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Decision 92-12-058 December 16, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Order Instituting Investigation on the Commission's own motion into implementing a rate design for unbundling 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 Application 87-01-037 Application 87-04-040

(See Appendix A for Appearances.)

INDEX

I N D E X

OPINION

Summary

This decision adopts a long-run marginal cost (LRMC) methodology[1] for the three respondent gas utilities: Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and San Diego Gas & Electric Company (SDG&E). This marks the first time the Commission has approved a marginal costing method for gas utilities. LRMC is a valuable tool for rate design as well as making efficient capital investment decisions. Marginal cost information is also useful in evaluating bypass and demand-side management (DSM) proposals.

We move forward with today's LRMC methodology recognizing the evolution of the natural gas market in California requires that utilities must charge rates that more closely approximate the marginal costs of service. Customers served by PG&E and SoCal have substantial opportunities for bypass. We acknowledged the magnitude of the bypass threat by issuing D.92-11-052 to enable PG&E and SoCal to use an expedited contract approval process. The LRMC figures adopted today will be used in conjunction with our EAD process to evaluate requests for non-customer specific contracts.

Today's order does not implement specific rates or provide unbundled service costs. We will implement today's policies and establish customer rates in an expedited proceeding for the three utilities in 1993. As part of that proceeding, parties are invited to present proposals to further segment industrial class rates based on service level cost distinctions. SoCal will have the opportunity to segment its distribution system

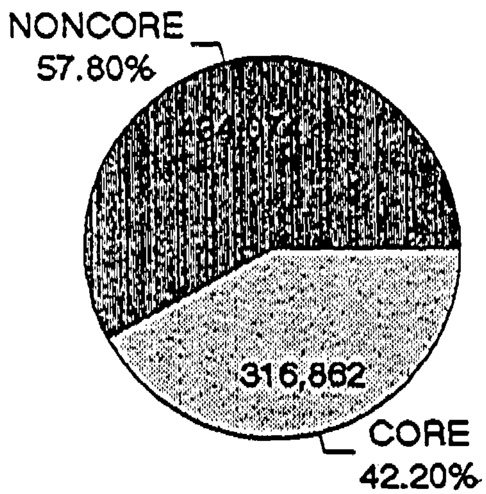
1 Long-run marginal cost captures the cost of the addition of new cost-effective facilities to the system.

into high- and medium-pressure components similar to PG&E's local transmission and distribution system segmentation. If a decision in the Storage OII (I.87-03-036) authorizes SoCal to unbundle its storage services, SoCal will be allowed to present a subfunctionalization of its storage facilities combining the factual findings in the storage proceeding with the methodology adopted in this decision. Finally, wholesale customers will be allowed to show that they would be unfairly harmed by applying Equal Percentage of Marginal Cost on a total factor basis and that EPMC for wholesale customers should be done on a functional basis.

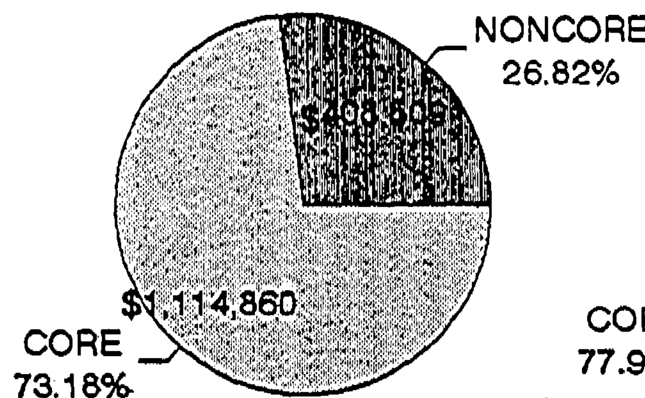
We will address the issue of de-averaging core rates in the next BCAPs for all utilities. This involves separate cost allocations and class definitions for core residential and core non-residential classes, which are currently charged identical rates. We prefer to review resource planning in general rate cases and LRMC methodologies in cost allocation proceedings.

We adopt measures of demand responsibility that in our view best reflect the complexities of cost causation on integrated utility systems. The demand measurements of cost responsibility for transmission, storage, and distribution service are summarized in Table 1, Section 2.3.6. The illustrative rate effect of the policies we adopt today is found at Appendix C. Following are a graphic display of the marginal cost revenue responsibilities for PG&E, SoCal and SDG&E:

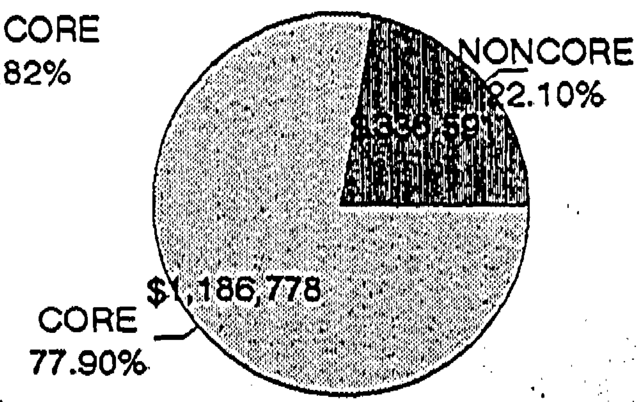
PG&E REVENUE RELATIONSHIPS



AVERAGE YEAR THROUGHPUT
(mth)



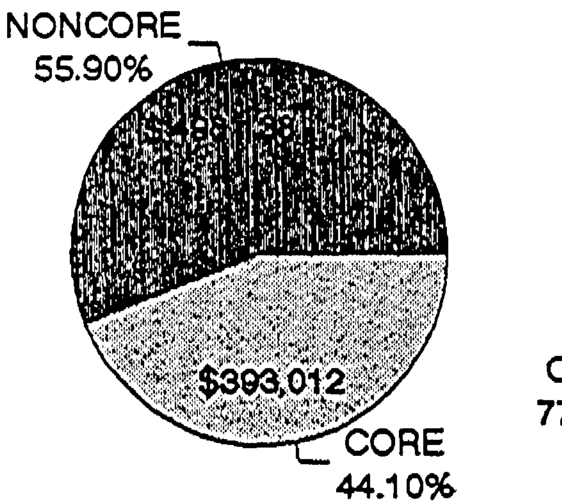
EXISTING REVENUE
RESPONSIBILITY
($000)



ILLUSTRATIVE
REVENUE RESPONSIBILITY
UNDER MARGINAL COST
($000)

I.86-06-005 et al. COM/JBO/rcl

SOCAL GAS REVENUE RELATIONSHIPS



AVERAGE YEAR THROUGHPUT
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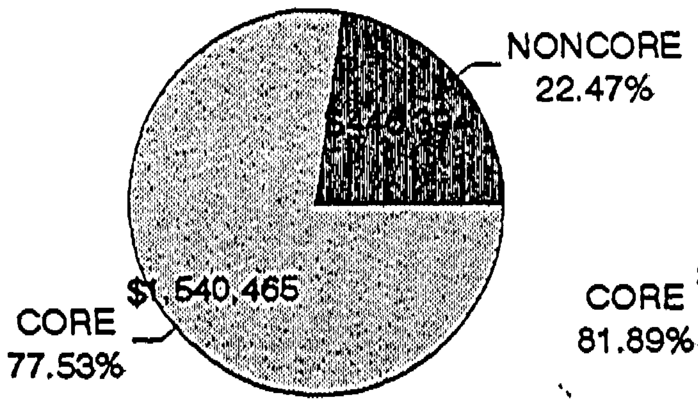

EXISTING REVENUE
RESPONSIBILITY
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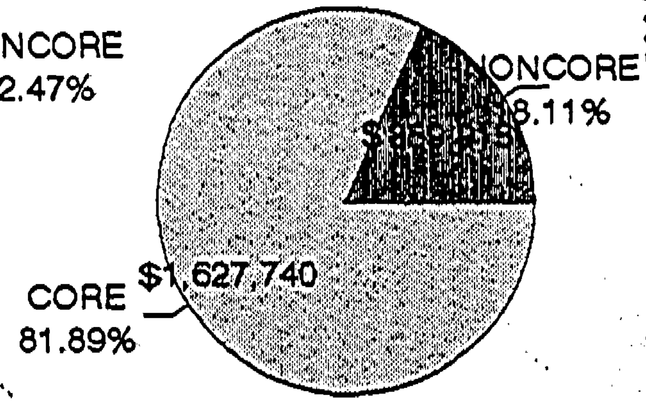
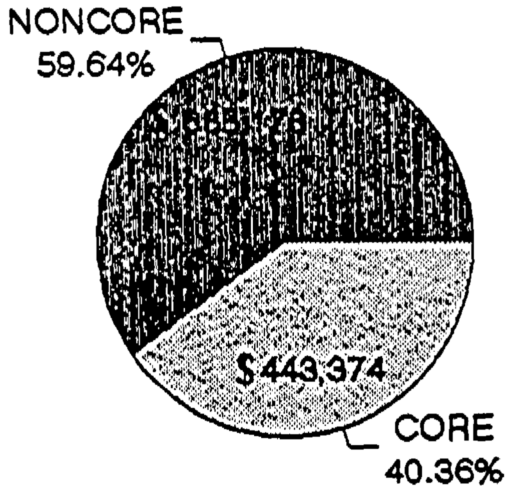


ILLUSTRATIVE
REVENUE RESPONSIBILITY
UNDER MARGINAL COST
($000)

SDG&E REVENUE RELATIONSHIPS



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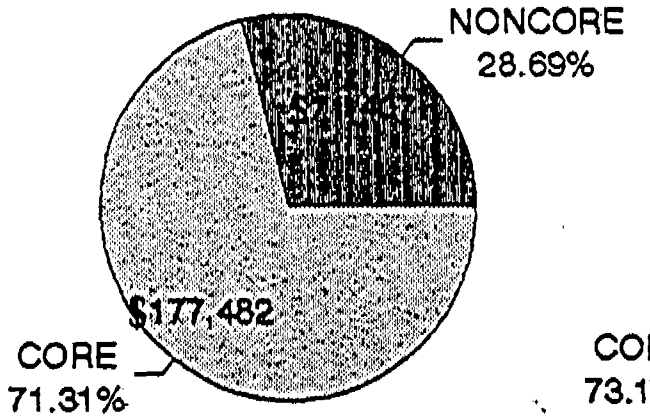
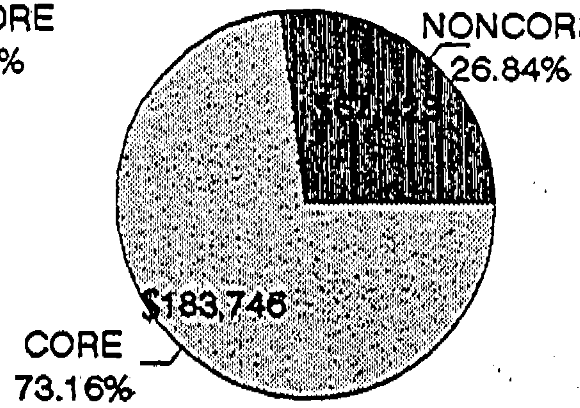


EXISTING REVENUE
RESPONSIBILITY
($000)



ILLUSTRATIVE
REVENUE RESPONSIBILITY
UNDER MARGINAL COST
($000)

1. Background

This proceeding adopts the first long-run marginal cost methodology for California gas utilities. Marginal costs are forward-looking costs: they reflect the costs a utility will incur to meet new demand for its services. LRMC captures the cost of new facilities as well as the short-term marginal costs of daily operating requirements. Our rates today are based on the existing, or embedded, cost of service.

1.1 Industry Restructuring

In 1986 The Commission identified LRMC as a cornerstone of its gas restructuring agenda to address fundamental changes taking place in the natural gas industry. The catalyst for change was at the national level: wellhead price deregulation under the Natural Gas Policy Act followed by Federal Energy Regulatory Commission (FERC) Order 436 requiring interstate pipelines to transport gas to customers in addition to selling their own supplies. In Transportation of Customer-owned Gas (1986) 20 CPUC2d 628, Decision (D.) 86-03-057, referenced in this proceeding's caption, we ordered utilities to provide short-term transportation of customer-purchased gas and proposed to further unbundle gas services using a marginal-cost based rate design. We quickly instituted Investigation (I.) 86-06-005 and a companion Rulemaking (R.) 86-06-006 to provide the forum for unbundling.

We saw a need in the changing gas world for local distribution companies (LDCs) to separate their transportation service from their sales service for customers able to participate in competitive gas sales markets. We also recognized our continuing regulatory obligation to protect the right to reliable service at just and reasonable rates for customers without alternatives or sufficient market power.

An extensive record of hearings, comments, and decisions has implemented unbundled gas utility services over the intervening six and a half years. A conceptual framework for restructuring was set in D.86-12-009, 22 CPUC2d 444, and implemented in D.87-12-039, 26 CPUC2d 213. In D.87-12-039, we stated:

> "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'.... 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." (Id., p. 225.)

Our commitment to marginal cost principles for the gas utilities built on our familiarity with the use of marginal costs in developing revenue allocations and rate designs for the electric utilities.[2] We recognize that although there are major differences between the electric and gas industries, particularly in the production area, there are substantial similarities in the transmission, distribution, and customer service areas.

LRMC methodology developed through submission of detailed utility studies, formal review procedures for interested parties, and Commission-sponsored workshops. We adopted final LRMC guidelines in D.90-07-055 with the intention of implementing the methodology in test year 1992 cost allocation proceedings. D.90-09-089 deferred marginal cost hearings until after capacity brokering issues were considered.

1.2 Hearing Schedule

The scope of this proceeding is sharply defined. The purpose is to adopt a LRMC methodology for the three respondent

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2 In D.92749, 5 CPUC2d 620, which established our marginal cost methodology in 1981 for electric utilities, we found the adopted methodology had a variety of applications. LRMC serves today as the basis of electric rate design and is also used to establish price offerings to nonutility generators and to serve as an evaluation standard for nongeneration alternatives under DSM tariffs and incentive programs.

utilities that can be implemented in the utilities' next Biennial Cost Allocation Proceeding (BCAP) filings. Utilities were required to file a base-case methodology using Commission guidelines and reconciled to the revenue requirement using electric's EPMC method. Several parties sponsored alternative methodologies. Testimony addressed rate design policy objectives generic to the three utilities but service unbundling and final rate design were not within the scope of this proceeding.

Parties served testimony in stages from February 1 - July 2, 1992. Hearings were held in San Francisco from July 7-28, opening briefs were filed August 26 and reply briefs September 8. The sixteen parties participating in the hearing process are listed at Appendix B. This decision will not repeat all parties' positions on each issue.[3] Rather, our focus is a discussion of the principles relied on in deciding each issue. We acknowledge the parties' considerable efforts and cooperative attitude in creating a comprehensive record in an expedited manner.

2. Major Components of Marginal Cost Methodology

Our adopted LRMC methodology is comprised of distinct components which will be discussed in this section. Illustrative average rates using the policies adopted here and in following sections are displayed at Appendix C.

2.1 Resource Planning for Transmission and Storage

While much of the debate in this proceeding has focused on unit marginal cost calculations and revenue allocation, the answers to questions raised in those areas depend significantly on the utilities' planning processes. Resource planning defines and justifies the facilities that a utility will build to meet customer service requirements.

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3 Matrices of parties' positions on each issue are found in Exhibits MC-88 and MC-89.

Transmission and storage are the focus of the planning process because they are "big ticket item" investments requiring a long planning horizon. There can also be more flexibility in the size of facilities the utility chooses to build. As a result, a utility will design its facilities to be large enough to serve the peak demand that the utility expects will occur. Determining the type of demand that requires additional facilities is a key part of defining the utility's resource plan. The other part of the planning process is determining the level of reliability that each utility's system should provide.

2.1.1 Utility Planning Criteria

Utility system planners examine various types of peak demand to insure that their system provides adequate service. PG&E, SoCal, and SDG&E all indicate that a number of different objectives are examined in planning for the capacity of their systems' transmission, storage and distribution facilities. For example, SoCal examined peak-day demand, summer-day demand and cold-year demand in trying to determine which load was the cause of capacity expansion on the system.

While some parties have tried to designate a single type of load as the cause of capacity costs, the different portions of utility systems serve multiple functions. For instance, both PG&E and SoCal agree that storage provides protection for peak-day demand, daily load balancing, and seasonal demand on their systems.

Parties disagreed about the importance of particular functions, but all admit that multiple services are provided. PG&E describes its transmission capacity as providing service on an adverse peak-day, and insuring that noncore curtailments occur no more than once in 5 years. SDG&E contends that its transmission system is designed to meet peak-day gas requirements of core customers, natural gas vehicle (NGV) refueling stations and 20% of noncore load. SoCal uses transmission to provide peak-day gas to core customers, but assumes a certain level of noncompliance during curtailment, and also designs the system to meet a peak summer load. Further, Toward Utility Rate Normalization (TURN) contends that intrastate transmission investments are actually being made to enhance gas-on-gas competition, not to enhance system reliability.

No party has challenged the Commission's assumption in D.90-07-055 that there is a tradeoff between transmission and storage facilities. This again confirms that multiple functions are served by these facilities.

2.1.2 Least-Cost Resource Planning

It is not enough for a utility to use just any combination of resources to meet the needs of customers. An appropriately planned system meets customers' needs at the lowest total cost. When a marginal cost is defined, it is often described as the cost of an additional unit of goods or services. Implicit in the description is that it is the cost of the next unit in an efficient production process. There may be a number of feasible ways of expanding a utility system to meet additional customer load, but marginal cost pricing reflects efficient expansion of the system.

In order to provide a least-cost resource plan, utilities must clearly identify the objectives they are attempting to meet. PG&E has been the clearest in identifying its objectives for noncore transmission service. In the future, each of the utilities will need explicit reliability objectives for both core and noncore customer groups.

The utilities should also consider more innovative ways of meeting resource needs. Questions from the Administrative Law Judge (ALJ), and Division of Ratepayer Advocates' (DRA) testimony clearly indicated that the utilities had not considered the potential impact of DSM programs on their planning processes. The utilities also have not tried to determine the level of reliability various customer groups would be willing to accept at various prices of service.

Since the Commission was interested in expeditiously implementing marginal cost pricing, we accepted some simplifications in setting cost methodologies. We discuss below additional work that will need to be done in load research and forecasting.

DRA demonstrates through cross-examination of PG&E's witness Bonney that in recent years there has been significant changes in PG&E's long-term forecasts of demand growth by class. In particular, DRA notes the long-term forecast of industrial demand has increased by over 100% in just four years and finds a remarkable correlation to PG&E's efforts to increase rate base by $2 billion through construction of the PG&E/Pacific Gas Transmission (PGT) expansion to serve the noncore market in northern and southern California.

Our guidelines called for the use of the 1991 California Gas Report in this proceeding.[4] This is a yearly publication of the gas industry and has never been subject to review by the Commission. Our next review of each utility's resource plan should critically examine the long-term forecast of customer demands.

As of June 1992 SoCal had installed electronic metering for only half of its noncore customers, representing 59.4% of noncore volumes. PG&E had established electronic metering on 88% of its noncore volume, but had no metered daily data available for core commercial or residential customers.

The Independent Energy Producers and the Geothermal Resource Association (IEP/GRA) raise concerns regarding the paucity of underlying load data on utility electric generation (UEG)

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4 PG&E requested and all parties agreed to modifications to its base case load forecast to reflect an updated estimate of bypass and the forecast of Edison's Cool Water throughput. Both are near-term adjustments and were resolved in our recent decision, D.92-10-051.

customers. The utilities have very limited hourly load data, little knowledge of specific demand forecasts prepared by their own electric departments, and make no adjustments to reflect the effects of weather and electric generating unit outages. The UEG load represents some of the largest system customers, who are identified by the respondents as likely bypass targets. We require additional load data and supporting analysis in the next resource plans.

TURN expresses well the additional resource planning issues which need to be addressed by the utilities:

> "First of all, PG&E and SoCal have not presented any evidence that would indicate that their core customers actually value extreme peak day service highly enough that they would be willing to pay what it costs to provide it, if given the choice. Both of these companies assertedly design their systems such that full core service could be maintained even under the most extreme cold weather conditions ever experienced. SDG&E, on the other hand, has undertaken an extensive study, called the recurrence interval study, which compares the costs of the additional facility investments required to maintain service under various weather conditions against the tangible and intangible costs of not serving the load. Based upon this study, SDG&E has concluded that it should plan its system based on a coldest day in 35 years standard, which does not represent the coldest day that has ever occurred in the service area (SDG&E/Roskowski: Tr. 70/8849-51). TURN does not necessarily endorse all of the details of that analysis, but submits that SDG&E should certainly be commended for making the effort, which its larger sister utilities have not.
>
> "Absent such a study, PG&E and SoCal do not really know whether their core customers value peak service sufficiently to be willing to bear the costs of providing it. Further, those core customers have no options for avoiding the cost of peak service if they do not in fact value it that highly. A customer that willingly foregoes gas usage on a peak day saves only the

> tariffed per therm rate, not the much higher cost of providing extreme peak service. Neither PG&E nor SoCal offers any demand-side management programs designed to reduce extreme peak usage in particular, or to reward those customers who do (PG&E/Heffner: Tr. 77/9656; SoCal/Van Lierop: Tr. 69/8785-86). While one can probably assume that many, if not most, core customers would want to maintain full service on an extreme peak day regardless of cost, there may very well be customers, perhaps many of them, who would be willing to endure a certain amount of disruption to their normal activities in order save the additional cost that extreme peak service may entail. If there are enough such customers, there could be a significant impact on the utilities' planning and total cost of service." (TURN O.B. pp. 34-36.)

We will require the utilities to make substantial progress in meeting our objective of a least-cost planning process. We believe that the appropriate forum in which to examine gas industry resource planning under our current regulatory environment is general rate cases. Their plans must include better load data and well-supported service reliability studies. Resource plans for the respondent utilities should:

1. Reflect an appropriately planned system that meets customers' needs at the lowest total cost;

2. Use at least a 15-year planning horizon for backbone transmission and storage and at least a 10-year planning horizon for local transmission.

3. Use short-term and long-term forecasts that are thoroughly documented and that specify all economic, load research, and end-use assumptions.

4. Have adequate underlying load data for each customer class. At a minimum, this means hourly load data for UEG customers, daily load data for all noncore customers, and

statistically sampled daily load data for core commercial and residential customers.

5. Contain UEG load forecasts that reflect the effects of weather and electric generating unit outages.

6. Contain explicit system design reliability objectives for both core and noncore customers.

7. Reflect the findings of service reliability studies documenting the value core customers place on peak service reliability.

2.2 Utility-Specific Investment Plans for Transmission and Storage

2.2.1 The PG&E Resource Plan

PG&E submitted a local transmission plan based on a five-year planning horizon and a backbone transmission and storage plan based on an 18-year planning horizon. DRA's objections to the limited data and short planning horizon for PG&E's local transmission are incorporated in the update criteria in the previous section. All parties accepted the long-term forecast used by PG&E for purposes of this proceeding. Our concerns and schedule for addressing this critical area are also discussed in the previous section. No party expressed further concerns with PG&E's local transmission investment plan. Recognizing the data limitations that need to be addressed, we find PG&E's local transmission plan should be used to calculate marginal costs in this proceeding.

DRA opposes PG&E's backbone transmission and storage investment plan as not being a least-cost resource plan. The specific area of disagreement is PG&E's inclusion of Line 401 expansion rather than the more cost-effective alternative of additional storage capacity with Line 300 expansion. PG&E's plan assumes Line 401, which is currently under construction, will be fully operational in 1993 but then only uses 250 million cubic foot per day (MMcf/d) of its 750 MMcf/d capacity in 1993 and another 150

MMcf/d between 1997 and 2000. Although it is not clear, PG&E appears to add revenue requirements rather than investment costs because it assumes that someone other than PG&E customers will purchase the balance of the project and cover the associated investment. PG&E's witness testified in an earlier Line 300 proceeding, I.88-12-022, that Line 300 expansion was less expensive than Line 401, but stated his rationale here is that Line 401 construction is taking place.

We do not find that PG&E's rationale meets a least-cost planning standard. DRA's combined transmission and storage marginal cost revenues are 44% lower than PG&E's. PG&E raises concerns that DRA's plan may not be able to meet core loads under extreme conditions. We find these concerns adequately addressed by DRA. We recognize PG&E has no present plans to expand Line 300; the option, however, exists and is under Commission consideration in another proceeding. We conclude Line 300 expansion is a least-cost approach to estimating marginal costs of transmission, preferable to using a more expensive expansion project being constructed exclusively for the noncore market. As discussed earlier, we expect significant refinement in PG&E's resource plan in PG&E's next general rate case.

2.2.2 The SoCal Resource Plan

SoCal's planned investments in transmission and storage are set forth in its filing at Table 1, MC-11. SoCal's plan is extremely modest in comparison to PG&E's, with no large additional increments of transmission or storage capacity needed. Interconnections to the Kern/Mojave and PG&E/PGT pipelines, expansion of SDG&E's Line 6900, reinforcement in some high growth areas, and expansion of storage withdrawal capability are all the investments considered necessary to provide for growth over the 15-year planning horizon.

DRA recommends three adjustments: transfer of Line 6900 from transmission costs to a SDG&E direct customer cost; removal of compression facilities from the Kern/Mojave intertie transmission costs, consistent with DRA's recommendation in Application (A.) 90-11-035 that these costs are related to noncore supply diversity rather than demand and should be recovered in incremental pipeline rates; and a decrease from $30 million to $20 million in storage withdrawal expansion based on uncertain noncore demand estimates. We find the record supports DRA's classification of Line 6900 expansion as exclusively for SDG&E and that exclusive-use facilities are best treated as customer costs. For purposes of this decision we will adopt DRA's storage adjustment, as SoCal's witness Philips testified that additional investment would be dependent on noncore requirements that remain uncertain. However, as noted in Section 3.5, these costs may be revised in the event the Commission authorizes the unbundling of storage costs in I.87-03-036. DRA's Kern/Mojave adjustment is considered together with the larger pipeline issues raised by TURN and discussed next.

TURN observes that the utility and DRA estimates of marginal transmission costs for the SoCal system fail to include any costs for the long-distance movement of gas from the state border to the utility's load center:

> "Rather, the SoCal and DRA forecasts were based primarily on the relatively minor facility enhancements required to "debottleneck" transmission constraints in various localized areas of the system, plus (at least for SoCal) the costs of interconnecting with the Kern/Mojave and PG&E/PGT projects in the Wheeler Ridge area. Therefore, TURN has recommended that the marginal cost of long-distance transmission be recognized by adding the tariffed cost of transportation over the Mojave system (which is almost entirely an intrastate pipeline in all but the legal sense) to the costs of the more localized facilities identified by SoCal and DRA.... The only alternative is to assume that there is no marginal cost just because someone other than the LDC is providing the service, a concept to which TURN must strongly object." (TURN O.B. p. 40-2.)

No other party supports TURN's proposal. DRA's policy witness on revenue allocation (Klapow) did individually support TURN's proposal, citing the need to reflect long-line transmission service in rates. Klapow's position is characterized by DRA as a replacement cost approach, one TURN asserts is consistent with DRA's customer-cost and distribution methodology. DRA distinguishes its recommended approach as a forward-looking resource plan that may have very different incremental costs than the replacement costs of facilities in the ground. DRA's transmission plan witness, Roscow, states he did not consider third-party facility investment in his analysis. All parties except TURN strongly object to including third-party investment in SoCal's LRMC as these are not future costs the utility itself faces.

It is clear from the record that SoCal will have sufficient excess capacity on its long-line transmission systems connecting with El Paso and Transwestern at the Colorado River that it will not have to make capital expenditures to expand this capacity over the entire 15-year transmission planning horizon. The importance of this under marginal cost theory is that SoCal should signal in rates to customers that the marginal cost of transmission service is, at this point in time, looking out over a 15-year planning horizon, quite low. As such, we refuse to adopt the proposed decision's recommendation that we use the recently completed Mojave pipeline as a a proxy in calculating the long-line transmission marginal costs for SoCal.

It is ludicrous to burden SoCal ratepayers with "phantom" charges reflective of the cost of new capacity for the use of existing, sunk capacity that is already in excess of demand. TURN's recommendation which is adopted by the proposed decision gives the wrong price signal to customers who would deliver gas to SoCal at existing Colorado River interconnections with El Paso and Transwestern. It would signal that SoCal could provide this service only by constructing new transmission capacity when, in fact, its existing capacity is adequate to meet demand over the 15-year planning horizon.

In addition, TURN's proposal would create a perverse incentive for customers to favor shipping over new interstate pipelines and to further underutilize existing interstate capacity that is already in excess supply. TURN's proposal would only serve to increase the cost of stranded capacity that SoCal's customers will have to bear. As such, for purposes of this decision, we will adopt SoCal's planned investments in transmission and storage as set forth in its filing at Table 1, Ex. MC-11 with the exception of DRA's adjustments to Line 6900 treatment and to the decrease in storage withdrawl investment as discussed above.

We also note that an issue in the PGT/PG&E interconnection proceeding, A.92-04-031, is whether some of the costs of that interconnection are common costs which should be shared by Kern/Mojave. If the interconnection facilities receive incremental rate treatment, both the PGT/PG&E interconnection costs and the Wheeler Ridge compression facilities, A.90-11-035, should be excluded from the resource plan. If Kern/Mojave receives rolled-in rate treatment, the most recent adopted estimates for both sets of costs should be used in the implementation filing.

2.2.3 The SDG&E Resource Plan

SDG&E's investment plan is submitted in Exhibit MC-27, pp. 4-2 and 6-2. The testimony refers SDG&E's 1991-2010 Gas Transmission System Plan, a 20-year outlook of future transmission expansion investment prepared by the Gas Engineering department. The plan's purpose is to identify transmission capacity additions necessary to meet design criteria at the lowest cost level. The plan identifies ten projects for an expansion capability of approximately 250 MMcfd. No storage plan is submitted as SDG&E does not operate any storage facilities separate from SoCal.

No party proposed an adjustment to SDG&E's plan and it appears reasonable.

2.3 Marginal Demand Measures for Computing and Allocating Marginal Cost Revenues

2.3.1 Cost Responsibilities

The purpose of marginal costing methods is to reflect the costs incurred over the long run caused by serving an additional unit of demand. For each function of a utility's gas system, the demand measure used to calculate that function's marginal cost should be the one that reflects cost causation for that function.

The controlling planning criteria used by the utilities reflect the manner in which the utilities will incur costs in response to changes in demand for specific functional elements of their respective systems. Thus, parties' requests that we deviate from the utilities' planning criteria in favor of "flatter" allocation factors could result in adopting measures of cost responsibility which depart from accurate marginal costs.

In issuing Decision 92-11-052, we recognized that uneconomic bypass is an imminent threat presented by several pipeline projects which could attract large noncore customers of PG&E and SoCal. We permitted PG&E and SoCal to submit long-term contracts subject to an expedited review process. Our desire to facilitate long-term transportation contracts is based in part on our policy to prevent unnecessary duplication of facilities and the consequent customer costs.

It is our belief that accurate marginal cost methods will lead to clearer signals when marginal cost-based prices are implemented, thereby providing the opportunity for customers to purchase economically efficient levels of service. The decisions on the chosen measures of cost responsibility described below are based upon accurate cost causation and recognize the interrelated nature of utility operations.

2.3.2 Marginal Demand Measures for Transmission

PG&E refers to the criterion that causes a utility to need more capacity as a marginal demand measure (MDM). This term was readily adopted by all parties. The utilities have chosen to advocate certain MDMs because they represent a combination of the multiple types of peak demand that the utility systems are designed to serve. They also support less extreme demand measures in order to spread costs in a "equitable" manner instead of following cost-causation principles in a strict manner.

For transmission PG&E has chosen to use cold-winter-season demand for its "backbone facilities" and cold-winter-day demand for local transmission. SoCal has chosen cold-year demand as its measure of transmission peak use. DRA advocates cold-year demand for both utilities. TURN contends that average-year demand is appropriate because transmission additions are driven by supply diversity considerations and not capacity needs. California Industrial Group (CIG) and Southern California Utility Power Pool (SCUPP) contend that abnormal peak day (APD) for PG&E and extreme peak day (EPD) for SoCal are the appropriate measures of demand.

APD and EPD are demand measures which signify that only core customers are causing marginal transmission costs and that no capacity is built to serve the needs of the noncore. CIG and SCUPP contend that peak demand occurs on these statistical peak days, and peak demand could potentially be identified with certain peak hours if more accurate data was available. Therefore, only those customers who are forecast to be using the system on that day are responsible for transmission costs.

SCUPP and CIG also contend that equity considerations should be limited to the Commission's choice of caps and floors in actually allocating costs. Marginal cost measures should be calculated in a manner that reflects true cost causation.

We believe that the best estimate of the demand-causing transmission costs on the backbone system of SoCal is cold-year demand, and for PG&E it is cold-year peak season.[5] These measures are chosen because they are the best estimates of cost causation. Transmission is used to provide flowing supplies and to support storage operations. Transmission capacity is relatively constant during the year. SoCal has a larger amount of storage available than does PG&E. Given the amount of storage available, SoCal's backbone transmission system is sized to meet cold-year demand. In contrast, PG&E sizes its backbone system to accomodate cold-year peak season throughput.

2.3.3 Marginal Demand Measures for Local Transmission

PG&E has argued that some of its transmission system should be differentiated from the rest because it serves local areas in PG&E's service territory, as opposed to bringing gas in from outside the territory. SDG&E as a wholesale customer of SoCal argues that the transmission lines it owns should really be considered local transmission as well. The Commission allowed for the possibility of this differentiation in D.90-07-055, when it specified the guidelines for the utilities' marginal cost filings. There is no objection from other parties in the proceeding, and we find it appropriate to designate local transmission systems for these two utilities here.

PG&E argues that the estimated demand on a cold winter day should be used as a demand measure for its local transmission system. As a secondary position, it argues for cold year coincident peak month demand as the MDM for this function. SDG&E argues that the estimated demand on the coldest day in 35 years should be used because that measure corresponds with the results of

5 The compressor fuel costs on the transmission systems are assigned separately. The unit cost estimate is multiplied by average year throughput for allocation purposes.

its reliability study. DRA supports a cold year coincident peak month measure for PG&E, and extends that recommendation to SDG&E.

All of the parties argue that local transmission is the bridge between transmission and distribution. Logically, local transmission would be taking gas from both flowing supplies and storage withdrawal, and transporting that gas to local areas. Essentially, the MDM should be somewhere between transmission and distribution. As will be explained more fully below, a peak day measure should be used for distribution. We will use a coincident peak month measure for local transmission on both the PG&E and the SDG&E systems.

SoCal did not propose a distinction between backbone and local transmission in the functionalization of its transmission facilities. SoCal does, however, put forward a proposal, as an alternate to its recommended position to treat distribution main trenching cost as a customer cost, where a separate allocation is suggested for its distribution system. As more fully explained in Section 3.1 below, we reject SoCal's recommended position on the treatment of distribution main trenching costs. We find merit, though, in SoCal's alternate proposal as discussed in Exhibit No. MC-17, at pp. 19-21 to disaggregate its distribution system into high-pressure and medium-pressure components.

SoCal's high-pressure distribution "supply" lines serve a function similar to PG&E's local transmission lines. For example, both are used to serve those portions of the UEG load not served off the backbone transmission system. It may be that SoCal and PG&E are simply using different criteria for the classification of lines as distribution or transmission. To the extent that identified pipeline infrastructure is similarly characterized between the LDCs, it makes sense to apply a similar cost allocation methodology.

In addition, as part of our policy to address bypass concerns, we are endeavoring to establish a more precise segmentation of the noncore market into customer classes that are more homogeneous in terms of the cost causation on the system. To that end, a more precise segmentation of the intrastate pipeline infrastructure by function is advantageous.

For consistency in our treatment of intrastate pipeline infrastructure between PG&E and SoCal, and because it serves our goal in addressing the bypass problem, we will recognize the distinction between SoCal's high-pressure and medium pressure distribution systems for determining marginal demand measures for cost allocation. Because of the similarities between PG&E's local transmission system and SoCal's high-pressure distribution system, we will also use a cold year coincident peak month marginal demand measure for SoCal's high-pressure distribution system.

In this decision we are unable to develop illustrative rates based on the segmentation of SoCal's distribution system as described above. The medium-pressure distribution system accounts for over 86% of common distribution costs. (SoCal Rebuttal Testimony of witness Van Lierop, p. 42.) As such, the illustrative rates shown in this decision are based on a peak day marginal demand measure for SoCal's entire distribution system. We order SoCal, as part of the implementation phase of this proceeding, to develop demand forecasts and corresponding MDMs that will allow the Commission to adopt long-run marginal costs rates based on separate marginal demand measures for SoCal's high-pressure and medium-pressure distribution facilities as adopted in this decision. SoCal should also provide materials showing the distribution facilities used in each class.

2.3.4 Marginal Demand Measures for Storage

Part of the problem in defining MDMs for the storage function is determining the extent to which it is appropriate to identify subfunctions of storage, and how those subfunctions would be used for cost allocation purposes.

For storage, PG&E had chosen cold year winter season as the MDM for overall storage operations, and then later suggested a number of MDMs to correspond to an additional exhibit ordered by the ALJ that broke storage service down into a number of functions. PG&E argues, however, that one overall storage function is most appropriate at this time. For overall storage DRA agreed that cold year winter season was the appropriate MDM. SoCal's testimony was always divided by function: average year throughput for load balancing; withdrawal capacity on extreme peak day; and injection capacity based on the amount of injection needed to provide 70 billion cubic feet (Bcf) of inventory on November 1 of each year. McFarland Energy, Inc. (McFarland) believes that subfunctions should be identified in the manner that SoCal has suggested, but has different recommendations about how the overall cost of storage should be broken down into subfunctions.

SDG&E does not operate its own storage facilities, but it has a contract for storage capacity on the SoCal system. Since this capacity serves as SDG&E storage, and avoids the need for additional interstate capacity by the utility, we will adopt DRA's recommendation to include the contract cost as an estimate of storage cost and assign these costs in the same way storage is assigned to other utilities.

While the subfunctions of storage are critical to unbundling, this is not the proceeding where that unbundling will occur. Further, as discussed in Section 3.4, we find the record in this proceeding insufficient for subfunctionalization of marginal storage costs. For the purposes of cost allocation, an overall measure of storage cost responsibility is appropriate. The Commission adopts cold year winter season because it reflects the combination of the storage functions provided by the utilities.

2.3.5 Marginal Demand Measures for Distribution

Each of the utilities use a slightly different planning criteria for their distribution systems. PG&E uses abnormal peak day (APD) as the primary planning criteria for approximately 90 percent of its distribution systems. For the remaining distribution systems, cold winter day (CWD) are the primary planning criteria. PG&E's APD has a once-in-65 to once-in-100 year probability of occurring.

The primary planning criteria for SoCal's demand-related distribution costs is extreme peak day (EPD) demand. SoCal's EPD is a once in 60-year probability. SDG&E uses cool-year peak day, with a cool year having a 50% probability of occurring each year. DRA recommends the use of cold year noncoincident peak-months for all of the utilities. DRA recommends a broader measure of cost allocation based on the notion that off-peak users receive benefits from the utility system. DRA views on- and off-peak usage as essentially joint products where the relative costs are impossible to determine. DRA then posits that a competitive market will set relative prices based on the willingness of on-peak and off-peak users to pay to use the system.

One of the central principles of marginal cost pricing is cost causation; that is, the rates charged should reflect the change in the utility's costs that would actually occur if there were an increase in demand. An analysis of cost allocation between on-peak and off-peak use is inconsistent with marginal cost theory. DRA's argument confuses the issue between a marginal cost based allocation and a value of service pricing scheme. DRA's witness on the unit marginal cost of distribution conceded that peak day demand is the best measure of cost causation. DRA testified:

> "In performing the regressions, DRA has used peak day load estimates as have the utilities. This is because they are closer to the actual loads that drive the investments and are more likely to yield better regression results." (Ex. MC-34, p. 6-3)

We agree with SoCal that, absent justification,

> "There is something fundamentally wrong with using one measure of demand to calculate unit

> marginal cost because it best represents the planning criterion, but then abandoning the proper measure in favor of a different measure of demand to allocate costs to customer classes." (SoCal O.B. p. 54)

We do not see a justification for such a treatment in this case. As such, we refuse to adopt DRA's marginal demand measure for distribution which the proposed decision of the administrative law judge has embraced. DRA's proposal should be rejected for two reasons. First, a non-coincident peak month measure does not reflect system planning, and it certainly does not reflect cost causation. Second, DRA's recommended distribution MDM is inconsistent with its load diversification principle. DRA explains the farther upstream one goes on the gas transmission system, the more loads diversify and storage is better able to flatten loads. (Ex. MC-36, p. 2-9) As PG&E points out:

> "The load diversification point applies with equal force to the relationship between the down stream distibution facilities and the upstream local transmission facilities. The load on a local transmission system is the aggregate of the loads from several diverse distribution systems. Therefore, the distribution MDM should be at least as "peaky" as the local transmission MDM." (PG&E O.B. p. 18.)

DRA's recommendation of a flatter cold year noncoincident peak month marginal demand measure for distribution is inconsistent with its recommendation for a cold year coincident peak month allocator for the upstream local transmission facilities.

We adopt the utilities' recommendations of peak day marginal demand measures for their distribution systems. We are not convinced that the claimed inaccuracies in peak-day demand measures is cause not to move forward now and adopt a peak day marginal demand measure methodology for the utilities' distribution systems.

For a local distribution gas utility, core peak demand drives the system peak demand and core demand varies primarily with temperature, reaching its peak in winter with space heating demand. Therefore, forecasting peak day demand implies two steps: first, forecasting the abnormal (or extreme) peak day temperature; and second, using this peak day temperature forecast to forecast the peak day demand. We will address each of these issues, in turn.

By the nature of its definition as an extreme value, the abnormal peak temperature will not recur every year. Instead, the LDC must select a reasonable recurrence interval; for example, SoCal has selected a one in sixty year criterion, which implies that SoCal plans to install facilities which will meet expected core demand on even the coldest day expected to occur in a sixty year interval. Naturally, the selection of the length of this recurrence interval should not be arbitrary but should balance the cost of these facilities with the benefit derived by the core. TURN expresses this resource planning issue which needs to be addressed by the utilities. (TURN O.B. pp. 34-36). A careful examination of this cost-benefit problem indicates that the LDC should evaluate that facility costs over a range of temperatures (i.e., recurrence intervals) and corresponding core demands. We note that SDG&E has chosen to use a methodology which identifies the cost-effective recurrence interval.

The LDC must devise a method to forecast the most extreme temperature which will occur during this recurrence interval. The LDC can forecast the abnormal peak day temperature through one of two approaches, each represented by one of the two major LDCs in this proceeding. In one approach, PG&E refers to a recurrence interval of one day in ninety-five years and directly adopts as the extreme temperature value, the lowest temperature which actually occurred on any day since 1929. In the other approach, SoCal uses a model to forecast the extreme temperature value which will occur in its recurrence interval of one day in sixty years. In its approach, SoCal uses as input to estimate the parameters of its model, the lowest actual (or extreme) temperature values which have occurred in each year in a sample of years spanning the last several decades. SoCal then uses the model to forecast the temperature which will recur with a probability of once in sixty years.

This extreme temperature is then translated into corresponding core demand. In its approach, PG&E has used daily data from 1984 through 1989 to estimate a single relationship between daily demand and system-wide daily temperature. PG&E then uses these estimated parameters of this relationship to forecast the demand when the extreme temperature occurs. In implementing this method, PG&E gathers temperature data from several stations and forms the system-wide temperature with a customer-weighted average.

SoCal has also estimated a daily demand model, but from a database which uses information from a completed survey of several hundred individual customers. The structure of SoCal's daily demand model strongly resembles its end-use demand model and includes not only daily temperature, but also several other variables which characterize the customer's appliances and household size. Moreover, model parameters can vary across SoCal's several temperature zones. To forecast demand on an abnormal peak day, SoCal inputs the extreme temperature value into this model.

In the future, refinement of the cost allocators that we adopt today will require more complete and accurate end-use data. Although significant work has been done in the area of extreme temperature forecasting and its translation into demand, LRMC methodologies will benefit through more accurate data and refinement of forecasting techniques. We believe that the LDCs could benefit from a critical examination of the relative benefits of each other's formulation of both the forecast of extreme temperature and the translation of this information into demand forecasts.

2.3.6 Adopted Marginal Demand Measures

The MDMs we have chosen for computing and allocating marginal cost revenues are those that best reflect cost responsibility. The MDMs are summarized in Table 1.

MARGINAL DEMAND MEASURES

	PG&E	SOCAL	SDG&E
BACKBONE TRANSMISSION	COLD YEAR WINTER SEASON	COLD YEAR	N/A
LOCAL TRANSMISSION	COLD YEAR COINCIDENT PEAK MONTH	N/A	COLD YEAR COINCIDENT PEAK MONTH
STORAGE	COLD YEAR WINTER SEASON	COLD YEAR WINTER SEASON	COLD YEAR WINTER SEASON
DISTRIBUTION	COLD YEAR PEAK DAY	COLD YEAR PEAK DAY	COOL YEAR PEAK DAY

2.4 Capital-Related Marginal Cost

We have four methods of estimating the marginal cost of capital investments for consideration: present worth (PW); total investment; The National Economic Research Associates, Inc. (NERA) regression; and discounted total investment. By briefing, parties reached consensus on the total investment method, except for PG&E and the City of Vernon (Vernon) who prefer PW and SDG&E who advocates the NERA regression method and, as an alternative, the discounted total investment method. In more detail, the four methodologies are:

1. The Total Investment methodology computes an arithmetic average by dividing the total investment during the planning horizon by the total load growth during the same period. The resulting unit marginal cost is then annualized using a Real Economic Carrying Cost (RECC) factor. The RECC capital amortization formula levelizes a stream of future payments in a manner similar to an annuity calculation but with an inflation adjustment. RECC models incorporate assumptions for service life, salvage value, cost of capital, inflation rates, and discount rates.

2. The NERA Regression methodology uses a model developed by NERA to obtain a marginal unit capital cost by regressing the cumulative changes in investment with cumulative changes in load. Parties used a combination of historical and forecast period data. The marginal unit cost is then annualized using the RECC factor discussed above.

3. Present Worth methodology computes the difference between the present value of a planning period's stream of system investments, assuming project spending commences in the current year, and the present value of the same stream of investments, assuming project spending is delayed one year. The difference between the two present value streams is annualized by dividing by the average annual change in the demand measure used for the planning horizon.

4. The Discounted Total Investment method computes a marginal unit cost by dividing the present value of the planning period's investments by the total load growth. A present value is used in the numerator to give additions further into the future less weight than investments in earlier time periods. The marginal unit cost is then annualized using an RECC factor.

The Commission guidelines adopted in D.90-07-055 directed that the PW method be used in calculating marginal cost for transmission and storage investments. These investments generally are large and expensive system additions and the Commission wanted to reflect the future costs in current rates as a signal to guide customers' usage. Commission Advisory and Compliance Division's (CACD) Workshop Report recommended PG&E's PW method because it incorporated, in a manner far simpler than the Energy Reliability Index (ERI) used on the electric side, a means of adjusting LRMCs to "be low in times of capacity surplus, rising to full cost when capacity is constrained." (Workshop Report, p. 17.)

The hearing record provides substantial evidence that the PW method should not be used for calculating marginal capital costs. The method's feature of signaling future costs in current rates is outweighed by its two primary disadvantages: it produces volatile rate spikes and it fails to recover full investment costs. Both Edison and DRA discuss specific examples in their opening briefs. Other parties, such as CIG, focus on PW's inability to signal capacity shortages. We are concerned that the type of rate volatility demonstrated by the PW method would encourage long-term anti-bypass contracts when the rates are low that would prove to be uneconomic in later years.

The Commission's electric methodology uses the NERA regression model annualized with the RECC to calculate marginal capital costs. DRA's Phase I testimony initially recommended this methodology be used for transmission, storage, and distribution. Its recommendation changed when it found regression could produce anomalous results for lumpy investments in transmission and storage. Witness Comnes states: "The regression method does find a slope of a line based on cumulative investment to cumulative demand growth. And there's nothing to stop it from basically getting a large negative intercept. And that can provide for very high marginal costs even in situations where total investment over the forecast period is falling." (Tr. 71:8931-2.) DRA did not find this problem with distribution investments but recommended the simpler total investment method be used consistently for all three functions.

We adopt the total investment method for transmission and storage marginal costs. The NERA regression approach yielded a strong correlation for distribution systems and we will adopt it for this function. By this decision, we do not suggest that it would be inappropriate for the Commission to consider adopting the Present Worth methodology, distinguished as a "trial run" in the proposed decision in PG&E's General Rate Case, A.91-11-036, et al. The record in that proceeding differs from what is before us here. No party advanced the discounted total investment method as its preferred method and PG&E, while accepting total investment and regression as second and third-best alternatives, respectively, strongly opposes this method as not bearing "any conceptual connection whatsoever with a marginal cost" (Reply Brief, p. 31).

While we will use a RECC factor in annualizing unit costs, we note that the models used should be carefully examined for their underlying assumptions. TURN questioned the differences between utilities' models and SoCal's witness Mr. Van Lierop responded satisfactorily in rebuttal testimony (Ex. MC-83, pp. 26-7). We do not find persuasive Vernon's recommendation that inflation be recognized by adjusting the total utility revenue requirement in each utility's annual attrition case rather than in the RECC factor.

We do not place a high priority on developing an ERI mechanism for gas, as recommended by DRA. The process for developing the electric ERI has been extremely complex and lengthy. We have a full gas agenda before us in the next year and believe today's market has substantial capacity.

2.5 Marginal Cost Expenses and Loading Factors

The common expenses associated with utility functions are operating and maintenance (O&M), material and supplies (M&S), administration and general (A&G), general plant (GP), cash working capital (CWC), and franchise fees and uncollectibles (FF&U). The Commission guidelines for LRMC studies issued in D.90-07-055 provides no direction for methodology other than "add administrative and general and operating and maintenance expenses" (37 CPUC2d 66, 69). The lack of specificity appears to stem from the limited discussion of these issues by parties at the LRMC workshops held February 6-9, 1990 (CACD Workshop Report, April 13, 1990, p. 4). The only party asking for further specification prior to the February 1, 1992 utility filings was DRA, who requested the respondent utilities explicity address the marginal cost basis of all included O&M and A&G expenses (ALJ Ruling January 3, 1992, p. 3).

Parties have a great deal to address in this proceeding and have appropriately focused primary attention on costs of greater significance. We commend SoCal and SDG&E for the progress they did make in analyzing marginal components. We note specifically in the following discussion where further analysis should be undertaken and addressed in the first BCAPs subsequent to implementation.

2.5.1 Operating and Maintenance

All parties agree there are two categories of Operating and Maintenance (O&M) costs, demand-related and customer-related. There is less controversy on the customer-related costs and in the areas that do exist, we find electric methodology to be well-defined and applicable.

D.86-08-083 (<u>Pacific Gas and Electric Company</u> (1986) 21 CPUC2d 613, 615) specifically: excludes marketing, service planning, and load management expenses from marginal customer cost expenses; provides for reflection of improvement costs for access equipment of existing customers; and uses a weighted customer average rather than investment level for class allocation. The remaining area of difference is inclusion of uncollectibles. SDG&E includes account uncollectibles in this classification and PG&E includes them in a separate FF&U category. We find both incorrect, based on SoCal's assessment of uncollectibles:

> "uncollectible costs were not included in marginal customer costs. Instead, the uncollectibles costs will be treated as a marginal revenue cost (a cost proportional to revenues collected)." (Ex. MC-16. p. 41.)

Parties have more significant differences in demand-related O&M expenses. PG&E and SoCal relate O&M directly to plant by calculating an O&M/plant ratio using multiple-year data. SDG&E and TURN express marginal O&M as a function of the amount of actual (average year) gas throughput flowing through the system rather than investment. DRA adopts a hybrid approach of calculating a separate unitized O&M cost by an O&M/MDM ratio which is linked to plant investment through the plant planning criteria; its witness proposes annual throughput as an alternative. CIG supports DRA's MDM methodology for A&G and GP as being consistent with the long-established method of treating these costs in the case of electric utilities. We adopt DRA's methodology, using current period costs, on an interim basis. We would like to see further development of SoCal's attempt to segregate O&M into labor, nonlabor, and nonmarginal classifications and we would like each utility to perform regression analyses similar to SDG&E to examine correlation of O&M to throughput. We also find reasonable and adopt the following adjustments:

- Reassignment of PG&E's meter and regulators (Accounts 876 and 890) from the customer function to the distribution function based on FERC account descriptions.

- Adjustment of SDG&E's distribution accounts 887 and 892 to reflect labor cost savings from future plastic pipe installations. This is consistent with the capital cost inclusion of technological improvements made in later sections.

- Reassignment of SoCal's mains related costs from the customer function to the distribution function, consistent with our rejection of the minimum distribution system proposal in Section 3.2.

2.5.2 Material and Supplies

Parties addressing this issue generally express the M&S loader in terms of changes in plant (SoCal and SDG&E) or rate base (PG&E and TURN). DRA has concerns with both approaches as the loader is expressed in terms of embedded plant but applied to marginal plant. DRA proposes the same approach used in O&M, which expresses the loader in terms of units of throughput reflected in the MDMs for each functional category. As the MDMs are a measure of the planning criteria, a relationship to plant is preserved without using plant directly. This approach appears reasonable.

2.5.3 Administrative and General

The principle issue for A&G is whether to use embedded cost based allocators developed by PG&E and SDG&E or apply SoCal's marginal analysis methodology. SoCal analyzes the extent to which each account is marginal or nonmarginal and its A&G study shows that approximately 51% of its A&G costs are nonmarginal. This methodology is also supported by SCUPP and TURN. DRA developed proxy estimates of marginal A&G costs for PG&E and SDG&E from SoCal's study and proposed results that while similar to PG&E and

SDG&E's own estimates, have a marginal rather than embedded basis. We adopt this for interim methodology and direct PG&E and SDG&E to perform their own system studies applying SoCal's analysis.

Vernon requests that wholesale customers be excused from any responsibility for 50 percent of the A&G component of the revenue requirement. We find there is insufficient evidence on the record to support this request.

2.5.4 General Plant

General Plant is proposed as a ratio to: plant by PG&E; rate base by SDG&E; and O&M labor by SoCal, DRA, TURN, SCUPP, and CIG. The major components of general plant are buildings, furniture, computers, and communications equipment. We agree with SoCal and DRA that these components are generally purchased to support labor intensive activities and, consequently, the costs vary more with the number of employees than with the miles of pipe. SoCal and DRA each propose a distinct calculation. We accept DRA's proposal, as it is consistent with the methodology adopted for the other loaders.

2.5.5 Cash Working Capital

The only two parties to propose a CWC loader are PG&E and SDG&E. We find that working capital is caused by factors broader than plant or rate base and, therefore, should be reflected in terms of the total size of utility revenues and expenses and captured by EPMC in the revenue allocation phase.

3. Marginal Cost of Utility Functions and Class Revenue Allocation

3.1 Marginal Customer Costs and Revenues

Marginal customer-related costs measure the cost of a customer's access to the gas utility's supply system.

All three utilities filed a base-case using the service, regulator, and meter (SRM) investment cost method pursuant to the guidelines established in D.90-07-055.[6] The issues of difference among parties are:

- TURN and PG&E advocate a new customer only (NCO) method of assessing capital costs to each class rather than the market rental approach used by other parties.

- SoCal increases customer-related capital costs by adding a minimum distribution system calculation to the base-case SRM methodology.

- DRA advocates including increased trenching costs for the service line replacements. No opposition remains to using class specific service line length.

The NCO and minimum distribution system proposals are issues that the Commission has previously considered for electric marginal cost pricing. In <u>San Diego Gas & Electric Company</u> (1988) 30 CPUC2d 299, we chose to replace an incremental/decremental method similar to NCO in favor of recognizing the opportunity costs of existing facilities as the long-run marginal cost of expanding service.

> "Finally, we believe the most appropriate methodology for determining the cost of access equipment is DRA's rental market approach. We recognize that our rejection of the incremental/decremental methodology contradicts the discussion contained in D.86-08-083, PG&E's 1986 ECAC proceeding. However, the proceedings over the last two years have given us an opportunity to understand the marginal cost principles involved with marginal customer costs better than we did two years ago. Accordingly, it is now clear that the incremental/decremental methodology is not

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6 The service drop-regulator-meter (SRM) measurement of gas premise equipment was adopted as comparable to electric service's transformer-service drop-meter (TSM) in D.90-07-055. See also discussion in CACD Workshop Report, April 1990, p. 13.

consistent with our marginal cost principles as discussed above."

The NCO proposals of TURN and PG&E provide no persuasive reasons for the Commission to deviate from established methodology. TURN labels its proposal a "second-choice" alternative to hookup charges and PG&E advances a proposal consistent with a request in its pending electric general rate case but with little theoretical support provided here. We choose instead to adopt the well-developed rental market approach used for the last four years in electric. We may revisit this issue if the "trial run" of new methodology adopted by the Commission in PG&E's latest general rate case, A.91-11-036, et al. proves successful.

In the same SDG&E electric decision we also clearly articulated our reasons for rejecting the minimum distribution system proposal:

> "The classification of common distribution costs as either demand or customer-related was a major area of controversy. SDG&E estimated the customer-related portion of common distribution costs using a proxy for the 'minimum distribution system' method. This method assumes that 50% of non-energized facilities and 25% of the energized facilities required to provide customers with access through the distribution system are customer-related."

* * *

> "We prefer the approach of identifying specific equipment as access related and assigning the investment costs directly to the appropriate customer class. While there is not a clear line of distinction between demand and customer related equipment, we believe the TSM method provides us with the best approximation. Accordingly, we will treat the remaining common distribution costs as demand-related."

SoCal's proposal for a minimum distribution system component does not specifically identify the distribution cost component attributable to customers, but instead relies on the recorded accounting costs of trenching as a proxy. The company also provides evidence through a regression analysis study of a high correlation between distribution investment and number of customers. While supportive, this evidence is not conclusive. The zero-intercept method of calculation, advocated by CIG and Vernon, is considered but not proposed by SoCal. Zero-intercept methodology has also been unsuccessfully advanced on the electric-side. TURN advocates a MDS calculation (using trenching proxy or zero-intercept) be excluded from both marginal customer and demand methodology as it is a component driven by density and location, not the number of customers or demand.

In the middle of the SoCal and TURN positions is the SRM methodology adopted in D.90-07-055 and recommended by PG&E, SDG&E, and DRA. SoCal and CIG argue that SRM is not directly analogous to the TSM electric methodology because transformers serve multiple customers. We find, however, SRM is substantially comparable to TSM and draws the "brightest line" between customer and demand related costs. Therefore, we adopt the proposed methodology.

Consistent with the use of SRM for small customers is the cost assignment of dedicated, exclusive-use, facilities to large customers. SDG&E raised the issue that inconsistencies existed between utilities in assignment of dedicated costs. DRA investigated and made some adjustments but did not have the time and data available to complete. Each respondent utility should ensure that all large customers' dedicated cost assignments are included in its implementation filing.

A related issue is the treatment of large exclusive-use facilities planned to be built to serve a customer. DRA identified Transmission Line 6900 expansion in SoCal's Resource Plan and correctly classified the costs instead as a marginal customer cost for wholesale customer SDG&E as well as an part of SDG&E's own investment plan.

DRA's position that future replacement of existing service lines with gas-only trenching and pavement cutting and resurfacing creates a significantly higher cost than new installation and therefore must be reflected in the marginal cost is also consistent with electric LRMC methodology. D.86-08-083 defines customer-related costs to include replacement and improvement costs for existing customers' access equipment as part of customer-related costs. In this proceeding we use available SoCal and PG&E data showing replacement cost is about twice that of new installation and direct the utilities to keep separate records of replacement costs and new business for the service lines, as well as tracking the trenching share to the gas company for new installations, to better measure the cost resulting from adoption of the replacement cost assumption.

We can also use the Commission's experience in electric marginal costing in deciding another issue before us. As discussed above, D.86-08-083 provides for improvement costs for access equipment of existing customers and an explicit adjustment for plastic pipe is clearly within this definition.

3.2 Marginal Distribution Costs and Revenues

The issues of greatest contention, marginal demand measures, annualization methodology, and a minimum distribution system, are addressed in Sections 2.1, 2.4, and 3.1. The remaining issues are:

- TURN's removal of trenching costs from marginal demand costs and treatment of a substantial portion of the remaining marginal distribution costs as a one-time hookup charge attributable to new customers only.

- Reflecting the UEG load served by SoCal in marginal distribution cost allocation.

- DRA's adjustment for future replacement costs.

- The time period to use for facility investments.

TURN proposes that the costs of trenching (or of the MDS as measured by zero-intercept) should be treated as non-marginal with respect to both demand and number of customers, and the remaining distribution investments should be viewed as 80% due to new load and treated as a one-time hookup charge attributable only to new customers and 20% as a traditional demand-related cost attributable to all customers. TURN's NCO approach is very similar to its argument advanced for customer costs but less "pure" in isolating new customer cost responsibility.

We acknowledge the difficulty of all methodologies in identifying with precision what are marginal demand-related distribution costs. In this area we chose to adopt an approach that is consistent with our customer-cost methodology, which only classifies as customer-related those costs clearly associated with providing access to the gas system. PG&E expresses well our rationale:

> Splitting the distribution system into customer related and demand related components adds additional complexity to the marginal cost calculations without giving any particular assurance of better accuracy. Just as one could argue that some component of the distribution facilities is customer related, one could also argue that some component of the SRM facilities is demand related. (Ex. MC-73, pp. 1-8 - 1-9.)
>
> The better approach in this case is the simpler, bright-line SRM approach, which treats all SRM facilities as customer related, and all distribution facilities as demand related. (Ex. MC-78, p. 1-9). PG&E O.B. p. 37.

SoCal's filing showed no UEG load at distribution level. After a request for information for the record, SoCal introduced at hearing on July 21, 1992 Exhibit 45. This document identifies each UEG customer and each UEG customer's plant served by SoCal, as well as the volumes at each location served at transmission and at distribution based on 1991 recorded deliveries. Exhibit 45 shows 10 of SoCal's 23 UEG customer plants, 8.3% of annual UEG deliveries, are served at distribution level. SoCal's ignorance in this matter causes some concern regarding the fundamental data underlying LRMC. Given our desire to address the segmentation of SoCal's distribution into high- and medium-pressure components, SoCal is directed to include applicable UEG load in the respective components for cost allocation in its implementation filing.

DRA's future replacement cost adjustment is consistent with the methodology and rationale for measurement of marginal customer-costs and should also be applied in calculating marginal distribution costs. In addition, SDG&E retirements should be adjusted for the relative cost difference between new and replacement work prior to netting them out of the rate base additions used in the NERA regression.

Parties differed in the time period to use for facility investments. DRA, SDG&E, and Vernon prefer a 10-year historical and 5-year forecasted mix, while PG&E and SoCal prefer historical only. We find the argument for a longer period consisting of 10 years historical and 5 years forecast to be persuasive.

3.3 Marginal Transmission Costs and Revenues

All issues for marginal intrastate transmission have been addressed in the resource plan and earlier sections. We do have, however, an issue concerning marginal interstate transmission costs.

In a January 3, 1992 ruling, the ALJ directed the respondents to include interstate pipeline costs in their base-case studies, consistent with the workshop report and guidelines.

Both PG&E and SoCal use the weighted average rate of interstate pipelines on the margin as a basis for their interstate transmission marginal cost and SDG&E uses the guideline methodology of a specific expansion pipeline as a proxy. TURN's testimony supports SDG&E's method and objects to SoCal's approach of including existing pipelines, which significantly understates cost.

No party in the proceeding, including the respondent utilities, argue that estimates of interstate transmission marginal costs are necessary for retail ratemaking. Most agree with SDG&E's position that the current capacity brokering proceeding obviates the necessity of providing these types of estimates[7]. TURN advocates adopting interstate marginal transmission costs for use in cost-effectiveness analysis and other purposes; however, as DRA cautions:

> In certain Commission proceedings, estimates of interstate transmission marginal costs will be useful. For example, UEG marginal gas costs, including interstate transmission marginal costs, may be used for qualifying facility (QF) avoided cost pricing. However, given the variety of pipeline options now available to California, the interstate transmission marginal cost may vary from customer to customer. Thus, adopting an LDC interstate transmission marginal cost may not serve any useful purpose.

Based on the record here, we will refrain from adopting a LRMC methodology for interstate-transmission marginal costs.

3.4 Marginal Storage Costs and Revenues

Storage unbundling proposals are being separately and contemporaneously considered in the storage investigation, I.87-03-036, with the program proposals of SoCal and PG&E. Our objective in this proceeding is to define a long-run marginal cost

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7 Interstate transmission costs will be charged to core customers at FERC-approved rates and will be an optional service to noncore customers per our capacity brokering decisions, D.91-11-025 and D.92-07-025.

of storage methodology that reflects today's systems and can also be adapted to possibly unbundled storage services. Unlike the other functions of customer cost, distribution, and transmission, we have attempted to subfunctionalize the costs and the cost allocation. SoCal filed its testimony with marginal unit costs and allocation for the subfunctions of injection, withdrawal, inventory, and load balancing. PG&E filed its testimony on an aggregated storage basis but, when requested by the ALJ, filed supplemental testimony for the subfunctions of load balancing, seasonal cycling and APD Protection.

The hearing record is contentious, particularly on the issue of load balancing. Even in identifying the subfunctions, while most parties agree on classification by injection, withdrawal, and inventory, PG&E asserts there is no data on the record in this proceeding to allow its facilities to be so classified. SoCal also based its noncore demand estimates not on reliability criteria but instead on a proposed storage program it has since withdrawn. By closing briefs, only McFarland and CGMG remain supportive of the Commission subfunctionalizing LRMC for storage in this proceeding. SoCal states:

> Among the issues that should be decided in the storage investigation are: (1) what storage costs are attributable to load balancing service and how should those costs be allocated among customer classes? (2) what is the amount of inventory capacity that should be reserved and allocated to seasonal cycling for the core and wholesale classes, and what is the demand for unbundled inventory capacity available to the noncore class? (3) how much injection capacity should be allocated to the core in light of the inventory capacity that will be allocated to it? (Reply Brief, pp. 28-29.)

We find the evidentiary record here only supports adopting aggregate marginal storage costs. The issues of load balancing, subfunctionalization, and optimal investment levels have been further developed in three weeks of hearings in I.87-03-036 and SoCal's related application. If a decision in the storage proceeding authorizes SoCal to unbundle its storage services, then SoCal should present a subfunctionalized showing in the implementation proceeding. The showing should combine the factual findings in the storage proceeding with the methodology adopted here.

3.5 Marginal Energy Costs and Residual Air Emission Values

The Commission's guidelines did not direct energy marginal cost be included in the base-cases because the commodity is unbundled from noncore rates. No utility included this function in its filing and the only party to advocate its consideration, TURN, recommends that should the Commission develop a full LRMC of gas for resource evaluation and planning purposes, use of the Energy Commission's most recently adopted long-term gas price forecast would best suit the purpose.

Several parties did address the need for a residual emissions value similar to the electric methodology. TURN testified that consistency with electric ratemaking requires air emissions values be included as a commodity-related cost tied to actual therm usage, regardless of from whom the gas was purchased. The value of residual emissions from natural gas combustion would vary seasonally as well as across customer classes due to differences in typical combustion temperatures for various end uses. TURN recommends the Commission adopt the principle here and direct the utilities to include estimates of such costs in their BCAP implementation filings.

No other party recommends the issue be resolved this quickly. DRA supports further investigation, but would delay consideration until after the first BCAPs following issuance of this decision. PG&E and SDG&E assert no party provided substantive testimony on the issue and, therefore, it would be premature to do anything more than identify the topic as a possible area for future examination. SoCal objects to the reflection of gas emissions cost in its gas rates because it does not believe emissions costs are reflected in the cost of other competing energy sources and because implementation would result in shifts in cost allocation. Opposition to consideration of residual emissions values also comes from SCUPP and CIG. Their jointly sponsored rebuttal testimony recommends TURN's proposal be rejected because it encourages bypass. They assert this occurs because the volumetric allocation of emission costs would shift additional revenue responsibility to high load factor noncore customers, who have potentially more alternatives to utility transportation service than do others.

We find, consistent with electric energy policy, residual emissions values should be addressed in ratemaking. The development of values on the electric-side has been a complex and lengthy process. This issue does not have near-term priority. We will consider addressing this issue in our first re-evaluation of LRMC methodology after the 1993 and 1994 BCAPs.

4. Reconciliation of Marginal Cost Revenues to Revenue Requirement

Marginal cost revenues need to be scaled to the embedded-based authorized revenue requirement under our ratemaking procedures. It would only be by coincidence that marginal cost revenues would equal a utility's embedded cost revenue requirement. Without some type of reconciliation, the utilities will either receive a windfall if marginal cost revenues are greater than the revenue requirement or a shortfall if the marginal cost revenues are less than the revenue requirement. The reconciliation step provides the companies with a reasonable opportunity to earn their authorized revenue requirement.

Our objective is to do this in a fair manner that preserves the efficient pricing signals of marginal cost. Parties used the Equal Percent of Marginal Cost (EPMC) developed in electric ratemaking with recommended adjustments for natural gas application[8]. Two types of adjustments are proposed:

1. EPMC by function. PG&E recommends marginal cost revenues for each function be reconciled to the embedded revenues associated with that function. SDG&E and other wholesale customers recommend a functionalization that separates transmission and storage from distribution-related costs.

2. Separate treatment of nonbase revenues such as pipeline demand charges, balancing accounts and transition costs that have previously been established with specific core/noncore allocation and risk sharing methodology.

Electric ratemaking is done by "EPMC on total"[9]. PG&E proposed a functional approach for gas to eliminate cross-subsidies between functions, thereby better positioning itself to compete in potentially unbundled services such as storage and intrastate transmission. Wholesale customers and Vernon support functionalization to isolate themselves from any common distribution costs. PG&E's testimony states:

> "EPMC revenue reconciliation by function ensures that the embedded costs for each component of the system are allocated only to those customers using that component. For example, under EPMC by function, a customer class using transmission-only service would be allocated only the class share of the embedded

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8 CGMG did not advocate revenue reconciliation with EPMC for any unbundled services. Pricing services at long-run marginal costs will force the utility to operate more efficiently and to make economically efficient investment decisions regarding plant expansions. In the short run, if there are stranded costs that have to be recovered somehow in the utility's rates, its witness recommended the costs be allocated among all customers through "some sort of a 'base rate' concept" (CGMG O.B. p.19).

9 Under this approach, each class' marginal revenue responsibility is scaled up (or down) by the percentage difference between <u>total</u> system marginal cost revenues and <u>total</u> system embedded cost revenue responsibility.

> transmission revenue requirement. Thus, there is no cross subsidy among customers using different components of the transportation system."
>
> * * *
>
> "Additionally, the functional reconciliation will provide the foundation for the unbundling of services that PG&E expects to see as an outcome of the storage unbundling proceeding (I.87-03-036); the capacity brokering proceeding (I.88-08-018) and the FERC's Mega-NOPR. Costs for any unbundled services can simply be treated separately in the cost allocation process if and when the service becomes unbundled, without affecting the allocation of the rest of the revenue requirement. Furthermore, reconciling by function will allow PG&E to compete with other providers of unbundled transportation service who price their service at embedded cost and do not subsidize other functions in their pricing."

SoCal, DRA, Edison, TURN, CIG, and SCUPP support reconciliation to "EPMC on total". DRA's testimony shows mathematically that PG&E's approach loses all demand-driven marginal cost information. Further, it states "The essential benefit of marginal cost based rates is in fact the redistribution of ratemaking costs amongst the various aspects of utility service to reflect current and future market conditions for each service function" (Ex. MC-36, p. 1-5). Generally, the marginal costs for transmission and storage are higher than the book-valued capital assets while marginal distribution and customer-costs are quite close to embedded costs. Opponents of EPMC by function agree with Edison's assessment:

> "(1) it does not use the marginal cost information developed in Phase I; (2) EPMC by total results in more efficient outcomes than EPMC by function; (3) marginal costs, not embedded costs, are the relevant measure of subsidies so PG&E's proposal to scale back revenues to embedded levels actually increases

rather than decreases the potential for cross subsidization; and (4) EPMC by total is consistent with unbundling so long as the utility has the ability to flexibly price between its EPMC-scaled price and marginal costs." (Edison O.B., p. 33.)

The arguments of SDG&E, Palo Alto, Vernon, and Long Beach that EPMC by total unfairly allocates them retail distribution costs hinges on whether embedded or marginal costing provides the accurate measure of cost incurrence. As SCUPP argues:

> "PG&E advocates functional scaling, but its witness acknowledged the mathematical correctness of DRA's analysis. And the witness for San Diego Gas & Electric Company ('SDG&E'), while complaining of 'cross-subsidies' in the proposals of SoCalGas and DRA, recognizes that the 'subsidy' results from the marginal cost calculations themselves, not the reconciliation method. In short, the critics of reconciliation by total (or 'true') EPMC appear to quarrel with the results, not the method itself. Their recommendations should therefore be rejected." (SCUPP O.B., pp. 29-30.)

We find EPMC by total to be appropriate for natural gas as well as electric ratemaking. We cannot support at this time wholesalers' argument that embedded rather than marginal costs better reflect the cost of facilities they utilize as this is contrary to the fundamental premise of this proceeding. The concern expressed with being included in a revenue reconciliation scaler is also problematic. In this proceeding, marginal costs are scaled up, but in future proceedings wholesale customers could benefit from the scaling down of LRMC to a revenue requirement. We reject the use of embedded costs--functional EPMC--to set their revenue allocation or justify a different revenue reconciliation treatment. We remain concerned that the unique nature of wholesale customers may warrant treatment that correctly excludes them from cost allocations.

The next issue is defining the base revenues for EPMC. PG&E proposes the entire revenue requirement be reconciled by EPMC. SDG&E proposes treating existing balancing account balances by established allocation methodology and costs incurred after LRMC implementation by EPMC. SoCal, DRA, TURN, and other parties support retaining the existing balancing account treatment due to the Commission's previous determination of customer obligations and considerations of equity.

Gas ratemaking differs from electric in that we have divided gas customers into a core/noncore grouping and assigned each different cost responsibilities. When the Commission instituted gas restructuring it designated certain costs as "transition costs" and elected to allocate these costs on an equal cents/therm basis. We also determined the fixed costs assigned to the core are fully protected by a balancing account while the utility is at risk for 25% of the fixed costs allocated to the noncore. Lastly, we recently decided in our capacity brokering D.92-07-025 that interstate pipeline demand charges should be unbundled and assigned directly to different customers.

We will retain existing balancing account treatment for the implementation phase and revisit the issue in the next BCAP cycle. We will also continue to treat Lost and Unaccounted For Gas (LUAF) on an equal cents per therm basis until SoCal and SDG&E submit the results of their studies and PG&E updates its supporting data. We find reasonable DRA's recommendation that EOR contract revenues, to the extent they exceed EOR marginal cost revenues, should be used to reduce the EPMC scaler.

The EPMC scaler for each respondent utility is: 6% for PG&E; 16% for SoCal; and -8% for SDG&E.

5. Proposals for Modification of Customer Classes

5.1 Segmentation of the Industrial Class

Only one of the respondent utilities, PG&E, proposed dividing the industrial class. PG&E's proposal is for two subclasses, those customers with peak month usage greater than 500,000 therms and those with peak month usage less than 500,000 therms. PG&E's primary purpose for this recommendation is to prevent uneconomic bypass and they are supported for this reason by TURN.

Several parties, CIG, SCUPP, IP, CGMG, and initially DRA, strongly oppose segmentation by size rather than by a transmission/distribution split as cost differentiation is more related to the facilities used to serve the customer than the size of the customer. SoCal makes a related recommendation with respect to the distribution system, using high and medium pressure service. SoCal's alternative proposal, which was not carried through from cost development to rate design, was addressed in section 2.3.4. IP presents a general proposal to split PG&E into four industrial schedules and SoCal into six.

We find the evidence supports service level distinction having a stronger cost foundation than size. PG&E testifies it segmented the classes based upon cost differences, but the cost difference is primarily service level based. PG&E witness Burns testified that intraclass cost differences:

> "...occur primarily due to the cost of the facilities that are required to serve each industrial customer subgroup. The biggest determinant of cost distinctions by size is that PG&E requires relatively fewer facilities to serve larger customers because larger customers often take service at the transmission level." (CIG O.B., p. 84.)

The main concern in using service level distinction is that expressed previously by the Commission in <u>Rate Design for Unbundled Gas Utility Services (1987)</u> 26 CPUC 2d 213, 260-1:

> 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.

We believe our development of LRMC methodology and the emerging bypass options available to customers provide a different setting than when we considered industrial class segmentation in 1987. Our record here is incomplete; SoCal, SDG&E, DRA, and CIG request we defer a decision on segmentation until more detailed information can be examined in the implementation phase. We direct the respondent utilities to work with interested parties to provide the information necessary for us to consider segmentation proposals that include service level distinctions in the implementation proceedings.

5.2 Combining the UEG and Cogeneration Classes

SoCal's initial filing proposes combining the UEG and Cogeneration classes into a single class in order to be able to offer firm service discounts to individual UEG plants capable of uneconomic bypass without having to reflect the discounts in cogeneration customers rates. SoCal believes its proposal meets the rate parity requirement of PU Code § 454.4.

California Cogeneration Council (CCC) supports the single electric generation class but insists any individual UEG discounts be included in rate parity calculations and provides its own contract methodology to replace current ratemaking practice.

PG&E, Edison, and SCUPP do not support combining the rate classes as the cost differences between them would be masked. DRA recommends combining the classes but retaining a cost of service subtotal for each separately, so that the extent of the cogeneration subsidy can be easily ascertained. No party supports CCC's rate parity position. DRA considers the CCC proposal inequitable for three reasons:

1. Including the effect of discounts in UEG/cogen parity calculation requires the LDC to offer a larger discount than would otherwise be the case.

2. The proposal results in cogenerators paying a rate that is actually less than that paid by UEG facilities that are not receiving a discount (see Ex. MC-65, Table 4).

3. Potential discounts to cogenerators are not considered in the rate parity calculation, only discounts to UEGs. This potential windfall for individual cogenerators is quite possible as SoCal has a pending advice letter seeking authority to offer substantial discounts to three cogeneration customers. (DRA O.B. pp. 73-5.)

We have requests for firm service discounting before us in other forums. We are not deciding the issue here and therefore the requests to set rate parity methodology incorporating or excluding discounts is premature. We should retain separate customer classes for UEG and cogeneration for the purpose of reflecting cost differences.

5.3 Core Deaveraging

Core deaveraging of rates is proposed by SoCal in its filing. Commission policy has been to average the rates of core residential and commercial schedules. SoCal testifies this policy creates subsidies within the core class which unduly benefit residential ratepayers and should be re-examined by the Commission. Many parties share SoCal's concern but do not support the issue being resolved at this time; they indicate the objective and first priority of this proceeding is to move from embedded-base rates to LRMC. The illustrative rate impact of SoCal's proposal is far greater than the rate impact of shifting to LRMC. DRA notes the transportation component of residential rates could increase by as much as 22% and the transportation component of nonresidential core rates could decrease by as much as 60%.

SoCal later indicated it does not attach a near term priority to this recommendation. The only party advocating immediate adoption is CGMG, a party also requesting immediate implementation of unbundled LRMC rates.

TURN recommends that if the Commission addresses this issue in the future, it should do so with cost information based on more than an end-use classification. It cites both PG&E and SoCal as agreeing that end use, in and of itself, is not a cost-based distinction.

We agree core customers' cost and class definitions would need to be re-examined in connection with core rate deaveraging. We believe the issue is appropriately considered in a cost allocation proceeding, and we will consider it in the 1993 and 1994 BCAPs.

5.4 Individual Wholesale Customer Classes

The City of Palo Alto requests the Commission treat each of the four wholesale customers on PG&E's system as a separate class for the purpose of allocating LRMC. Its recommended methodology was submitted as written testimony, which no party at the hearing chose to cross-examine; and the testimony was received in evidence as Exhibit MC-90.

PG&E states it does not oppose Palo Alto's proposal but offers no further support. DRA opposes the proposal, stating this level of disaggregation is unnecessary at the present time and further complicates the allocation process. Additionally, if this request is granted, it is likely to lead to requests by some of the larger industrial customers for individual cost allocations.

We do not find Palo Alto provides a compelling reason to add further complexity to the allocation process and its request is denied at this time. However, in the implementation phase wholesale customers will be allowed to show how they are unfairly harmed by use of EPMC by total.

6. Additional Rate Design Proposals

6.1 Rate Caps and Floors

For several years we have planned to use LRMC information in rate setting. Competitive market forces quicken our timetable to incorporate this information in decision-making.

Parties addressed the issue of rate caps and floors in this proceeding. Most recognized the potential need to mitigate rate shock in the transition to LRMC methodology.

DRA recommends capping rate increases at 5% above the system average rate change, the usual electric cap. TURN supports a 3% cap. SoCal and Edison support a cap of "at least 5%," CIG and SCUPP find a cap unnecessary but recommend, if one is adopted, it be at least 10%. SDG&E strongly supports capping core rates but excluding wholesale customers from a recovery mechanism; PG&E would wait until implementation to determine what is needed.

IEP/GRA asserts there is substantial reason to doubt the integrity of the data underlying the utilities proposals, especially for the UEG class, and therefore recommends against implementation of LRMC at this point. Should the Commission determine to move forward, IEP recommends rate change be limited to system average percentage change, plus or minus 5%.

No other party recommends a floor, however, TURN's states its cautious recommendation of a 3% cap addresses uncertainties: "the potential benefits of rapid movement are outweighed by the real potential for changes of direction in the not-too-distant future" (TURN O.B. p. 61).

We recognize that significant rate changes may result from implementation of marginal cost based rates. The realities of the competitive market for natural gas in California and the substantial opportunities for bypass require an expeditious implementation of LRMC-based rates. Based on the illustrative rates which appear in Appendix C, in contrast to the ALJ's proposed decision, we are not inclined to consider any rate caps or rate floors.

6.2 Customer-Specific Discounting of Rates

SoCal initially advanced a proposal for discounting of rates on a customer-specific basis. Parties positions varied, although those supporting the concept generally set a floor at the customer's class LRMC. At final briefs, SoCal, PG&E, SDG&E, and DRA request the issue not be decided on this record. We have proposals before us in other filings and will not decide it here.

6.3 Stand-by Rates

DRA proposes that:

> "Bypass customers who wish to maintain either partial service or standby service from gas utilities should be charged a peaking service rate as proposed by SoCal Gas in the storage unbundling proceeding." (Ex. MC-36, p. 1-3.)

No party presented a specific proposal here. Although this was initially an issue in the storage proceeding, ALJ Weil deferred consideration of the issue to the SoCal BCAP to be filed in the spring of 1993. Since stand-by rates are a tool which the

Commission should consider, parties wishing to propose stand-by or peaking rates may do so in the BCAPs.

6.4 Unbundled Service Options

CGMG requests that the Commission establish unbundled LRMC for potential service options, specifically functionalized storage, gas gathering, billing, and brokerage costs for core customers. SoCal and McFarland support establishing functionalized storage costs; the record limitations which preclude such action are discussed in Section 3.4.

CGMG presents only general testimony on the feasibility and desirability of unbundled service options for gas gathering, billing, and core brokerage costs. PG&E witness Sneider testifies to a legislative prohibition that does not allow gathering costs to be separately charged in rates, thereby making cost collection an unproductive exercise. We find insufficient evidence to consider these issues and, with a crowded gas agenda before us, assign them a low priority.

6.5 SoCal Request for Interim Rates

SoCal requests that the Commission authorize an interim reallocation of costs from this record. It requests the 60%/40% reallocation of A&G expenses proposed by ALJ Barnett but not adopted by the Commission in SoCal's last BCAP be placed into rates on January 1, 1993. SoCal states the request is not based on any relationship to our LRMC record; it's purpose is to quickly move rates in the direction indicated by the illustrative LRMC numbers. SoCal further asserts that despite specific rulings stating this proceeding would not implement rates, there is no statute or rule that requires notice to the public when a rate change is imposed at the initiative of the Commission.

We find SoCal's request that we would consider authorizing a rate increase without notice and evidentiary support without merit. Its request is denied.

7. Implementation Schedule

The objective of this proceeding since the September 1991 prehearing conference has been to adopt LRMC methodology for implementation in the next utility BCAPs. SoCal and SDG&E's BCAP schedules provide a March 1993 filing date with rates effective October 1, 1993. PG&E's next BCAP filing date is August 1993 with rates scheduled to be effective April 1, 1994.[10]

Several parties advocate we implement LRMC-based rates sooner. The proposed decision requested parties comment on two expedited schedules. One proposal was to consolidate PG&E implementation in SoCal and SDG&E's BCAP proceeding. The other alternative was a PG&E proposal to use a streamlined process of compliance filings and workshops to achieve rate implementation for all three utilities by June 1, 1993.

Several parties' comments to the proposed decision support the June 1st rapid implementation schedule, citing the need to quickly place noncore customer rate decreases in effect and to segment the industrial class into subclasses which more accurately reflect costs of service. SoCal strongly advocates a June implementation schedule for all three utilities. However, SoCal believes its BCAP filing should remain a separate proceeding with the March filing date postponed. SoCal states that it cannot prepare both filings at the same time. PG&E also addresses coordinating proceedings by recommending its August 1993 BCAP should instead be filed one year after SoCal's.

DRA does not support PG&E's June 1 implementation schedule as it effectively eliminates both hearings and briefing. TURN appreciates the Commission's desire to move forward quickly

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10 A delay of several months is common. SoCal and SDG&Es last BCAP decision issued in December 1991 rather than September 1991 and PG&E's recent decision issued in October 1992 rather than March 1992.

with LRMC implementation while expressing concern that any adopted schedule provide adequate time for review and comment by the parties on the utilities submissions. TURN supports a highly expedited implementation schedule along the general lines of that proposed by PG&E only if throughput forecasts and revenue requirements are held constant at the most recently approved levels and no updating or other modifications of the adopted marginal costs will be undertaken unless specifically ordered by the Commission in this decision.

We will move forward with a rapid implementation schedule while carefully ensuring parties have adequate opportunity for review and comment by including a full hearing process and adopting TURN's recommendation on the scope of the proceeding.[11] We also find merit in SoCal's recommendation to retain a separate but coordinated BCAP proceeding. The later SoCal/SDG&E BCAP filing could also accommodate any rate implementation from other gas regulatory changes we are presently considering.

Our adopted schedule is:

PG&E and SoCal implementation filings with full workpapers available	February 1, 1993
SDG&E implementation filing	February 9, 1993
Prehearing Conference	February 11, 1993
Workshop on PG&E filing	February 17, 1993
Workshop - SoCal filing	February 22, 1993
Workshop - SDG&E filing	February 25, 1993
DRA testimony served	March 19, 1993

11 If the utilities' filings do not generate controversy, or if contested issues are resolved in workshops, rate implementation will occur sooner.

Intervenor testimony served	March 31, 1993
Hearings	April 12-23, 1993
Briefs filed	May 23, 1993
Proposed Decision mailed	July 23, 1993
Final Commission decision	August/September
SoCal BCAP filing	August 1, 1993
PG&E BCAP filing	August 1, 1994

The implementation filings will use only the methodology and resource plans adopted in this decision and the most recent Commission approved throughput forecasts and revenue requirements, with the following exceptions:

1. Each utility shall propose segmentation of the industrial class by service level distinctions. Any segmentation proposal that relies on increasing the number of utility functions must show marginal costs for each function consistent with the methods adopted in this decision.

2. If the decision in pending storage proceeding, I.87-03-036, authorizes SoCal to unbundle its storage services, then SoCal should present a subfunctionalized showing in the implementation proceeding. The showing should combine the factual findings in the storage proceeding with the methodology adopted in this decision.

3. In its implementation showing SoCal should develop demand forecasts and corresponding marginal demand measures based on separate marginal demand measures for high-pressure and medium-pressure distribution facilities as adopted in this decision. SoCal should also provide materials showing distribution facilities used in each class.

4. SoCal must reflect its UEG distribution-level deliveries.

8. Forum to Update Resource Plans and Review Adopted LRMC Methodology

The expedited implementation phase outlined in the previous section does not allow for revisions to the adopted resource plans and LRMC methodology. We prefer to review resource planning in general rate cases and LRMC in cost allocation proceedings. This is different from electric, where an annual schedule for ECAC proceedings does not permit us the necessary review period. The next 1993 and 1994 BCAPs (following implementation) is the forum that best provides the three respondents an opportunity to update LRMC methodology.

9. Petition to Modify

CIG, SCUPP, and IP filed a Joint Petition to Modify Decision 90-07-055 and to Limit Scope of Long-run Marginal Cost Proceeding on November 1, 1991. They filed the petition to prevent rates based on LRMC methodology from being implemented in rates as required by D.90-07-055 because "the methodology for gas utilities is in its infancy and any attempt to immediately use LRMC studies for ratemaking purposes is highly premature and would likely lead to substantial rate instability" (p. 2).

Petitioners had requested the Commission modify D.90-07-055 by limiting the scope of this proceeding to developing LRMC studies for use in the gas utilities' long-range planning processes. If this recommendation is rejected, then they requested the opportunity to demonstrate that the existing embedded cost methodology is superior to the use of long-run marginal cost. CIG, SCUPP and IP asserted they "have no confidence that the first, second, or even third iteration of LRMC studies will provide a sufficiently accurate and reliable basis on which to formulate actual rates" (p. 2).

The Division of Ratepayer Advocates (DRA) noted in its response the petitioners are effectively seeking to overturn the October 25, 1991 ALJ ruling that set the scope and schedule for the proceeding. Petitioners advanced the same arguments unsuccessfully in written comments prior to the ruling.

The joint petition is effectively moot. We find the increased pressure of today's competitive market forces do not permit further delay in movement to LRMC-based rate design. The concerns expressed by petitioners have been addressed through our careful selection of methodology. The petition to modify D.90-07-055 is denied.

Findings of Fact

1. This proceeding adopts the first long-run marginal cost methodology for California gas utilities.

2. An appropriately planned system meets customers' needs at the lowest total cost.

3. It is beneficial for each of the utilities to provide explicit reliability objectives for both core and noncore customer groups.

4. In recent years there have been significant changes in PG&E's long-term forecasts of demand growth by class.

5. PG&E and SoCal have not presented any evidence that would indicate that their core customers actually value extreme peak day service highly enough that they would be willing to pay what it costs to provide it.

6. The appropriate forum in which to examine gas industry resource planning under our current regulatory environment is general rate cases.

7. PG&E's local transmission plan is reasonable to use to calculate marginal costs in this proceeding.

8. PG&E's rationale for its backbone transmission and storage plan does not meet a least-cost planning standard.

9. A Line 300 expansion for PG&E is a least-cost approach to estimating marginal costs of transmission.

10. The record supports DRA's classification of Line 6900 expansion as exclusively for SDG&E and exclusive-use facilities are best treated as customer costs.

11. The record also supports DRA's $10 million storage adjustment, as SoCal's witness Phillips testified that additional investment would be dependent on noncore requirements that remain uncertain.

12. SoCal will have sufficient excess capacity on its long-line transmission systems so that SoCal will not have to make capital expenditures to expand this capacity over the entire 15-year transmission planning horizon.

13. SoCal's rates should signal customers that the marginal cost of transmission service is, at this point in time, quite low.

14. It is reasonable to adopt SoCal's planned investments in transmission and storage as set forth in its filing at Table 1, Ex. MC-11 with the exception of DRA's adjustments to Line 6900 treatment and to the decrease in storage withdrawl investment.

15. It is not reasonable to burden SoCal ratepayers with "phantom" charges reflective of the cost of new capacity for the use of existing, sunk capacity that is already in excess of demand.

16. If the PGT/PG&E interconnection facilities receive incremental rate treatment in A.92-04-031, both the PGT/PG&E interconnection costs and the Wheeler Ridge compression facilities, A.90-11-035, should be excluded from SoCal's resource plan. If Kern/Mojave receives rolled-in rate treatment, the most recent adopted estimates for both sets of costs should be used in the implementation filing.

17. No party proposed an adjustment to SDG&E's resource plan and it appears reasonable.

18. Gas transmission is clearly interrelated with storage.

19. Cold-year demand and cold-year peak season demand are the best estimates of the demand-causing transmission costs on the SoCal and PG&E backbone systems, respectively. The compressor fuel

costs on the transmission systems are assigned separately. The unit cost estimate is multiplied by average year throughput for allocation purposes.

20. It is appropriate to designate local transmission systems for PG&E and SDG&E.

21. It is appropriate to designate a high-pressure distribution system for SoCal.

22. Use of a cold year coincident peak month measure for local transmission on SDG&E and PG&E systems best reflects the cost responsibility of customers using the system.

23. Given the similarities between PG&E's local transmission system and SoCal's high-pressure distribution system, use of a cold year coincident peak month measure for SoCal's high-pressure distribution system best reflects the cost responsibility of customers using the system.

24. Cold year winter season reflects best the combination of the storage functions provided by the utilities.

25. The utilities' recommendation of peak day marginal demand measures for their distribution systems better reflect system planning criteria and cost causation.

26. The total investment method is the best measurement for marginal capital costs of transmission and storage costs. The NERA regression approach yielded a strong correlation for distribution systems and is suitable for this function.

27. It is appropriate to adopt for gas LRMC the electric practice established in D.86-08-083 (Pacific Gas and Electric Company (1986) 21 CPUC2d 613, 615) to specifically exclude marketing, service planning, and load management expenses from marginal customer cost expenses, provide for reflection of improvement costs for access equipment of existing customers, and use a weighted customer average rather than investment level for class allocation.

28. Uncollectibles are best treated as a marginal revenue cost.

29. DRA's demand-related O&M methodology, using current period costs, is reasonable on an interim basis.

30. We find reasonable and adopt the following adjustments:

- Reassignment of PG&E's meter and regulators (Accounts 876 and 890) from the customer function to the distribution function based on FERC account descriptions.

- Adjustment of SDG&E's distribution accounts 887 and 892 to reflect labor cost savings from future plastic pipe installations. This is consistent with the capital cost inclusion of technological improvements made in later sections.

- Reassignment of SoCal's mains related costs from the customer function to the distribution function, consistent with our rejection of the minimum distribution system proposal in Section 3.2.

31. It is reasonable to calculate marginal M&S costs using a M&S/MDM rating similar to demand-related O&M.

32. SoCal followed an appropriate approach for calculating marginal A&G expenses. SoCal analyzes the extent to which each account is marginal or nonmarginal and its A&G study shows that approximately 51% of its A&G costs are nonmarginal. PG&E and SDG&E should perform their own system studies applying SoCal's analysis.

33. The record does not support Vernon's request that wholesale customers be excused from any responsibility for 50 percent of the A&G component of the revenue requirement.

34. DRA's recommendation to express marginal general plant costs as a ratio to O&M labor is consistent with our methodology.

35. Working capital is caused by factors broader than plant or rate base.

36. The appropriate methodology for determining the cost of access equipment is DRA's rental market approach as it recognizes the opportunity costs of existing facilities.

37. The proposals of TURN and PG&E provide no persuasive reasons for the Commission to deviate from established electric methodology.

38. The record does not support SoCal's proposal for a minimum distribution system component to marginal customer costs.

39. Zero-intercept methodology has also been unsuccessfully advanced on the electric-side.

40. The record does not support TURN's proposal to exclude a minimum distribution system proxy from customer costs.

41. DRA's Service, Regulator, and Meter (SRM) method draws the "brightest line" between customer and demand related costs, thereby providing a simple, but accurate basis for calculating marginal customer costs.

42. Marginal customer costs also include the dedicated facilities of all large customers.

43. Each respondent utility should ensure that all large customers' dedicated cost assignments are included in its implementation filing.

44. DRA's position that future replacement of existing service lines creates a significantly higher cost than new installation and must be reflected in the marginal cost is also consistent with electric LRMC methodology.

45. It is reasonable for the utilities to keep separate records of replacement costs and new business for the service lines, and to track the trenching share to the gas company for new installations.

46. All methodologies have difficulty in precisely identifying marginal demand-related distribution costs. The best approach is the simpler, bright-line SRM approach, which treats all

SRM facilities as customer related and all distribution facilities as demand related.

47. Exhibit 45 shows 10 of SoCal's 23 UEG customer plants, 8.3% of annual UEG deliveries, are served at distribution level; SoCal's ignorance in this matter causes some concern regarding the fundamental data underlying LRMC.

48. DRA's future replacement cost adjustment for distribution costs is consistent with the methodology and rationale for measurement of marginal customer-costs.

49. We find the argument for a longer period for distribution investments, consisting of 10 years historical and 5 years forecast, to be persuasive.

50. No party in the proceeding, including the respondent utilities, argues that estimates of interstate transmission marginal costs are necessary for retail ratemaking.

51. Adopting an LDC interstate transmission marginal cost is neither necessary nor beneficial.

52. We find the evidentiary record here is insufficient to adopt subfunctionalized marginal storage costs.

53. The Commission's guidelines did not direct energy marginal cost be included in the base-cases because the commodity is unbundled from noncore rates.

54. Consistent with electric energy policy, residual emissions values should be addressed in ratemaking.

55. Electric ratemaking is done by Equal Percentage of Marginal Costs (EPMC) on total.

56. DRA's testimony shows mathematically that PG&E's EPMC by function approach loses all demand-driven marginal cost information.

57. Generally, the marginal costs for transmission and storage are higher than the book-valued capital assets while marginal distribution and customer-costs are quite close to embedded costs.

58. EPMC by total is appropriate for natural gas as well as electric ratemaking as it best preserves the marginal cost signals.

59. Wholesalers' argument that embedded rather than marginal costs better reflect the cost of facilities they utilize is contrary to the fundamental premise of this proceeding.

60. Gas ratemaking differs from electric in that we have divided gas customers into a core/noncore grouping and assigned each different cost responsibilities. It is therefore appropriate to retain existing balancing account treatment for the implementation phase.

61. The record supports continuing to treat Lost and Unaccounted For Gas (LUAF) on an equal cents per therm basis until SoCal and SDG&E submit in the BCAP following implementation the results of their studies and PG&E updates its supporting data.

62. DRA's recommendation that EOR contract revenues, to the extent they exceed EOR marginal cost revenues, should be used to reduce the EPMC scaler is reasonable.

63. The evidence supports service level distinction having a stronger cost foundation than size.

64. Our development of LRMC methodology and the emerging bypass options available to customers provide a different setting than when we considered industrial class segmentation in 1987.

65. Our record here is incomplete; we find it preferable to defer a decision on industrial class segmentation until more detailed information can be examined in the implementation phase.

66. It is reasonable to retain separate customer classes for UEG and cogeneration for the purpose of reflecting cost differences.

67. Commission policy has been to average the rates of core residential and commercial schedules.

68. The issue of core deaveraging is appropriately considered in a cost allocation proceeding, and we will consider it in the 1993 and 1994 BCAPs.

69. The illustrative rate impact of SoCal's deaveraging proposal is far greater than the rate impact of shifting to LRMC.

70. Palo Alto does not provide a compelling reason to add further complexity to the allocation process by treating each individual wholesale customer as a separate class for revenue allocation at this time. In the implementation phase wholesale customers will be allowed to show how they are unfairly harmed by use of EPMC by total.

71. Based upon the illustrative rates in this proceeding, it is not necessary to consider rate caps and rate floors.

72. This is not the forum for the Commission to consider a proposal for discounting of rates on a customer-specific basis.

73. We find insufficient evidence to consider unbundled LRMC for gas gathering, billing, and brokerage costs for core customers.

74. SoCal's request for an interim rate change is not based on any relationship to our LRMC record.

75. It is reasonable for PG&E in its 1994 BCAP filing to update its local transmission resource plan to include at least ten years' of data and to revise its service line length estimates to reflect class cost differences.

76. It is preferable to review resource planning in general rate cases and LRMC in cost allocation proceedings.

77. The concerns raised by and CIG, SCUPP, and IP in their November 1, 1991 Joint Petition to Modify Decision 90-07-055 and to Limit Scope of Long-run Marginal Cost Proceeding have been addressed through our careful selection of methodology.

78. Our adopted implementation schedule is reasonable and protects parties' due process concerns.

Conclusions of Law

1. Natural gas resource plans for PG&E, SoCal, and SDG&E should:

a. Reflect an appropriately planned system that meets customers' needs at the lowest total cost.

b. Use at least a 15-year planning horizon for backbone transmission and storage and at least a 10-year planning horizon for local transmission.

c. Use short-term and long-term forecasts that are thoroughly documented and that specify all economic, load research, and end-use assumptions.

d. Have adequate underlying load data for each customer class. At a minimum, this means hourly load data for UEG customers, daily load data for all noncore customers, and statistically sampled daily load data for core commercial and residential customers.

e. Contain UEG load forecasts that reflect the effects of weather and electric generating unit outages.

f. Contain explicit system design reliability objectives for both core and noncore customers.

2. We should adopt the following marginal demand measures for computing and allocating marginal cost revenues:

a. Backbone Transmission: Cold Year Peak Season for PG&E and Cold Year for SoCal.

b. Local Transmission: Cold Year Coincident Peak Month for PG&E and SDG&E.

c. High-pressure Distribution: Cold Year Coincident Peak Month for SoCal.

c. Storage: Cold year Winter Season for PG&E, SoCal, and SDG&E.

d. Distribution: Peak Day for PG&E and SoCal, and Cool Year Peak Day for SDG&E.

3. The total investment method to calculate the marginal capital costs of transmission and storage and the NERA regression method to calculate the marginal capital costs of distribution should be adopted.

4. We should adopt the following policies for calculating marginal cost expenses and loading factors:

a. Operating and Maintenance provides for customer-related O&M costs to reflect improvement costs for access equipment of existing customers; to use a weighted customer average rather than investment level for class allocation; and to exclude marketing, service planning, load management and uncollectibles. Demand-related O&M costs should be calculated using DRA's proposal of an O&M/MDM ratio. The appropriateness of this ratio will be reevaluated when the respondents submit further marginal analyses and regression studies, as discussed in Section 2.5.1.

b. Materials and Supplies should be calculated using a M&S/MDM ratio similar to demand-related O&M.

c. Administrative and General should be calculated using SoCal's marginal analysis methodology. DRA's recommended proxies should be used for PG&E and SDG&E until they have performed their own system studies.

d. General Plant should be calculated using DRA's GP/O&M labor ratio.

e. Cash Working Capital should not be reflected as a separate loader.

5. We should adopt for marginal customer costs DRA's rental market approach using the service drop-regulator-meter (SRM) investment cost method with adjustments for future replacement and improvement costs.

6. We should adopt for marginal distribution costs DRA's demand-related facilities approach with adjustment for future replacement cost. Data used in the regression analysis should include a time period mix of 10 year historical and 5-year forecasted. SoCal should include its distribution-level UEG load in its implementation filing.

7. It is neither necessary nor beneficial to adopt a methodology for marginal interstate transmission costs.

8. We do not have a sufficient record to subfunctionalize storage costs. If the decision in the storage proceeding authorizes SoCal to unbundle its storage services, then SoCal should present a subfunctionalized showing in the implementation proceeding. The showing should combine the factual findings in the storage proceeding with the methodology adopted here.

9. It is neither necessary nor beneficial to adopt a methodology for marginal energy costs.

10. We will consider addressing the issue of residual emissions values in the next re-evaluation of LRMC methodology.

11. Marginal cost revenues should be scaled to the authorized revenue requirement using an EPMC on total method applied to the base revenues rather than an EPMC by function treatment for any customer class. We should retain existing treatment of balancing accounts and exclude EOR customers from the cost allocation process, applying any EOR revenue credit toward reducing the EPMC scaler.

12. Respondent utilities should work with interested parties to provide the information necessary for us to consider in the implementation phase industrial class segmentation proposals that include service level distinctions.

13. Requests for firm service discounting are before us in other forums, and we are not deciding the issue here; therefore the requests to set cogeneration class rate parity methodology incorporating or excluding discounts are premature.

14. The issue of deaveraging core rates should not be considered until after the implementation phase, and then only in conjunction with a re-examination of core customers' cost and class definitions.

15. Stand-by rates are rate design tools we should consider in today's changing gas industry structure.

16. SoCal's request for an interim rate change should be denied.

17. We should adopt a generic implementation phase for the three utilities. PG&E would use recently adopted throughput forecasts and revenue requirement changes and all three respondents would file in February 1993. Unless directed otherwise in this order, the utilities' filings should use the adopted resource plans and LRMC methodology from this decision and the most recent Commission approved throughput forecasts and revenue requirements.

18. The petition to modify D.90-07-055 should be denied.

19. EPMC by total should be adopted for natural gas ratemaking as it best preserves marginal cost signals.

20. Wholesale customers in the implementation phase should be allowed to show how they are harmed by the use of EPMC by total.

ORDER

IT IS ORDERED that:

1. The Long-run Marginal Cost (LRMC) methodology as set forth in the discussion, findings, and conclusions of this decision is hereby adopted.

2. An expedited implementation proceeding for Pacific Gas and Electric Company, Southern California Gas Company (SoCal), and San Diego Gas & Electric Company (SDG&E) shall be commenced. The implementation filings will use only the methodology and resource plans adopted in this decision and the most recent Commission

approved throughput forecasts and revenue requirements, with the following exceptions:

1. Each utility shall propose segmentation of the industrial class by service level distinctions. Any segmentation proposal that relies on increasing the number of utility functions must show marginal costs for each function consistent with the methods adopted in this decision.

2. If the decision in pending storage proceeding, I.87-03-036, authorizes SoCal to unbundle its storage services, then SoCal should present a subfunctionalized showing in the implementation proceeding. The showing should combine the factual findings in the storage proceeding with the methodology adopted in this decision.

3. In its implementation showing SoCal should present demand forecasts based on separate marginal demand measures for high- and medium- pressure distribution facilities as adopted in this decision.

4. SoCal must reflect its utility electric generation distribution-level deliveries.

5. Wholesalers can show that they are unfairly harmed by Equal Percentage of Marginal Cost on total.

3. Resource planning shall be updated in general rate cases. LRMC shall be updated in each utility's cost allocation proceeding following the implementation proceeding. SoCal and SDG&E shall file August 1, 1993. PG&E shall file August 1, 1994

4. The Joint Petition to Modify Decision (D.) 90-07-055 filed November 1, 1991 is denied.

5. This proceeding shall remain open for the implementation phase.

This order is effective today.

Dated December 16, 1992, at San Francisco, California.

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

PB

MASTER LIST
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A87-01-037/A87-04-040
RVSD: 11/12/92//CORR: 11/12/92
DOC. I.D. #X01529

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(END OF APPENDIX A)

APPENDIX B

Parties Participating in the Hearing Process

PG&E	Pacific Gas And Electric Company
SDG&E	San Diego Gas & Electric Company
SoCalGas	Southern California Gas Company
CCC	California Cogeneration Council
CIG	California Industrial Group, California Leaugue of Food Processors, and California Manufacturers Association
Marketers Group	California Gs Marketers Group
Long Beach	City of Long Beach
Palo Alto	City of Palo Alto
Vernon	City of Vernon
DRA	Division of Ratepayer Advocates, CPUC
IEP	Independent Energy Producers Assoc. and Geothermal Resources Assoc.
IP	Indicated Producers
McFarland	McFarland Energy, Inc
Edison	Southern California Edison Compay
SCUPP	Southern California Utility Power Pool and Imperial Irrigation District
TURN	Toward Utility Rate Normalization

(END OF APPENDIX B)

		Residential	Small Commercial	Large Commercial	Subtotal Core	IND/P2B	UEG	COGEN	Wholesale	Total
MARGINAL CUSTOMER COSTS										
Annual Marginal Customer Cost		$143	$231	$2,476		$5,619	$7,172,562	$7,957	$4,462	
DEMAND-RELATED MARGINAL COSTS										
Distribution	$92.60									
Storage	$0.1078									
Local Transmission	$1.4728									
Backbone Trans Facilities	$0.2848									
Backbone Trans Fuel	$0.0221									
DEMAND MEASURES (mdth)	(Index)									
# of Customers-New	1	56,294	2,247	5	58,546	9	0	1	0	58,556
# of Customers-Total	2	3,329,962	198,039	506	3,528,507	897	1	129	36	3,529,570
Cold Winter Day Distrib Dem	3	1,541	500	77	2,118	223	0	56	0	2,397
Cold Winter Day Local Trans	4	1,541	500	77	2,118	507	500	166	90	3,381
Cold Season	5	158,084	47,270	10,226	215,580	66,417	59,769	23,871	9,518	375,155
CY Noncoinc. Peak Month	6	41,356	11,322	2,421	55,099	8,334	0	1,744	0	65,176
CY Coinic. Peak Month	7	41,356	11,322	2,421	55,099	13,880	9,198	4,397	1,970	84,544
CY Coinic. Peak Month Loc T	8	44,551	12,197	2,608	59,356	14,952	9,909	4,737	2,122	91,076
Cold Year Loc Trans	9	248,909	87,108	19,461	355,477	169,396	184,985	62,105	18,464	790,427
Cold Year Backbone	10	240,408	84,133	18,796	343,337	163,610	178,667	59,984	17,834	763,432
Average Year	11	218,030	80,661	18,171	316,862	168,086	188,418	61,302	16,270	750,936
Ave Year Adjust. for Shrink	12	207,810	76,659	17,241	301,709	163,989	184,552	60,170	15,988	726,407
MARGINAL COST REVENUE RESPONSIBILITY ($000)										
Customer-Total	2	$474,851	$45,723	$1,253	$521,828	$5,041	$7,173	$1,026	$161	$535,228
Distribution	3	$142,703	$46,302	$7,131	$196,136	$20,651	$0	$5,186	$0	$221,972
Local Transmission	8	$65,617	$17,964	$3,841	$87,423	$22,023	$14,594	$6,976	$3,126	$134,141
Backbone Transmsn Coinc.	5	$45,019	$13,461	$2,912	$61,392	$18,914	$17,021	$6,798	$2,711	$106,836
Backbone Transmsn Noncoinc	11	$4,814	$1,781	$401	$6,996	$3,711	$4,160	$1,354	$359	$16,581
Storage	5	$17,041	$5,096	$1,102	$23,239	$7,160	$6,443	$2,573	$1,026	$40,441
Total Marginal Rev. Responsibility		$750,046	$130,328	$16,640	$897,014	$77,499	$49,391	$23,914	$7,382	$1,055,200
Marg Cost Rate (No Interstate)		36.09	17.00	9.65	29.73	4.73	2.68	3.97	4.62	14.53

	Residential	Small Commercial	Large Commercial	Subtotal Core	IND/P2B	UEG	COGEN	Wholesale	Total
REVENUE RECONCILIATION ($000)									
Present Revenue Responsib.	$767,859	$298,384	$48,618	$1,114,860	$185,307	$156,869	$51,144	$15,188	$1,523,369
Present Transport Rates	37.0	38.9	28.2	37.0	11.3	8.5	8.5	9.5	21.0
Embedded Base Revenue									$1,115,596
EPMC Factor							Base Rev. Req. Only:		1.06
Base Revenue Responsibility at EPMC	$792,976	$137,787	$17,593	$948,356	$81,935	$52,218	$25,282	$7,805	$1,115,596
Other Fixed Costs	$160,897	$63,329	$14,197	$238,422	$69,623	$68,919	$23,754	$7,055	$407,773
Total	$953,873	$201,116	$31,790	$1,186,778	$151,558	$121,137	$49,036	$14,860	$1,523,369
Avg. Rate (cents/th) No Class Avg.	45.90	26.24	18.44	39.34	9.24	6.56	8.15	9.29	20.97
Equalized Marginal Rev. Responsib.	$817,425	$327,533	$41,820	$1,186,778	$151,558	$128,333	$41,840	$14,860	$1,523,369
Avg. Rate (cents/th) Equalized Revs	39.3	42.7	24.3	39.3	9.2	7.0	7.0	9.3	21.0
% Change from Present Rates	6.46%	9.77%	-13.98%	6.45%	-18.21%	-18.19%	-18.19%	-2.16%	0.00%
SAPC 0.00%									
Cap 100.00%									
Floor 100.00%									
Core Gas 25.35 1									
Capped Revenue Responsibility	$817,425	$327,533	$41,820	$1,186,778	$151,558	$128,333	$41,840	$14,860	$1,523,369
Revenue Difference	$0	$0	$0		$0	$0	$0	$0	$0
Weighted Shortfall Responsibility	$817,425	$327,533	$41,820		$151,558	$128,333	$41,840	$14,860	$1,523,369
Shortfall Allocator	1	1	1		1	1	1	1	
Shortfall Allocation	$0	$0	$0		$0	$0	$0	$0	$0
Final Revenue Responsibility	$817,425	$327,533	$41,820	$1,186,778	$151,558	$128,333	$41,840	$14,860	$1,523,369
Percent Change	6.46%	9.77%	-13.98%	6.45%	-18.21%	-18.19%	-18.19%	-2.16%	0.00%

		Residential	Sml Com GN-10	Lrg Comm GN-20	Subtotal Core	Com/Ind GN-30	UEG	COGEN	Long Beach	SDG&E	Total
MARGINAL CUSTOMER COSTS											
Annual Marginal Customer Cost		$147	$454	$6,829		$16,039	$346,869	$10,851	$260,947	$841,768	
DEMAND-RELATED MARGINAL COSTS											
Distribution	$71.76										
Storage	$0.2529										
Local Transmission	$0.0000										
Transmission Coincident	$0.0788										
Transmission Noncoincident	$0.0136										
DEMAND MEASURES (mdth)	(Index)										
# of Customers-New	1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
# of Customers-Total	2	4,526,464	220,363	558	4,747,385	832	8	262	1	1	4,748,489
Cold Winter Day Distrib Dem	3	0	0	0	0	0	0	0	0	0	0
Cold Winter Day Local Trans	4	0	0	0	0	0	0	0	0	0	0
CY Winter Season	5	170,382	43,665	5,828	219,875	36,136	50,259	21,661	11,247	49,379	388,557
CY Peak Month	6	48,413	11,262	1,435	61,110	8,644	0	2,511	0	0	72,265
CY Coinic. Peak Month	7	0	0	0	0	0	0	0	0	0	0
CY Coinic. Peak Month Loc T	8	0	0	0	0	0	0	0	0	0	91,076
Cold Year Peak Day	9	2,863	601	134	3,598	245	0	92	0	0	3,935
Cold Year	10	320,190	100,639	14,506	435,335	106,808	185,067	65,342	30,636	123,595	946,783
Average Year	11	285,397	93,547	14,069	393,012	105,794	184,224	64,789	30,248	113,084	891,150
Ave Year Adjust. for Shrink	12	285,397	93,547	14,069	393,012	105,794	184,224	64,789	30,248	113,084	891,150
MARGINAL COST REVENUE RESPONSIBILITY ($000)											
Customer-Total	2	$663,216	$99,963	$3,811	$766,990	$13,344	$2,775	$2,843	$261	$842	$787,054
Distribution	9	$205,445	$43,127	$9,616	$258,187	$17,581	$0	$6,602	$0	$0	$282,370
Local Transmission	8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Backbone Transmission Coinc	10	$25,236	$7,932	$1,143	$34,311	$8,418	$14,586	$5,150	$2,415	$9,741	$74,620
Backbone Transmission Nonco	11	$3,889	$1,275	$192	$5,355	$1,442	$2,510	$883	$412	$1,541	$12,143
Storage	5	$43,085	$11,042	$1,474	$55,600	$9,138	$12,709	$5,477	$2,844	$12,486	$98,255
Total Marginal Revenue Responsibili		$940,870	$163,338	$16,235	$1,120,443	$49,923	$32,580	$20,955	$5,932	$24,610	$1,254,443
Marg. Cost Rate (No Interstate) c/T		32.97	17.46	11.54	28.51	4.72	1.77	3.23	1.96	2.18	14.08

	Residential	Sml Com GN-10	Lrg Comm GN-20	Subtotal Core	Com/Ind GN-30	UEG	COGEN	Long Beach	SDG&E	Total
REVENUE RECONCILIATION ($000)										
Present Revenue Responsib.	$1,118,652	$379,109	$42,704	$1,540,465	$133,504	$148,694	$64,960	$19,355	$79,881	$1,986,859
Present Transport Rates	39.20	40.53	30.35	39.20	12.62	8.58	8.58	6.40	7.06	22.30
Embedded Base Revenue										1,458,023
EPMC Factor							Base Rev. Req. Only:			1.16
Base Revenue Responsibility at EPMC	$1,093,561	$189,845	$18,870	$1,302,277	$58,024	$37,868	$24,356	$6,894	$28,604	$1,458,023
Other Fixed Costs	$238,876	$75,519	$11,068	$325,463	$42,849	$73,597	$25,177	$12,023	$50,523	$529,632
Total Revenue Responsibility at EPM	$1,332,437	$265,364	$29,938	$1,627,740	$100,873	$111,465	$49,533	$18,917	$79,127	$1,987,655
Avg. Rate (cents/th) No Class Avg.	46.69	28.37	21.28	41.42	9.53	6.05	7.65	6.25	7.00	22.30
Equalized Marginal Rev. Responsib.	$1,182,029	$405,414	$40,296	$1,627,740	$100,873	$119,109	$41,889	$18,917	$79,127	$1,987,655
Avg. Rate (cents/th) Equalized Reve	41.42	43.34	28.64	41.42	9.53	6.47	6.47	6.25	7.00	22.30
% Change from Present Rates	5.67%	6.94%	-5.64%	5.67%	-24.44%	-24.65%	-24.65%	-2.26%	-0.94%	0.04%
SAPC 0.00%										
Cap 100.00%										
Floor 100.00%										
Core Gas $1.99 1										
Capped Revenue Responsibility	$1,182,029	$405,414	$40,296	$1,627,740	$100,873	$119,109	$41,889	$18,917	$79,127	$1,987,655
Revenue Difference	$0	$0	$0		$0	$0	$0	$0	$0	$0
Weighted Shortfall Responsibility	$1,182,029	$405,414	$40,296	$1,627,740	$100,873	$119,109	$41,889	$18,917	$79,127	$1,987,655
Shortfall Allocator	1	1	1	1	1	1	1	1	1	
Shortfall Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Adjusted Revenue Responsibility	$1,182,029	$405,414	$40,296	$1,627,740	$100,873	$119,109	$41,889	$18,917	$79,127	$1,987,655
	5.67%	6.94%	-5.64%	5.67%	-24.44%	-24.65%	-24.65%	-2.26%	-0.94%	0.04%

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	Residential	Sml Comm GN-1	Lrg Comm GN-2	Subtotal Core	Ind/P2b	Cogen	UEG	Total
REVENUE RECONCILIATION ($000)								
Present Revenue Responsib	$152,772	$24,661	$2,284	$179,717	$10,720	$23,886	$36,846	$251,169
Present Transport Rates	40.30	23.94	18.33	40.30	15.86	10.38	10.38	22.86
Embedded Base Revenues								$188,808
EPMC Factor						Base Revenue Req. Only:		0.92
Base Revenue Responsibility at EPMC	$130,899	$17,319	$1,344	$149,562	$5,007	$13,246	$20,994	$188,808
Other Fixed Costs	$25,434	$7,816	$934	$34,184	$3,081	$7,332	$17,764	$62,361
Total Rev Responsib at EPMC	$156,332	$25,135	$2,278	$183,746	$8,088	$20,577	$38,758	$251,169
Avg. Rate. No Class Averaging	47.31	24.40	18.28	41.21	11.96	12.82	9.13	22.86
Equalized Marg Rev. Responsib.	$136,168	$42,443	$5,135	$183,746	$8,088	$16,273	$43,062	$251,169
Average Rate Equalized Revenue	41.21	24.40	18.28	41.21	11.96	10.14	10.14	22.86
%Change from Present Rates	2.24%	1.92%	-0.25%	2.24%	-24.55%	-2.30%	-2.30%	0.00%
SAPC 0.00%								
Cap 100.00%								
Floor 100.00%								
Core Gas $1.94 1								
Capped Revenue Responsibility	$156,332	$25,135	$2,278	$183,746	$8,088	$20,577	$38,758	$251,169
Revenue Difference	$0	$0	$0	$0	$0	$0	$0	$0
Weighted Shortfall Responsibility	$156,332	$25,135	$2,278	$183,746	$8,088	$20,577	$38,758	$251,169
Shortfall Allocator	1	1	1	1	1	1	1	
Shortfall Allocation	$0	$0	$0	$0	$0	$0	$0	$0
Final Revenue Responsibility	$156,332	$25,135	$2,278	$183,746	$8,088	$20,577	$38,758	$251,169
Percent Change	2.33%	1.92%	-0.25%	2.24%	-24.55%	-2.30%	-2.30%	0.00%

* Transmission costs are the SDG&E transmission cost, plus costs for the SoCal Transmission system

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		Residential	Sml Comm GN-1	Lrg Comm GN-2	Subtotal Core	Ind/P2b	Cogen	UEG	Total
UNIT MARGINAL COSTS									
Customer costs		$121	$220	$1,017		$1,171	$1,027	$1,760,026	
Distribution	$124.54								
Transmission Fuel	$0.0046								
Transmission Facilities	$3.3731								
Storage	$0.2592								
DEMAND MEASURES (mdth)	(index)								
Number of Customers	1	673,688	27,793	25	701,506	67	63	1	701,637
CY Coinc. Peak Mo.	2	61,287	13,581	1,275	76,143	5,806	14,612	30,930	127,490
CY NCoinc Pk.Mo.	3	61,287	13,581	1,275	76,143	5,824	14,899	39,090	135,955
Average Year Mth	4	330,442	102,998	12,461	445,901	67,607	160,450	424,589	1,098,547
CY Peak Season	5	220,577	53,137	4,994	278,708	29,496	62,656	119,875	490,735
Cool Year Peak Day	6	2,760	540	70	3,370	210	620	590	4,790
Adjust Ave Year	7	330,442	102,998	12,461	445,901	67,607	160,450	424,589	1,098,547
MARGINAL COST REVENUE RESPONSIBILITY ($000)									
Customer	1	$81,516	$6,114	$25	$87,656	$78	$65	$1,760	$89,559
Distribution	6	$34,374	$6,725	$872	$41,971	$2,615	$7,722	$7,348	$59,656
Transmission	2	$20,673	$4,581	$430	$25,683	$1,958	$4,929	$10,433	$43,003
Transmiss Ave	4	$152	$47	$6	$205	$31	$74	$195	$505
Storage	5	$5,717	$1,377	$129	$7,224	$765	$1,624	$3,107	$12,720
Total Marg Rev. Resp		$142,432	$18,845	$1,462	$162,740	$5,448	$14,413	$22,843	$205,444
Marg Cost Rate (No Interstate)		43.10	18.30	11.74	36.50	8.06	8.98	5.38	18.70

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DISTRIBUTION MARGINAL COSTS COMPARISON
1992 $

		SDG&E		PG&E		SCG	
MARGINAL COST OF FACILITIES							
Marginal Investment Cost (per peak day)	$/MCFD	1270.58 *		820.29 *		644.21 *	
Marginal Investment Cost (per cold year peak month)	$/MCF/mo	37.01		33.59		35.65	
Annualized Investment Cost	$/MCF/pk day		108.76		70.22		55.14
LOADERS UNITIZED ACCORDING TO COLD-YEAR PEAK DAY							
Total Distr. O&M Expenses	$/YR	3,254,000		33,169,000		34,103,000	
Marginal O&M Expense	$/MCF/pk day	8.2172		12.4275		8.5279	
Administrative & General	$/MCF/pk day	2.8842		2.8583		2.8696	
General Plant	$/MCF/pk day	0.7042		2.5837		0.8119	
Materials & Supplies	$/MCF/pk day	3.9757		4.5179		4.4048	
BASE CASE: Total Loaders	$/MCF/pk day		15.78		22.39		16.61
TOTAL MARGINAL COST (Facilities+Loaders)	$/MCF/pk day		124.54		92.60		71.76
MARGINAL DEMAND MEASURE							
Avg. Year Annual Dist. Throughput 1992	MCF/YR	99,138,100		391,354,000		509,664,927	
Cold Year Peak Month Distr. Throughput 1992	MCF/mo	13,595,542		65,177,000		72,264,654	
Peak Day Dist. Demand 1992	MCFD	396,000		2,669,000		3,999,000	
LOADING FACTORS							
RECC		0.0856		0.0910		0.1081	
A&G		0.3510		0.2300		0.3365	
GPLF		0.0857		0.2079		0.0952	

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ILLUSTRATIVE BACKBONE TRANSMISSION MARGINAL COSTS
1992 $

		PG&E		SCG	
MARGINAL COST OF FACILITIES					
Marginal Investment Cost Per Marginal Demand Measure (MDM)	$/MDM	2.50		0.32	
Annualized Investment Cost	$/MDM		0.2249		0.0320
LOADERS					
Trans. O&M Expenses	$/YR	14,791,000		33,345,371	
Marginal O&M Expense	$/MDM	0.0394		0.0304	
Administrative & General	$/MDM	0.0091		0.0102	
General Plant	$/MDM	0.0082		0.0029	
Materials & Supplies	$/MDM	0.0032		0.0033	
Total Loaders	$/MDM		0.0599		0.0468
SUBTOTAL MC (facilities+Loaders)	$/MDM		0.2848		0.0788
Fuel Cost	$/DTH		0.0221		0.0136
MARGINAL DEMAND MEASURES (MDM)					
Avg. Year Annual System Throughput 1992	DTH/YR	730,907,000		1,039,367,000	
Cold Year Peak Month System Throughput 1992	MCF/MO	N/A		N/A	
Cold Winter Season System Throughput 1991-1992	DTH/CWS	375,155,000		N/A	
Cold Year Annual System Throughput 1992	DTH/CYR	763,432,000		1,095,900,000	
LOADING FACTORS					
RECC		0.0900		0.0997	
A&G		0.2300		0.3365	
GPLF		0.2079		0.0952	

LOADERS UNITIZED ACCORDING TO MDM FOR EACH UTILITY.
FUEL COSTS ALLOCATED ON AVERAGE ANNUAL THROUGHPUT BASIS.

14-Dec-92 I.86-06-005/CACD/PWF

LOCAL TRANSMISSION MARGINAL COSTS
1992 $

		PG&E		SDG&E	
MARGINAL COST OF FACILITIES					
Marginal Investment Cost Per Marginal Demand Measure (MDM) 1/	$/MDM	10.78		23.92	
Annualized Investment Cost	$/MDM		0.9814		1.9540
LOADERS					
Local Trans. O&M Expenses	$/YR	27,470,000		3,668,162	
Marginal O&M Expense	$/MDM	0.3068		0.2877	
Administrative & General	$/MDM	0.0706		0.1010	
General Plant	$/MDM	0.0638		0.0247	
Materials & Supplies	$/MDM	0.0504		0.0255	
Total Loaders	$/MDM		0.4914		0.4388
SUBTOTAL MC (facilities+Loaders)	$/MDM		1.4728		2.3928
1/ MARGINAL DEMAND MEASURES (MDM)					
Avg. Year Annual System Throughput 1992	DTH/YR	730,907,000		110,908,700	
Cold Year Peak Month System Throughput 1992	DTH/MO	89,551,000		12,749,022	
LOADING FACTORS					
RECC 3/		0.0910		0.0817	
A&G		0.2300		0.3510	
GPLF		0.2079		0.0857	

14-Dec-92 I.86-06-005/CACD/PVF

ILLUSTRATIVE MARGINAL STORAGE COSTS

1992$

		SDG&E*	PG&E	SCG
MARGINAL COST OF FACILITIES				
Marginal Investment Cost Per Marginal Demand Measure	$/MDM (MDM)	N/A	0.91	1.54
Annualized Investment Cost	$/MDM	0.2592	0.0827	0.1771
LOADERS				
Total Storage O&M Expenses	$/YR	N/A	5,574,284	22,315,709
Marginal O&M Expense	$/MDM	N/A	0.0148	0.0495
Administrative & General	$/MDM	N/A	0.0034	0.0167
General Plant	$/MDM	N/A	0.0031	0.0047
Materials & Supplies	$/MDM	N/A	0.0037	0.0049
Total Loaders	$/MDM	N/A	0.0251	0.0757
TOTAL MC (Facilities+Loaders)	$/MDM	0.2592	0.1078	0.2529
MARGINAL DEMAND MEASURES (MDM)				
Ave. Year Annual System Throughput 1992	DTH/YR	109,854,700	730,907,000	1,039,367,000
Cold Winter Season System Throughput 1991-1992	DTH/CWS	49,073,500	375,653,000	450,791,000
LOADING FACTORS				
RECC		N/A	0.0906	0.1153
A&G		N/A	0.2300	0.3365
GPLF		N/A	0.2079	0.0952

* SDG&E storage costs reflect costs from the SoCal system

(END OF APPENDIX A)