monthly sales.

The real controversy once again is the level of the volumetric rate. The general consensus is that the wholesale volumetric rate should be very low and should bear some relation to the UEG volumetric rate. We agree. Of course, the volumetric rate will include the variable costs applicable to wholesale customers (shrinkage and franchise fees). Concerning the fixed costs in this rate, the SoCal proposal that 95% of the fixed costs should be included in demand charges is a good starting point. However, our inclusion of some fixed and transition costs in the noncore volumetric rate will result in a UEG volumetric rate higher than anticipated by the gas utilities. We will not specify which fixed costs will be included in the wholesale volumetric rate, but will instead provide that the fixed costs assigned to this rate must be within a range. The top end of this range will determine the default wholesale volumetric rate; the default rate will include the fixed costs assigned to the UEG volumetric rate (25% of ROE and taxes for SoCal, 50% of A&G, and the adopted volumetric transition costs). The bottom of the range is defined as 5% of all costs assigned to the wholesale customer, except variable costs. Since the presence of balances in the wholesale balancing accounts could theoretically result in negative volumetric charges, we will mandate that these balances be cleared with a one-time lump sum payment.

X. Non-Rate Related Items

While the focus of this proceeding was on establishing a revenue requirement and default rates, there was also a host of non-rate related items, many of which will be considered in the gas procurement I.87-03-036. The specific items deferred from this proceeding deal with the operation of storage--level of service, load balancing parameters--and out of area brokerage fees.

A. Wholesale Procurement Flexibility

Palo Alto proposed that the wholesale customers be allowed wide latitude in electing into core procurement and also in renominating or changing their nominations. Designating load election actually involves both transportation and procurement. Palo Alto agrees that if adjustments in its transportation nominations require additional facilities, then the wholesale customer could be required to give adequate advance notice. Also, Palo Alto agrees that its proposed latitude in nominating load into the core be restricted to P1, P2A and P2B priorities.

Since there is such a large amount of agreement on these issues, we favor a more hands-off approach. The parties have historically concluded successful negotiations on subjects with the same degree of complexity. We will allow this practice to continue with only a general guideline. The guideline is that if wholesale customers designate less than their high priority load as core procurement, then they must provide at least a one-year notice to shift this high priority load back into the core portfolio. As TURN reminded us in its comments, such shifts will be subject to the portfolio switching policies adopted in D. 86-12-009 and D. 86-12-010. We will allow the parties to negotiate such things as adjustments, growth, and prorations. For transportation designation, we will adopt the rule proposed by Palo Alto. We will let the parties negotiate concerning the true length of time to construct required new facilities.

B. Termination Fees for Core Elect

This issue concerns the cost that might be imposed on core customers if core elect customers take less gas than their contracts specify. The termination fees will be based on forecasts of these costs. TURN wants us to determine who will pay if the actual additional costs vary from the forecast. We will not decide this issue, which was raised only by TURN, because at this time it is too premature and too speculative to either specify a method to quantify the potential discrepancy, or to decide who should bear it. We have zero knowledge at this time of what might cause such a discrepancy. Clearly, it is still our intent that the customers who contract for core elect service must be responsible for the excess costs which they may impose if they fail to meet the terms of that agreement. The utilities will bear a heavy burden in justifying the shift in such costs to other ratepayers.

C. Noncore WACOG True-up

This issue arises because the utilities will charge the price of spot gas for noncore procurement. The utility must post this price in advance but will not know the month's actual spot price until sometime later. It appears that there was agreement among the parties that the utilities could track the adjustments and include them in the next forecast posting. With frequent posting and fairly good forecasting the adjustments should never be large. The critical issue from the customers' and competitors' points of view is that the adjustments should not be applied retroactively for past usage.

D. EOR Revenues

All parties generally agree that D.87-05-046 settled the issue that EOR revenues will be given balancing account treatment. The revenues will be forecast, allocated and then trued-up with a balancing account.

PG&E was unsure of the treatment for short-term EOR contracts signed before December 3, 1987. These revenues should be handled in the same manner as all other EOR revenues. Also, PG&E is correct in its interpretation that procurement revenues, interutility costs, and short-term variable costs are not included in the revenue sharing provided by the EOR balancing account.

E. Pipeline Demand Charges

Because pipeline demand charges are to receive special treatment for allocation purposes, which will produce a relatively flat allocation factor, and because these charges may become more difficult to forecast in the future, the utilities propose that they be afforded balancing account treatment. SoCal recommends that they be included in its proposed balancing account for transition costs.

We disagree. If the utilities feel that they bear excessive risk due to the heavy allocation of pipeline demand charges to the noncore market, the best solution from our perspective would be for the utilities to work out an arrangement whereby they could assign a portion of their firm interstate capacity, with its attendant costs, to noncore customers. There are clearly many industrial, UEG, and wholesale customers who are very interested in pursuing such an arrangement. Although there are currently barriers at the federal level to such brokering of capacity, we have pledged to work to facilitate such an arrangement, in the ongoing I. 86-03-036. With respect to the problem of forecasting pipeline demand charges, D. 86-12-010 (pp. 148-150) has already provided for a tracking account which will reconcile forecasted and actual pipeline demand charges. We will not adopt any further guarantees for the recovery of these costs.

F. Rate Discounting at the NRSA Limits

This issue was primarily argued by TURN. The TURN position is that the utility should be prohibited from any rate discounting if the NRSA limits are reached. It bases its argument on the concept that utility rate flexibility is inconsistent with balancing account treatment. TURN notes that after the NRSA limits are reached, the discounts would be made with ratepayer funds. SoCal argues that if the NRSA limits are reached, then an immediate expedited proceeding would be required to correct rate design problems.

We tend to agree with the SoCal argument and will decline to resolve this issue at this time. If the NRSA limits are reached, we would be willing to re-examine at this issue.

G. Line Extension Allowances

The utilities currently calculate a free footage line extension allowance based on total revenues. PG&E proposes to exclude procurement revenues from the calculation. SoCal is opposed, based on a legal argument that procedural requirements to change these allowances found in Code Section 783(b) have not been satisfied. We will not adopt PG&E's proposed change.

H. Demand Charges - Force Majeure

CMA spent considerable time arguing for relief from customer and demand charges when a customer's gas requirements are reduced due to a force majeure condition. A great portion of this effort was an attempt to have the definition of force majeure expanded or otherwise altered to include reduced takes due to planned maintenance and similar outages, even crop failure.

The utilities understandably argue for a narrow definition. Also, they oppose forgiving demand charges due to planned maintenance and similar circumstances.

The default rates are designed to apply to a wide range of circumstances, and in our judgement should not include a detailed declaratory judgement of all circumstances that could arise under a force majeure exception. We note that if a customer has particular needs or circumstances then the special conditions of service should be ripe for negotiation. We also think that the force majeure conditions in the utilities' existing long-term contracts represent appropriate conditions for the default contracts. As CMA notes, demand charges have essentially replaced the take-or-pay provisions in those contracts. The force majeure conditions in those contracts were the result of extensive discussion among the parties to I. 84-04-079, both before and after D. 85-12-102. We also see no reason to modify the 30-day notice requirement for scheduled maintenance shutdowns, which was adopted unopposed in D. 86-12-010.

I. One-Year Obligation for Demand Charges

D.86-12-009 was clear in providing that the noncore default customers would be obligated for demand charges for a one year period. The remaining issue is whether customers taking no gas on the "implementation date" should also incur demand charges for a one-year period based on historical usage. As a matter of policy, given the notice we provided in D. 86-12-009, we believe that it is fair to adopt the following approach: customers not taking gas for the year prior to the implementation date will not incur demand charges until they begin to take gas.

J. Meter Aggregation

This issue concerns whether a customer with multiple meters or delivery points should be able to to have them aggregated into one for purposes of rate administration. In D.86-12-010, we allowed certain aggregation of services through multiple meters on one facility and requested further discussion of the definition of facility. The issue is substantially effected by our definition of core/noncore service.

The utilities have long standing definitions of what constitutes a facility. DGS proposes a more liberal definition so as to allow further aggregation to expand the options of customers with multiple service points to places that are in close proximity to one another and owned or controlled by the same party. The utilities propose to retain their existing definitions. DRA generally opposes the DGS proposal also.

We believe that there should be some experience gained under the new system -- particularly with the new customer class definitions -- before re-examining the utilities' long-standing definitions of what constitutes a facility. We will not adopt the DGS proposal.

XI. Existing Long-Term Contracts

We have previously approved a number of long-term contracts for gas transmission that were not based on our new gas industry structure. Several questions have arisen concerning the treatment customers holding these contracts should receive following implementation of this decision. We will now resolve these issues.

U.S. Borax raised two issues related to the changes made by the new program and their effect on existing long-term contracts. The first concerns the priority level within the existing contracts after the implementation of our new priority system. The other concerns the allocation of transition costs to customers operating under long-term contracts. Our discussion below will center around the presentation of U.S. Borax although we realize that the outcome of our decision will effect all other similarly situated customers.

We will also make one final modification in the structure of the default UEG rate, to address further the risks which the gas utilities face from potential swings in UEG sales. We will mandate that the default UEG volumetric rate be structured as a two-tiered rate, just as the current SoCal UEG tariff is structured. The lower Tier II rate will contain all of the above cost items, except that we will put only one-half of the A&G cost item (that is, one-half of the noncore portion of the 50% of A&G costs which we have allocated on the basis of annual throughput) into the Tier II rate. The remaining one-half of the A&G costs assigned to the UEG volumetric rate will be recovered in the Tier I volumetric rate. The size of the tiers should follow the current tariff. We note that for SoCal this results in a Tier II rate of $0.15 per MMBtu, which is exactly the current Tier II rate and the Tier II rate recommended by Edison in this case. We feel that such a default rate structure has several advantages. It will keep the UEG incremental gas cost low, to increase the competitiveness of gas with respect to other fuel sources for electric generation. It will reduce the utilities' risk from swings in UEG usage. Yet it will also keep enough costs in the UEG volumetric rate to provide a meaningful incentive for equitable negotiations: we note that the current tariff was essentially the result of negotiations between SoCal and Edison, and appears to have functioned well for the past 18 months.

A. Priority Level

U.S. Borax entered into a long-term transportation agreement with PG&E in August 1986. The contract relied on our existing priority scheme at the time which covered both transportation and supply in a bundled manner as shown in the following quote:

> "The assigned priority shall be the same as the Priority which the customer would receive under the customer's otherwise applicable rate schedule."

In our prior decisions, we indicated that we would not disturb the existing contracts. The question now before us is that although we do not mandate a change in the current contracts, does our changing the priority scheme indirectly effect the contracts to a greater extent than desirable? In contrast to the proposed decision which based its treatment of existing long-term transportation contracts on equity concerns, we find U.S. Borax's arguments persuasive.

U.S. Borax proposes that we "grandfather in" the priority scheme at the time so that customers with long term contracts can enjoy the same degree of security without paying a separate "priority charge". U.S. Borax contends by paying a bundled GC-2 transportation rate, it is paying an unquantified portion for an embedded capacity priority. The specific mechanism is to give all customers with existing long-term contracts:

> "a capacity priority that is higher than the priority of : (1) any customer electing to pay a priority charge that nevertheless pays a lower overall transmission rate; and (2) any default customer or any other noncore customer that does not pay a priority charge."

This proposal would place the long-term contract customers just ahead or equal to default customers not paying a priority charge even though the default rate is likely to be much higher than the long-term transport customer's rate. Also, this proposal would likely place long-term transport priority ahead of other so-called "incremental" customers (EOR). The long-term customer would likely be ahead of default customers that pay no priority charge and other customers that pay a total rate (transport + priority charge) less than the long-term contract rate (3.5 cents per therm for example).

Another proposal was put forth by CMA; however, it was made in light of its own priority scheme. Basically, it would provide that the long-term contract customers would be placed at the same priority level with other default customers. The curtailment scheme would then be governed by the existing end use supply curtailment scheme. Incremental customers with a lower transport rate could bid ahead of the long-term contract customers with a small priority charge. Thus the incremental customer could have a higher priority while still paying a lower overall (transport + priority) rate.

By giving existing long-term transport customers the same priority as default customers, the proposed decision essentially rejects U.S. Borax's argument that its bundled transportation rate includes a real, though unquantified, charge for priority. Although we find the question of whether U.S. Borax is paying a portion of their bundled transport rate as a premium for capacity somewhat ambiguous, we will resolve this ambiguity in favor of existing long-term transportation customers.

We are persuaded that U.S. Borax relied on the contractual provision found in the GC-2 tariff stating that the contract would not be subject to modification in entering into a long-term transportation agreement with PG&E in August, 1986. U.S. Borax also refers to our initial decision adopting long-term transportion in December, 1985, where we stated that future modifications to the program will not affect the terms and conditions of the contracts. It is our intent today, as it was in December, 1985, to give contracting parties the benefits of their bargain. In this regard, we are especially sensitive to the concerns of those who signed up under the original five year transportation contracts. Accordingly, we will adopt U.S. Borax's proposal and grant all customers with existing long-term contracts a capacity priority higher than the priority of: (1) any customer electing to pay a priority charge that nevertheless pays a lower overall transmission rate; and (2) any default customer or any other noncore customer that does not pay a priority charge.

Conversely, any customer paying a priority charge under the priority bidding mechanism that pays a higher overall transmission rate than an existing long-term transport customer would have higher priority than that existing long-term transport customer. In this case, existing long-term transport customers have the option to voluntarily ensure their level of priority by paying an additional priority charge.

B. Transition Charges

The same type of argument is made regarding the imposition of transition charges. That is, any additional charges not envisioned in the original contracts cannot be imposed at this time. We will again not get into an analysis of the contracts in detail, but will attempt to place these customers in the same position as if we had not adopted this new regulatory program for the initial term of their contracts. What they do not pay in transition charges will be considered part of the revenue shortfall allocated to all other customers on an equal cents per therm basis.

XII. Implementation Strategy

This opinion up to this point has developed the revenue requirement, allocated the requirement to the classes, and calculated rates. The rates that are contained in this decision are illustrative at this point in time. We recognize for instance that several events are imminent which could have an effect on the rates contained in this decision. There are underway several proceedings that are going to have an effect on the revenue requirement of the utilities involved in this case.

In addition to the above, several other factors lead us to consider how we might implement the new program with the least amount of abrupt sudden changes as possible. Several of the industrial customers, most notably the CMA, have requested that there be a lengthy amount of time to prepare and negotiate contracts with the utilities. Core customers require a degree of rate stability. Changing core rates during a period of peak usage -- winter -- produces signals that are exaggerated. The baseline season changes on May 1 of each year.

Based on the above considerations it is reasonable to implement new rates on May 1, 1988. In order to put new rates into effect on May 1, 1988 and give noncore customers adequate advance notice, we will adopt illustrative rates that would be effective May 1, 1988 and provide for a formula as to how the rates will be calculated that are actually to be placed into effect on May 1, 1988.

As stated before, the rates contained herein are illustrative. The only differences between the rates adopted herein and the ones to go into effect on May 1, 1988 are that the rates to go into May 1, 1988, will recognize the following:

1. Revised revenue requirements adopted in proceedings that are currently underway and which will be completed (decision date) before January 1, 1988.

2. The balancing account estimates for May 1, 1988 based on recorded information as of December 31, 1987.

The process is that the utilities will make advice letter filings no later that February 1, 1988, which recognize the above changes. The rates contained in the advice letters should go into effect May 1, 1988. The consolidated balancing accounts will be maintained until the "implementation date" which is May 1, 1988.

On this date the "cut-over" will take place i.e., the portfolios will be split and the balancing account balances will be assigned to the classes as provided in this order.

Thus, it should be clear that rates will not change until May 1, 1988. The effects of any revenue requirement changes that take place before the implementation date will be flowed into the consolidated balancing accounts.

ORDER

IT IS ORDERED that:

1. The three respondent utilities to this proceeding, Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas and Electric Company, shall file the following consistent with the intent of this decision:

   a. Proposed cost allocations.

   b. New balancing account balances.

   c. New rate schedules.

2. The above filings made ~~be~~ made in the form of advice letters. The filings shall be made in time to allow the rates to go into place on May 1, 1988.

3. All petitions for modification or rehearing not yet acted upon and to the extent not granted or denied in this order are denied.

4. All motions not previously address are denied.

This order is effective today.

Dated DEC 9 1987, at San Francisco, California.

I will file a written concurrance.

Frederick R. Duda
Commissioner

We will file a written concurrance.

John B. Ohanain, G. Mitchell Wilk.
Commissioners

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser, Executive Director

I.86-06-005 et al.
D.87-12-039

JOHN B. OHANIAN AND G. MITCHELL WILK, Commissioners, Concurring:

We support today's decision because we believe it moves us along a path to achieve our goal for regulating the gas industry in California. As we see it, that goal is to use our authority to set reasonable utility rates and conditions of service to promote the competitive viability of the noncore gas market while maintaining adequate protections for customers who lack competitive alternatives. We are confident that today's implementation decision puts in place a program which is basically sound, that the annual cost allocation proceedings provide sufficient flexibility to modify the program over time as we gain experience with the market, and that the NRSA mechanism provides the utilities with sufficient revenue protection to avoid severe financial harm.

However, we are concerned that, due to decisions reached prior to our participation in the Commission's restructuring of the gas industry, this decision is based on market assumptions which may jeopardize our overall goal. We therefore intend to monitor the success of this program very carefully. We wish to make clear our intent to all participants that in the future we will not hesitate to revisit the basic premises and mechanics of today's order, including the adopted allocation factors, if we find inadequate progress towards achieving the Commission's goal.

JOHN B. OHANIAN, Commissioner

G. MITCHELL WILK, Commissioner

December 9, 1987
San Francisco, California

I.86-06-005
D.87-12-039

FREDERICK R. DUDA, Commissioner, concurring.

I concur with the majority in this case and firmly believe that the decision reached will place California utilities, end-users, and serving pipelines and producers in a sound position to engage in healthy competition.

I am, nonetheless, somewhat concerned about the record and analysis which support the allocation factors used in this case. Accordingly, I believe the Commission can make more informed decisions on revenue allocation and rate design, given an updated record and more complete marginal cost data. The allocation of fixed and variable costs both among customer classes and between demand and volumetric charges pose critical decisions for the Commission; with a marginal cost (or value) basis to guide these allocations the Commission can more rationally define how these costs should be allocated. This will provide a more sound and rational basis for structuring a competitive gas policy framework for California. Moreover, such action will strengthen our gas competition plan, improve our policies, and provide important underpinnings for our program.

A specific example of my concern regards A&G costs. While some portion of the A&G costs are allocated on the same basis as O&M costs, the other portion of A&G costs are allocated on an equal cents per therm (roughly 50-50%) basis. It appears that this allocation is not marginal cost based. I support the proposed compromise of Commissioner Vial to provide a two tiered UEG pricing structure that allocates less A&G expenses to the second tier. I also believe the record in this case leaves little basis for understanding how this policy relates to a marginal cost based rate design.

Furthermore, I believe that some amount of less expensive gas may not come in to California. Likewise, some amount of more expensive alternative fuels may be used as a result of allocating 50% of A&G expenses to the noncore volumetric rate. This translates to a reduction in gas and inter-fuel competition in California; admittedly very difficult to quantify. Yet, defining the advantage in bargaining position provided to customers (by having a higher volumetric rate and greater risk on utilities), and the possibility that customers might in fact negotiate lower gas rates thereby, is very difficult. Judging the risks and benefits of these two approaches, it is unclear as to which approach is distinctly more advantageous. For these reasons I can embrace the Vial compromise.

I strongly urge our LDCs to vigorously pursue the marginal cost studies we have requested in recent decisions so that the Commission, indeed the gas industry, can form a more rational policy of revenue allocation, rate design, and unbundling of gas related services. This is essential to the soundness and success of the new gas policy framework which we set forth for implementation today.

Frederick R. Duda

Frederick R. Duda, Commissioner

December 9, 1987
San Francisco, California