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Decision 97-04-082 April 23, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of Southern California Gas Company (U 940-G) for Authority to Review its Rates Effective January 1, 1997, in its Biennial Cost Allocation Proceeding.	Application 96-03-031 (Filed March 15, 1996)
In the Matter of the Application of San Diego Gas & Electric Company (U 902-G) for Authority to Revise its Rates Effective January 1, 1997 in its Biennial Cost Allocation Proceeding.	Application 96-04-030 (Filed April 15, 1996)

(See Appendix A for appearances.)

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OPINION

Summary

In this decision we adopt rates for the coming period through July 31, 1999 for customers of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) based on the utilities' Biennial Cost Allocation Proceeding (BCAP) applications.

We adopt an annual revenue requirement increase of $2.66 million for SoCalGas, an annual revenue requirement decrease of $25.65 million for SDG&E, and direct SoCalGas to refund directly to customers any overcollection in its Purchased Gas Account. In this proceeding, we allocate the base revenue requirement between customer classes using long-run marginal cost (LRMC) methodology and reexamine the allocation of interstate pipeline capacity costs based on SoCalGas' relinquishment of 750 million cubic feet a day (MMcf/d) of interstate pipeline capacity reservations.

We find that SoCalGas' interstate pipeline capacity relinquishments will help alleviate its stranded cost obligations that arise from the restructuring of the natural gas industry over the past ten years. In this decision, we maintain our established policy framework and allocate stranded interstate pipeline capacity charges to the core and noncore based on their respective capacity reservations. The core cost responsibility will include base transportation rates in El Paso and Transwestern pipeline tariffs and any surcharges on the base rates which are already authorized or may be authorized in the future to mitigate the pipelines' risk of unsubscribed capacity. In addition, we maintain our allocation of ITCS to the core capped at an amount equal to 10% of the core capacity reservation.

In our review of the long-term resource plans submitted by each applicant in support of its LRMC proposal, we find serious concerns that go beyond the scope of this proceeding to resolve.

We also find several additional areas that warrant further review including storage operations and core deaveraging. Fundamental questions regarding the validity of LRMC methodology and these additional issues will be examined as determined by a procedural roadmap issued following our upcoming Natural Gas Strategy. In that roadmap, staff may recommend either a future BCAP or another proceeding as the proper forum to address these issues. In the interim, we find the specific ratemaking treatment to be given SoCalGas' Line 6900 and Line 6902 transmission projects should be further investigated and fully resolved prior to final Commission action on the proposed Pacific Enterprises/Enova merger. For SDG&E, we find it did not provide the necessary justification for its resource plan and direct it to supplement its filing within 6 months.

This decision finds that SoCalGas' and SDG&E's transportation rates will change as follows:

SOUTHERN CALIFORNIA GAS COMPANY

PD-1997

Comparison Proposed of Rate Changes (¢/Therm)*

	Proposed Transportation Rates							
	Base Revenue	% change	Other Op. Costs & Balancing Accts	% change	Interstate Pipeline Capacity Costs[a]	% change	Total	% change
Core:								
Residential	42.672	(3.5)	4.731	1.9	4.534	10.8	50.835	1.5 **
Small Commercial	26.797	7.3	3.545	(8.1)	4.534	10.8	37.985	(9.0) **
Large Commercial	9.548	3.5	3.714	3.2	4.534	10.8	17.795	5.2
Total Core[b]	38.234	(1.1)	4.439	1.6	4.534	10.8	47.208	0.0
Noncore:								
Commercial/Industrial	4.795	9.2	1.849	19.0	1.300	(27.9)	7.944	2.5
Cogen	2.110	(4.5)	1.631	(1.4)	1.300	(27.9)	4.905	(7.4)
UEG	1.953	12.6	1.596	(0.7)	1.300	(27.9)	4.905	(7.4)
Wholesale	2.270	(2.8)	1.472	(2.9)	1.294	19.2	5.036	1.9
Total Noncore[c]	3.323	5.9	1.497	5.9	1.299	(8.7)	6.031	-3.0
System Total:[d]	16.497	(7.8)	2.614	(4.9)			22.608	(0.01)

* Based on rates, effective 4/16/96 (Advice Letter 2492).
** Reflects core averaging
[a] Average brokered capacity rate for noncore in 1996 was $.013 on El Paso (California Natural Gas Market Review, Vol. 4, Issue 8, 12/96).
[b] Includes Nonres A/C and Gas Engines.
[c] Includes EOR and Unbundled Noncore Storage.
[d] Includes Zone Rate Credit.

SAN DIEGO GAS & ELECTRIC COMPANY

Alternate-1A-3

Comparison of Proposed Rate Changes (¢/Therm)*

Proposed Transportation Rates with Deaveraging and parity effects

	Base Revenue	% change*	Other Op. Costs & Balancing Accts	% change*	Interstate Pipeline Capacity Costs	% change*	SoCal ITCS	% Change*	Total	% change**
Core:										
Residential	38.86	-4.07	5.43	23.75	1.54	-52.54	1.24	292.75	53.53	-3.38
Small Commercial	34.28	-9.58	3.55	-30.49	1.54	-52.55	1.24	293.28	23.00	-10.03
Large Commercial	19.36	12.27	4.06	-25.01	1.55	-52.47	1.24	240.75	15.58	-30.96
Total Core	37.26	-5.17	4.92	97.23	1.54	-52.55	1.24	290.80	44.97	-5.22
Noncore:										
Commercial/Industrial	5.50	-19.48	2.00	-64.69	1.32	-3.43	1.24	-36.17	10.06	-38.30
Cogen	2.54	17.43	2.64	-65.31	1.32	-34.18	1.24	-36.17	7.74	-25.15
UEG	2.44	-1.77	2.80	-26.25	1.28	-34.25	1.23	-36.14	7.75	-14.75
Total Noncore	2.86	9.19	2.64	-45.72	1.29	-34.33	1.24	-36.20	8.03	-22.69
System Total:	17.19	0.25	3.59	-23.06	1.41	-46.72	1.24	1.41	23.44	-6.51

* Based on current rates effective 1/1/96 filed by Advice Letter 991-G-A on 12/28/95.

**The total % change does not include commodity charges as Appendix C page 1 and the UEG % change is adjusted for the change in throughput.

I. Background

A. Overview

This decision addresses the consolidated BCAP applications of SoCalGas and SDG&E to revise their gas rates and tariffs for a 31-month period, from January 1, 1997 through July 31, 1999.[1] The BCAP is the proceeding in which we allocate the applicants' base revenue requirement between customer classes, amortize balancing accounts, adopt new demand and cost of gas forecasts, and determine the rate design under which the applicants will recover their costs in the coming period. The proceeding primarily addresses nongas costs of service. This is the first BCAP in which we will not set a core procurement rate because core gas prices are now set on a monthly basis pursuant to D.96-05-071 for SDG&E and D.96-08-037 for SoCalGas. As a result of our restructuring of the natural gas industry over the last ten years, noncore customers are permitted to procure their own gas supplies and purchase interstate gas transportation in competitive markets.

SDG&E is a wholesale customer of SoCalGas. Therefore, we first address SoCalGas' Application (A.) 96-03-031. Based on the nongas costs of service allocated to SDG&E in SoCalGas' BCAP, we set rates for SDG&E's customers in SDG&E's application, A.96-04-030. Both applicants request their rates be effective on the same date.

1 SoCalGas requests an extension of the normal 24-month BCAP period in order to have its BCAP rates coincide with the full period during which it is subject to the conditions of the Global Settlement, a comprehensive stipulation and settlement agreement adopted, with modifications, by the Commission in Decision (D.) 94-07-064.

B. Procedural Background

In A.96-03-031 filed on March 15, 1996, SoCalGas seeks a $137.7 million annual decrease in rates over the coming 31 months to reflect (1) the allocation among customers of the nongas costs of service previously authorized by the Commission for recovery in rates; (2) the amortization of the balances as of December 31, 1996 in various balancing, tracking and memorandum accounts previously authorized by the Commission; and (3) the forecasted cost of purchased gas for core customers.[2]

SoCalGas states its application is consistent with the terms of the modified Global Settlement approved by the Commission in D.94-04-088 and D.94-07-064 and covers the remainder of the five-year term of the settlement, which began in 1994 and extends through July 31, 1999. The Global Settlement resolved the most contentious issues pending before the Commission with regard to SoCalGas, including: allocation of over $1 billion in gas costs which exceed market prices for supplies purchased from SoCalGas affiliates Pacific Interstate Transmission Company (PITCO) and Pacific Offshore Pipeline Company (POPCO); SoCalGas shareholder responsibility for noncore discounts and for noncore throughput; three pending gas cost reasonableness reviews; a gas cost incentive mechanism to replace reasonableness reviews; and the base rate attrition formula for 1995 and 1996.

The specific provisions of the Global Settlement SoCalGas cites as relevant to its BCAP are the adoption of adjusted 1991

2 This revenue requirement is shown on revised Table C.1, filed April 25, 1996. SoCalGas' original Table C.1 reflected a rate decrease of $147.9 million due to a mathematical error made in preparing the original filing. SoCalGas amended its filing and renoticed its application to reflect the corrected level of authorized margin. (See April 26, 1996 Prehearing Conference (PHC) Transcript, page 7.)

recorded throughput and the use of LRMC methodology for cost allocation and ratemaking purposes.

In A.96-04-030 filed on April 15, 1996, SDG&E proposes a annual rate decrease of $42 million based on its BCAP filing for the same 31-month period requested by SoCalGas. It also requests the Commission consolidate its proceeding with SoCalGas'.

A prehearing conference on both applications was held on April 26, 1996. Because the rates of SDG&E are dependent upon the rates set for SoCalGas, the two applications were consolidated for hearing with SDG&E's procedural schedule set to follow SoCalGas' schedule. Hearings were held in San Francisco from August 1-29 on SoCalGas' application and from September 3-5, 1996 on SDG&E's application. Opening briefs were filed September 27 and October 11, 1996 for SoCalGas and SDG&E, respectively. Reply briefs were filed October 15 and October 22, 1996. The consolidated case was submitted on October 22, 1996.

In its update filing of October 15, 1996, SoCalGas requests an overall rate decrease of only $55.7 million, down from $137.7 million, due to changes in the forecasted level of its balancing accounts at December 31, 1996. SDG&E in its update filing of October 25, 1996 reflects an overall decrease of $26.98 million, down from a $42 million decrease; it also requests the Commission not pass through to core customers the updated balances at this time as it would lead to a residential rate increase under SDG&E's rate design proposal.

These filings raise the issue of adequate notice because both update filings request a revenue requirement higher than the amount noticed for the applications. On November 8, 1996, an administrative law judge (ALJ) ruling set a procedural schedule for applicants to address the issue and for interested parties to indicate any concerns raised by applicants' responses and, if appropriate, the procedural remedy they recommend.[3]

In their comments, both applicants state that the update increases are attributable exclusively to revised forecasts of regulatory account balances that are under a balancing account mechanism that ensures the recovery of shortfalls as a matter of settled Commission policy. The Office of Ratepayer Advocates (ORA) supports this position, stating that the increases fall within the parameters of the notice exception granted under Public Utilities Code § 454(a). ORA does not support SDG&E's request to defer collection of its update balances because this proposal would result in core ratepayers unnecessarily paying interest charges on the balances for all of 1997.

We find the update filings are adequately noticed. Further, we agree with ORA that SDG&E should not defer collection of its regulatory balances. We will set rates in this proceeding to recover the revenue requirement shown in the update filings.

In future BCAPs, applicants should specifically discuss in their update filings any increase in revenue requirement from that noticed in their applications and whether additional notice has been provided.

Active parties in A.96-03-031 are: the applicant, SoCalGas; Alenco Gas Services, Inc. (Alenco); the California Cogeneration Council and Watson Cogeneration Company (CCC/Watson); the California Department of General Services (DGS); the California Industrial Group and California Manufacturers Association (CIG/CMA); the City of Long Beach (Long Beach); Enron Capital and

3 This ruling also requested SDG&E to provide additional data to enable the Commission and parties to assess the significance of SDG&E's marked downward adjustment to its 1996 core sales figure based on an additional six months of actual data. SDG&E provided the requested data and no party requests further action.

Trade Resources (Enron); Enserch Energy Services, Inc. (Enserch); ORA, formerly the Division of Ratepayer Advocates; Pacific Gas and Electric Company (PG&E); PLB Management, LLC (PLB); SDG&E; Save Our Services Coalition (SOS); Southern California Edison Company (Edison); Southern California Utility Power Pool and Imperial Irrigation District (SCUPP/IID); The Utility Reform Network, formerly Toward Utility Rate Normalization (TURN); and the Western Mobilehome Parkowners Association (WMA).

Active parties in A.96-04-030 are: the applicant, SDG&E; ORA; Enron; The Nutrasweet Kelco Company (Kelco); and The Roadrunner Club Association, Inc. (Roadrunner Club).

In the following sections, we summarize the parties' positions and discuss the reasoning behind our conclusions. The record in this proceeding is voluminous, consisting of 147 exhibits and a hearing transcript of 2826 pages.[4] Exhibit 122 provides a summary of the issues and parties' positions in SoCalGas' BCAP and Exhibit 222 contains a summary for SDG&E's BCAP. In this decision, we concentrate on the chief points of contention, and do not try to address every nuance in individual positions.

C. 311 Comments

On January 22, 1997, the Administrative law Judge's (ALJ) proposed decision was mailed to all parties for comments, pursuant to Rules 77.2-77.5 of the Commission's Rules of Practice and Procedure. On March 26, 1997, an alternate order of Commissioner Knight was mailed to all parties for comments as well. Based on our review of the comments filed by parties, we make revisions to our order for clarification as well as the following changes:

4 Parties agreed at hearing to enter by stipulation the testimony of Richard M. Hairston on behalf of WMA but due to inadvertent error, this did not occur. We will reopen the record in A.96-03-031 for the limited purpose of entering WMA's testimony as Exhibit 124.

1) Adopt SoCalGas' proposal to eliminate the G-SWAP storage schedule;

2) Clarify that the replacement cost adder is not an embedded cost methodology and that it is appropriate to include system replacement costs when measuring long run costs. However, the Global Settlement does not allow a methodology change of this magnitude and the Commission should consider LRMC changes in the context of a relook at its natural gas strategy;

3) Provide implementation language to our discussion on cogeneration parity for nonvolumetric contracts;

4) Adopt a settlement of SoCalGas and ORA for the treatment of Hub revenues;

5) Recalculate the tier rates within the G-10 and G-20 classes;

6) Modify our proposal to unbundle core interstate pipeline demand charges for SDG&E;

7) Recalculate SDG&E's core brokerage rate and adopt a noncore brokerage rate; and

8) Extend the time requirement for SDG&E to file a completed resource plan.

SoCalGas - A.96-03-031

II. Storage Program

A. Overview

SoCalGas proposes numerous revisions to the measurement and allocation of its existing system storage capacity. Its proposals come at a time when the demand for storage services has diminished on SoCalGas' system, primarily due to the increased availability of discounted pipeline capacity to transport additional flowing supplies in the winter. The record reflects SoCalGas has excess capacity in both its existing and expansion storage facilities. Our decision on storage capacity issues will determine the allocation of costs between customers and shareholders.

In D.93-02-013, the Commission unbundled noncore storage services for SoCalGas, SDG&E, and PG&E in order to meet the needs of noncore customers and to harmonize storage service with previously adopted policies and programs for unbundled gas supply and transportation service (48 CPUC2d 107). SoCalGas is obliged to continue to operate and expand storage on behalf of core customers and to provide firm service to noncore customers using existing facilities that are not needed for core service. (Id. at 115.) Core customers pay the full as-billed rate for existing capacity allocated to them. Noncore customers are able to obtain discounted contracts through an auction process, with 75% of the difference between full as-billed rate and the contract rate recovered from all customers on an equal cents per therm basis. Shareholders are assigned 25% of the revenue shortfall from discounted contracts. Unmarketed existing capacity is treated as a transition cost and amortized to all customers. For expansion capacity, shareholders assume 100% of the risk and are assigned all contract revenues.

Parties sponsoring testimony on storage issues are Alenco, ORA, Enron, Edison, SCUPP/IID, SDG&E and TURN. Alenco identifies itself as a potential competitor and states it seeks to have the Commission eliminate aspects of SoCalGas' policies and practices which tend to favor utility-provided storage.

ORA reviews the numerous changes proposed by SoCalGas with respect to its storage operations and presents testimony supporting some proposals and recommending existing policy be retained in other areas. Enron, a core aggregator, proposes storage costs be unbundled for core customers and opposes several of SoCalGas' proposals that Enron asserts shift costs to core customers.

Edison recommends that the Commission should direct SoCalGas to use existing storage withdrawal capacity before expansion capacity for all future storage contracts in order to ensure that customer costs are lowered to the maximum extent possible. Edison, SCUPP/IID, and SDG&E, all utility electric generation (UEG) customers, oppose SoCalGas' proposal to eliminate the G-SWAP tariff schedule.

<u>B. Inventory Capacity</u>

SoCalGas proposes to restate its inventory capacity from 115.3 billion cubic feet (Bcf) to 116.8 Bcf based on a new engineering analysis of its Honor Rancho storage field. SoCalGas testifies that (1) the increase in capacity is due to liquids production in the field over the past decade which is a normal by-product of natural gas storage operations and that results in an increase in effective working inventory capacity; and (2) SoCalGas did not have the operational data to measure and document the increased capacity at Honor Rancho until recently, which is why the modification is being proposed in this case. SoCalGas states core customers benefit from the increased capacity as SoCalGas is able to sell it and generate incremental revenues that reduce stranded storage costs. ORA accepts this modification.

Alenco opposes SoCalGas' recommendation, stating the increase capacity should be booked to expansion storage, not existing storage. Alenco states the record in this case is far from clear that the increase in capacity at Honor Rancho is the result of liquids production that occur as a result of normal gas storage operations, and even less clear that any capacity increase occurred prior to 1993.

Finally, Alenco states that SoCalGas' assertion that it could not restate the capacity of the Honor Rancho field until this BCAP because it lacked the appropriate operational data is belied by its own witness, who testified that he did not know when the analyses of the capacity of the Honor Rancho field occurred.

Enron also opposes SoCalGas' reclassification, stating SoCalGas improperly seeks to shift these storage costs to customers and reduce shareholder risk. SoCalGas has not justified that the additional inventory is warranted to serve core customer requirements or even that the additional capacity is useful. SoCalGas has also not identified the revenues obtained from production of liquids removed from the field.

1. <u>Discussion</u>

In D.93-02-013, we established the "cut-off point" for existing versus expansion capacity for SoCalGas' storage program and established different levels of customer and shareholder risk for unmarketed capacity under each category. SoCalGas has the burden of proof to establish that the additional capacity at Honor Rancho existed prior to its 1992 storage filing and that it could not be properly measured at that time.

While SoCalGas shows that the majority of liquids production at Honor Rancho occurred before February 1993, it does not establish that there is a direct correlation between liquid production and capacity expansion. Alenco's testimony supports the possibility that there may be slight or no linear correlation between liquids production in a given field, during a certain period of time, and the amount of inventory capacity in that field. (Transcript 1112-13, 1127.)

SoCalGas does not establish that all the liquid production in the field occurred as an unintentional byproduct of normal gas operations. The record shows that there are wells at Honor Rancho that are located outside the gas cap and used to produce oil independently of the storage operations. SoCalGas also relies on the same technology to intentionally create expansion capacity. Its Storage Resource plan includes a "more systematic liquids removal program to incrementally expand the working inventory" at Honor Rancho, and this program is designated as expansion capacity. (Exhibit 1, Chapter I, p. 30.)

Finally, while SoCalGas asserts it has only recently performed a full analysis of Honor Rancho's capacity, it does not demonstrate why it could not have performed this analysis prior to or during the 1992 storage proceeding.

Based on the above discussion, we find SoCalGas does not meet its burden of proof on this issue. Therefore, we do not adopt its proposal to restate its existing storage inventory capacity from 115.3 Bcf to 116.8 Bcf. The additional 1.5 Bcf of capacity at Honor Rancho should be considered part of SoCalGas' expansion capacity.

C. Firm Injection Capacity

SoCalGas proposes to revise its firm injection capability for cost allocation purposes from 803 MMcf/d as adopted in D.93-02-013 to 741 MMcf/d. SoCalGas states its change is based on a review of operational data which shows that customer overdeliveries may be as much as 1,000 MMcf/d on weekends, dropping to 300-400 MMcf/d on weekdays. Based on this analysis, it calculates an average available capacity of 741 MMcf/d over the 214-day injection cycle. SoCalGas states it cannot provide this level of capacity every day throughout the injection season but it is nevertheless an appropriate figure because 70% of the time customers do not request the maximum injection rate.

ORA opposes this proposal, stating SoCalGas relies on analysis which is based on a theoretical optimal distribution of storage inventory under an operating pattern of maximizing weekend injection capacity over part of the injection season. ORA states the more appropriate method for allocation purposes is to reflect the daily injection rates over the entire injection season. Its analysis supports retaining the existing 803 MMcf/d level.

Enron also objects to SoCalGas' proposal, stating that SoCalGas appears to identify its injection constraints as related to certain customers overdelivering on weekends and should address that problem directly; SoCalGas is under no obligation to provide firm storage injection to a customer in excess of 1,000 MMcf/d if that customer has elected firm injection rights of only 300 MMcf/d.

Enron also states that SoCalGas' statement that it cannot accommodate all customer requests for firm injection rates every day throughout the season raises questions as to the actual service that a customer receives when it requests firm injection service. Enron recommends SoCalGas be required to accurately describe the service it is able to provide and suggests that if, for operational reasons, SoCalGas must institute an injection schedule, it should tell customers what volumes can be injected at various times; such a schedule would be easier for a customer to accept than a situation in which on some days SoCalGas can accept the injection at the contract volumes and on other days it cannot.

Enron also objects to SoCalGas allocating the difference between its subscribed capacity and its total system capacity to load balancing, noting that this is merely an attempt by SoCalGas to recoup a potential stranded cost, since SoCalGas testifies there is only limited market interest in firm injection capacity, about 4 MMcf/d. (Exhibit 85, p. 18.)

TURN does not take a position on the system level, but notes in its testimony that SoCalGas' testimony establishes that its storage field is being routinely fully utilized and therefore, it makes no sense to classify any of its injection capacity as stranded. TURN recommends that any capacity left unsold, under either SoCalGas' or ORA's definition, should be treated as part of the load balancing allocation, and should not be allocated to available capacity where the demand appears highly uncertain. To the extent SoCalGas is successful in marketing some of this capacity, TURN recommends the revenues be tracked in an interest-bearing memorandum account and credited against allocated load balancing injection costs in the next BCAP.

TURN also points out that the full use of all available injection capacity, particularly on summer weekends, may mean that the core's reserved injection capacity is actually serving noncore customers and their suppliers whenever the core is not fully utilizing its reservation.

1. Discussion

SoCalGas' testimony raises significant questions about how it is administering its storage injection service. Rather than lowering the amount of firm injection capacity available, and thereby reducing the level of potentially stranded capacity and associated shareholder risk, SoCalGas should directly address the problem of large overdeliveries on summer weekends. It can do this by enforcing penalties for overdeliveries and also by marketing its available capacity to customers who consistently overdeliver.

Based on the record, we decline to adopt SoCalGas' proposal to revise its system injection capability. We retain the 803 MMcf/d of injection capacity. We will not adopt TURN's proposal to address this issue in a future BCAP. According to our Business Plan, we intend to issue a Natural Gas Strategy during 1997 and the result of that endeavor may change the nature of future cost allocation proceedings, or even recommend their discontinuation entirely. Given this uncertainty, it would be unwise to promise to address issues in a future BCAP. Instead, we direct the Executive Director to ensure that staff addressing the Natural Gas Strategy design a procedural roadmap following issuance of the Strategy to consider storage overdeliveries, a clear definition of firm service, and other storage issues in the appropriate forum.

D. Firm Withdrawal Capacity

SoCalGas proposes to reduce its adopted firm withdrawal capacity of 3,757 MMcf/d to 3,100 MMcf/d based on two adjustments: (1) a change from using a peak hour requirement on the peak day in January to using a 24-hour day basis, resulting in a 10% capacity reduction; and (2) restating the firm withdrawal capacity of the Playa del Rey storage facility from 450 MMcf/d to 100 MMcf/d to reflect the manner in which SoCalGas operates its system. SoCalGas states it has concluded that to optimize its overall system performance, it should delay using Playa del Rey until the latter part of the winter withdrawal season, thus limiting its available capacity.

ORA does not object to SoCalGas' request to change from a peak hour to a 24-hour basis. ORA does object to SoCalGas' request to change the rating of Playa del Rey.

ORA states that Playa del Rey withdrawal capacity remains as adopted in D.93-02-013. In the storage proceeding leading to D.93-02-013, SoCalGas revised the capacity rating upward from 350 MMcf/d to 450 MMcf/d to reflect a 100 MMcf/d increase in this field, the result of treating the wells with a chemical mixture.

1. Discussion

SoCalGas' proposal to change the peak hour requirement to a 24-hour requirement is reasonable. It testifies that traditional practice in the natural gas industry generally defines flowing supplies on a 24-hour basis and, therefore, firm withdrawal service should be also defined in this manner.

SoCalGas has not provided sufficient justification to reclassify the capacity of Playa del Rey. SoCalGas is not certain that it will use Playa del Rey only at the end of the season. It testified that it may also use Playa del Rey during the earlier part of the withdrawal season, although this is not routinely planned. SoCalGas can operate its system as it deems appropriate; however, the fact remains that Playa del Rey's capacity is 450 MMcf/d.

Therefore, we adopt a firm withdrawal capacity of 3,381 MMcf/d, a 10% reduction from the existing level of 3,757 MMcf/d.

B. Core Reservation Levels

In D.93-02-013 we unbundled the noncore storage and adopted reservation levels for the core. Unless a noncore customer subscribes to unbundled inventory, injection, or withdrawal services, it has, and pays for, no storage rights. In this proceeding, SoCalGas proposes to retain the adopted levels for the core's inventory reservation (70.0 Bcf) and its injection reservation (327 MMcf/d) but to change the core's withdrawal reservation.

SoCalGas requests we lower the retail core withdrawal reservation from 2,401 MMcf/d to 2,261 MMcf/d. It states its recommendation is based on (1) reflecting the effects of its recommendation to adopt a lower core reliability standard in its resource plan; and (2) a proposal to change the method of calculating core demand in order to address the reality of current flowing gas supply availability. In addition, SoCalGas has coupled its revised assumptions with the revised 24-hour definition for firm withdrawal service adopted in the previous section.

SoCalGas calculates its core storage demand based on an assumption that the total flowing supply available to the retail core on an extreme peak day will be 1,381 MMcf/d. SoCalGas witness Peter Yu testifies that the total flowing supply available on its system will be considerably higher than 1,381 MMcf but that the difference will be needed to meet wholesale core demand and certain level of noncore load that fails to comply with SoCalGas' curtailment order (Exhibit 3, p. 8.)

Yu testifies that SoCalGas' flowing supply estimate also reflects current market reality and the need for responsible planning. He states El Paso has historically diverted flowing supply during extremely cold weather to the east-of-California market and that recent efforts by El Paso and Transwestern to significantly increase their physical capacity to move San Juan Basin gas eastward will further reduce the amount of supply available to SoCalGas during extremely cold weather.

Yu testifies that he calculates a retail core peak hour requirement of 2,511 MMcf/d and then adjusts it downward by 250 MMcf/d on the assumption that firm withdrawal capacity allocated to noncore customers for load balancing service will be used to meet retail core peak day requirements. He recommends the change to a peak hour method in order to ensure that SoCalGas can meet all core demand during the early morning and evening hours.

SCUPP/IID generally supports SoCalGas' proposal but objects to SoCalGas' assumption that noncore load balancing capacity can be used to meet the core's extreme peak day requirements. SCUPP/IID witness Doering proposes language that would state noncore firm capacity may only be utilized on behalf of the core when necessitated by force majeure events that are outside of the reasonable control of core customers and the utility. (Exhibit 65, p. 15.) Edison supports this position.

Both ORA and TURN support SoCalGas' adjustment to reflect the revised peak day design criteria but oppose its request to change from a peak day to a peak hour criterion. ORA recommends a reservation level of 1,985 MMcf/d and TURN recommends a reservation level of 1,726 MMcf/d.

ORA states that SoCalGas' proposed change from peak day demand to peak hour demand results in an increase of 50% in the core's reservation, thereby almost completely nullifying the effect of the savings that come from lowering the core's reliability level from a 1-in-75 year probability of curtailment to a 1-in-35 year reliability level.

ORA objects to SoCalGas' proposal to change to a peak hour calculation on several grounds. First, SoCalGas does not provide adequate support for the high level of core demand that results from the peak hour adjustment. Given the excess capacity situation in California, the company has failed to demonstrate that reserving this much withdrawal capacity is the least expensive option from the core's perspective. SoCalGas should be directed to conduct a cost-effectiveness study of reserving varying amounts of withdrawal capacity versus other potentially less expensive alternatives such as procuring more gas supplies at market rates in addition to the core's interstate capacity rights.

Second, ORA states that basing the core's withdrawal reservation on extreme peak day, without the peak hour adjustment, is consistent with the methodology used by the company to determine the total system withdrawal capacity.

ORA retains the peak day methodology to arrive at its recommended reservation of 1,985 MMcf/d. It notes that this is a conservative figure as it uses SoCalGas' estimate for flowing supplies, a figure it believes may be understated given the current excess interstate capacity to California. ORA states further study should be done to determine the optimal amount for the core reservation.

TURN in the testimony of Michel Florio challenges SoCalGas' assumption that only 1,381 MMcf/d of flowing supply will be available to meet retail core demand on a peak day. Florio testifies that this estimate appears understated, is inconsistent with similar data elsewhere in SoCalGas' workpapers, and assumes zero diversion of noncore supplies to meet core peak needs, contrary to the Commission's policy as stated in D.91-11-025, the capacity brokering decision. Florio cites to a SoCalGas resource planning workpaper that he states shows expected peak day deliveries from various sources of supply at probability levels of 95% and above for 1995 on a 38-degree peak day to be 1,640.1 MMcf/d. (Exhibit 68, pp. 41-43.)

Florio also addresses SoCalGas' concern that supplies are being diverted to east-of-California markets in the winter season, stating that this was due to an extreme run-up in gas prices throughout much of the country as a result of extreme cold weather in the East and Midwest. It wasn't that gas was unavailable to California, rather that it was too expensive given our level of demand and the amount of available gas in storage. If it had been California that was experiencing record cold temperatures, Florio states that the gas would have flowed in this direction, albeit at a temporarily much higher price.

Further, Florio states SoCalGas' proposal does not address the provisions in the capacity brokering decision, D.91-11-025, for potential involuntary diversion of noncore supplies to meet just such contingencies, although not more than once in ten years for any single noncore customer on the SoCalGas system.

Based on the above, TURN recommends the Commission adopt a flowing supply assumption of 1,640 MMcf/d for purposes of developing a core withdrawal reservation. TURN agrees with ORA that the peak day methodology should be retained. Florio testifies that SoCalGas' peak hour adjustment is not necessary to cover peak usage periods:

> "SoCal's peak hour adjustment requires that an additional 1577 MMcf/d equivalent of demand be served over and above the peak day average demand. Mr. Yu's Table 3 (p. 18) shows that 1022 MMcf/d of that peak hour demand can be met by reducing line pack. The remaining 555 MMcf/d equivalent of peak hour demand can easily be met by storage withdrawal capability over and above the amount made available for

> sale to customers, which is based on sustained availability over a longer period of time. Attachment 8 shows that SoCal's total peak hour withdrawal capability is 4273 MMcf/d equivalent, far in excess of the 3100 MMcf/d that SoCal proposes to make available for sale and even the 3381 proposed by [ORA] based on different assumptions regarding Playa del Rey. Thus, the combination of linepack and excess withdrawal capability can easily cover the difference between peak day and peak hour demand." (Ex. 68, p. 47.)

Retaining the peak day demand measure in combination with its recommended flowing supply figure of 1,640 MMcf/d, TURN arrives at a recommended total core withdrawal reservation of 1,726 MMcf/d.

1. <u>Discussion</u>

TURN and ORA raise significant issues that warrant addressing. These issues are:

1. Given the excess capacity situation in California, SoCalGas fails to demonstrate that reserving its recommended level of withdrawal capacity is the least expensive option from the core's perspective;

2. Basing the core's withdrawal reservation on extreme peak day, without the peak hour adjustment, is consistent with the methodology used by the company to determine the total system withdrawal capacity;

3. As shown by TURN, excess withdrawal capacity in combination with line pack is more than adequate to make up the difference between peak day and peak hour demand;

4. Both TURN's and ORA's testimony indicate that, in calculating the reservation, the company has substantially understated the amount of flowing supplies available; and

5. TURN's testimony raises the issue that to assume there should be no diversion of noncore supplies is contrary to the provisions of D.91-11-025, the capacity

> brokering decision, which establishes procedures for voluntary and involuntary diversions of noncore supplies.

ORA notes that SoCalGas is proposing to reduce the reliability level to 1-in-35 years. With this change, it is reasonable to expect a reduction in the core withdrawal reservation. ORA's recommended withdrawal reservation relies on SoCalGas' assumption of 1381 MMcf/d of flowing supplies, but relies on peak day demand rather than peak hour.

We agree with ORA that that this is the appropriate estimate for the coming BCAP period of retail flowing supply availability. We also agree with ORA and TURN that the peak day method should not be changed to SoCalGas' proposal. TURN demonstrates that peak hour demand can be met through linepack and excess withdrawal capacity. (Exhibit 69, Attachment 8). Therefore, we adopt ORA's recommendation for a retail core firm withdrawal reservation of 1,985 MMcf/d.

We are also persuaded by ORA and TURN's recommendation that SoCalGas should provide a cost-effectiveness study of reserving varying amounts of withdrawal capacity versus other potentially less expensive alternatives such as procuring more gas supplies at market rates on peak days. We will direct our Executive Director to ensure that the appropriate division staff include these storage issues and concerns in their reexamination of a gas strategy for California, and develop a procedural roadmap for resolving these issues following issuance of the gas strategy. In that roadmap, staff may either recommend a future BCAP or another proceeding as the proper forum for addressing these issues. This is consistent with the standard we adopted for core storage reservations in D.93-02-013:

> "Utilities should reserve storage quantities - of injection, inventory, and withdrawal - for core customers that provide, on a forecast basis, certainty of gas supply to meet winter peak requirements at the lowest possible

> overall cost. This is consistent with the core service policies announced in D.89-04-080. Core reservations should include reliability and price function quantities." (48 CPUC2d 113, 123.)

TURN addresses SCUPP/IID's concern with the core's occasional use of noncore capacity by stating that all parties agreed to this provision in the capacity brokering proceeding; SCUPP/IID's and Edison's recommendations are contrary to the representations made to the Commission by the utilities and other parties, as well as the language adopted by the Commission in D.91-11-025 on the provisions for voluntary and involuntary noncore diversions. (See Exhibit 68, pp. 43-45 and 41 CPUC2d 668, 681.) We agree with TURN and also find that the Commission directly addressed this issue in its storage decision, D.93-02-013:

> "Utilities must curtail noncore service to serve core reliability needs. We recognize that this possibility compromises the firmness of noncore service, but the likelihood of such curtailments is small. In such situations, utilities should withdraw noncore gas from storage or divert noncore flowing supplies in a manner that is fair and economic to noncore customers." (48 CPUC2d 113, 120.)

SCUPP/IID's and Edison's request is contrary to clearly stated Commission policy and we do not adopt this recommendation.

Finally, we note that Edison, ORA, TURN, and Alenco raise concerns with the manner in which SoCalGas is assigning storage revenues for withdrawal service between existing and expansion facilities. We will address this issue below under "Allocation of Storage Contract Revenue."

F. <u>Load Balancing Reservation</u>

Pursuant to D.93-02-013, SoCalGas provides a bundled load balancing service for all customers. This service consists of providing hourly, daily, and monthly balancing of gas supply deliveries and actual burns at customer premises. It is termed

"10% monthly balancing service" because there are penalties to customers who fail to balance deliveries and consumption beyond a 10% tolerance band, calculated on a cumulative monthly total. In this proceeding, SoCalGas proposes to change the reservation levels for load balancing and also the cost allocation methodology. This section will address the reservation level. We address the cost allocation methodology in the LRMC methodology section.

SoCalGas proposes to change its load balancing reservation levels for injection and withdrawal and to retain its existing inventory level based on a load balancing study it presents. SoCalGas proposes to increase the amount of the injection reservation from 297 MMcf/d to 355 MMcf/d because customers systematically fully utilize the injection capacity to balance their supplies and burns. SoCalGas proposes to lower the withdrawal reservation from 450 MMcf/d to 250 MMcf/d based on 15% of the retail noncore demand on a 42-degree day in January, stating this is a reasonable estimate of the amount of customer under-deliveries when SoCalGas imposes the 10% daily balancing conditions or the curtailment of standby service.

ORA does not oppose these changes, although it notes that SoCalGas experienced mild winters during the time frame of its study (November 1, 1993 - November 30, 1995) and was therefore not able to estimate the necessary withdrawal reservation on a cold day based on the data collected.

TURN recommends all firm injection capacity in excess of the 371 MMcf/d already reserved for the core or under noncore contract be allocated to the load balancing reservation, as SoCalGas' testimony establishes this capacity is routinely used on summer weekends to cover large overdeliveries. TURN states the demand for additional contracts appears highly uncertain but if SoCalGas is able to market some of the capacity on a firm basis, it should be allowed to do so and credit the resulting revenues back against load balancing injection costs in the next BCAP.

Enron objects to SoCalGas increasing its injection reservation, stating this is merely an attempt by SoCalGas to recoup a potential stranded cost. Enron states SoCalGas arrived at its 355 MMcf/d recommendation not based on a study identifying cost causation but instead by simply subtracting the 371 MMcf/d of core and subscribed capacity and an estimated 15 MMcf/d of incremental sales from its recommended total system capacity of 741 MMcf/d.

1. Discussion

SoCalGas' recommended load balancing inventory level (5.3 Bcf) and withdrawal level (250 MMcf/d) is reasonable and should be adopted. Its injection level is more problematic.

SoCalGas is routinely fully utilizing its capacity to provide load balancing to noncore customers on summer weekends, but we have already directed SoCalGas to take steps to remedy the large summer weekend imbalances. Therefore, we do not find a reservation level of 476 MMcf/d, the result of TURN's recommendation, to be an appropriate level.

We also agree with Enron that SoCalGas' proposal appears to be a derivative number. However, we do not agree with Enron that the level should remain at 297 MMcf/d. The record indicates the appropriate level lies somewhere between TURN's and Enron's proposals. We have directed our Executive Director to ensure staff address this issue in any roadmap emanating from our upcoming Natural Gas Strategy. We also address in the Storage Services section changes to SoCalGas' imbalance trading procedures that may help to reduce the level of summer weekend imbalances.

Based on the record, we should adopt the 355 MMcf/d injection level supported by SoCalGas and ORA and revisit the issue of injection capacity as designated by the future procedural roadmap we expect to issue following our forthcoming Natural Gas Strategy.

Following is a table summarizing the storage capacity and reservation levels we have adopted for the coming BCAP period. For comparison purposes, a table of currently adopted levels is provided.

Storage Comparison Table
(Currently Adopted Storage Capacity

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)
Total System	115.3	803	3,757
Core	70.0	327	2,401
Balancing	5.3	297	450
Unbundled Storage Program	40.0	179	906
Sold	43.8	45	367*
Available Capacity	(3.8)	134	539

Proposed Storage Capacity

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)
Total System	115.3	803	3,381
Core	70.0	327	1,985
Balancing	5.3	355	250
Unbundled Storage Program	40.0	121	1,146
Sold	20.4	44	367
Available Capacity	19.6	77	779

* Adjusted to reflect expiration of 225 MMcf/d Edison contract 3/31/96.

G. Other Storage Service Issues

1. Contract Revenues

ORA, TURN, SCUPP/IID, Edison, and Alenco request the Commission clarify the revenue and cost allocation treatment that SoCalGas should follow in marketing its storage capacity. In D.92-02-013, we unbundled storage service from transportation service and adopted a "let the market decide" policy for storage expansions, requiring utility management to determine when such expansions were required and utility shareholders to be at risk for revenue recovery. We stated that "We expect no facility expansions until existing unsubscribed capacity is used."[5] We gave the utilities the discretion to implement our intention by stating the following:

> "The utilities should develop practical, fair methods for assignment of storage customers to existing or new facilities to ensure that the various revenue protections--for unsubscribed capacity, bypass shortfalls, bypass discounts, customer reliability, and load balancing requirements--can be correctly implemented. (Id. at 131.)

SoCalGas has filed several advice letters recently requesting Commission approval of storage withdrawal contracts and on a case-by-case basis has designated these contracts as existing or expansion storage. ORA, TURN, SCUPP/IID, and Edison state that SoCalGas should use capacity from existing facilities before using expansion facilities to provide firm withdrawal service under new contracts. As we have identified 1,038 MMcf/d of available existing withdrawal capacity in the previous section, we find implementation of this proposal necessary in order to protect ratepayers from unnecessary stranded cost charges.

TURN's witness Florio identifies the fact that SoCalGas has "sold" more expansion withdrawal capacity than it has constructed, and intends to keep the excess revenue (about $900,000 per year), even as its ratepayers are forced to pay for stranded existing facilities. TURN recommends the company be directed to credit any revenues from storage contracts in excess of the capacity of expansion facilities back to the Storage Transition Cost account. (Exhibit 68, p. 51.)

5 D.93-02-013, 48 CPUC2d at 120.

The issue raised by TURN warrants requiring SoCalGas take remedial action. Therefore, we direct SoCalGas to file an advice letter within 10 days (1) reconciling by month, beginning with January 1, 1995, its expansion contracts to the operating capacity at its expansion facilities and (2) crediting back any revenues from storage contracts in excess of its expansion capacity to the Storage Transition Cost account.

ORA's witness Tan identifies another problem, one involving an off-system storage contract. Tan testifies that SoCalGas recently negotiated an off-system storage contract with British Columbia Gas for inventory, withdrawal, and injection service. SoCalGas states in its advice letter that it will need to expand its storage withdrawal facilities in order to meet this contract obligation. ORA, however, states that contract can be met with excess existing capacity and recommends that any revenue generated from this contract be directly credited to the Storage Transition Subaccount, thereby offsetting any transition costs currently borne by SoCalGas' customers.

While withdrawal capacity is the area of immediate concern, Alenco, TURN, and SCUPP/IID also address all storage expansion facilities planned by SoCalGas. They recommend the Commission clarify its policy on marketing storage capacity to require that for purposes of cost allocation, SoCalGas treat all marketed capacity as existing capacity as long as any existing capacity remains unmarketed. Based on the record in this proceeding, we adopt this requirement, namely that SoCalGas for cost allocation purposes treat all marketed capacity as existing capacity as long as any existing capacity remains unmarketed. This requirement applies to all storage contracts, including off-system storage contracts.

2. Imbalance Trading Procedures

SoCalGas proposes certain modifications to its imbalance rules. These rules govern the "10% monthly load balancing service" discussed previously in the Load Balancing Reservation section. SoCalGas states that when the Commission first adopted the imbalance trading procedures in D.90-09-089, it was necessary to build in a time lag due to concerns about SoCalGas' operational limitations in collecting and processing imbalance data on a timely basis. The current rules, therefore, provide a noncore customer the opportunity to trade with customers with offsetting positions two months following the occurrence of the actual imbalance.

SoCalGas states that now that it and its customers have had experience with the imbalance trading process, it is time to tighten the rules to allow it to more efficiently manage the imbalances. SoCalGas proposes to modify the procedure as follows:

1. Customers will have until the end of the following month to finalize imbalance trading transactions for prior month imbalances;

2. A storage customer may trade positive imbalances, i.e., overdeliveries, into its storage account only if its storage inventory capacity is available during the month that the imbalance occurred and at the time the imbalance trading takes place; and

3. A storage customer may trade negative imbalances, i.e., underdeliveries, using its storage account only if there is sufficient gas in storage in the account during the month that the imbalance occurred and at the time the imbalance trading takes place.

ORA supports SoCalGas' proposal, stating that the modifications are consistent with the intent expressed by the Commission in D.90-09-089.

SCUPP/IID objects to SoCalGas' proposal, stating that SoCalGas' proposal appears designed to force customers to purchase storage capacity in order to "cure" imbalances.

a. Discussion

SoCalGas' proposal is a timely one, as the record in this proceeding identifies parties' concerns with the large imbalances that SoCalGas reports. D.90-09-089 sets forth the purpose of the load balancing service and our concern with imbalances:

> "We agree with PG&E and (ORA) that the balancing provisions of the Settlement and the proposed rules are unlikely to encourage customers to plan their gas takes carefully, and the utilities and their ratepayers should not be responsible for the costs associated with imbalances...
>
> "Our adopted rules for balancing and storage will recognize that balancing services should not replace storage. They will recognize the costs of using utility resources and also promote well-planned nominations by customers....As we said in D.90-07-065, we believe trading between customers to equalize imbalances is reasonable if it would not complicate utility operations." (37 CPUC2d 583, 623.)

SoCalGas' proposed modifications to the imbalance trading procedures should improve SoCalGas' load balancing service; therefore, we adopt the proposal.

3. Enron's Proposal to Unbundle Core Storage Services

Enron proposes that the Commission unbundle storage facilities from core transport rates in this proceeding. It states the need for storage has diminished on SoCalGas' system and core customers should have the same opportunities as noncore customers in choosing the storage services they need.

It cites the testimony of SoCalGas that there is little market interest by retail noncore customers in purchasing firm storage rights and, to the extent services are purchased, they are at prices well below the full as-billed rate.

Enron states it knows there may be a stranded cost issue associated with core storage unbundling but that this issue alone should not justify continued bundling of unwanted or unneeded services. Enron suggests that a balancing account, similar to the noncore storage balancing account, be used to recover shortfalls.

We believe we should implement the unbundling of core interstate capacity reservations before we proceed to address unbundling core storage costs. As Enron readily concedes, there will be stranded costs and a transition period needed to recover these amounts. Therefore, we do not adopt this proposal in this BCAP.

4. SoCalGas' Proposal to Eliminate G-SWAP Schedule

SoCalGas proposes to eliminate its G-SWAP storage service. This service was authorized in D.93-02-013 as an unbundled, firm, counter-cyclical storage service to retail noncore customers and wholesale customers in an effort to improve air quality in southern California. SoCalGas states that with the addition of new interstate pipeline capacity to southern California this tariff is no longer needed for air quality purposes as noncore customers have other options to meet their summer peak energy requirements. Further, the counter-cyclical economic and operational rationale for offering this service with no storage reservation charge is no longer valid.

SoCalGas testifies that noncore customers interested in obtaining storage services similar to the G-SWAP program can negotiate with SoCalGas to purchase the needed services under its G-TBS tariff schedule; all ratepayers will benefit from its proposal as reservation revenues generated under the G-TBS program will be used to reduce stranded storage costs.

SCUPP/IID and Edison oppose SoCalGas' proposal. Both testify that SoCalGas' system remains counter-cyclical, therefore their injection of gas in the winter months and withdrawal of gas in the summer months has economic and operational value on

SoCalGas' system. Without the G-SWAP tariff available, SCUPP/IID and Edison expect to pay more for counter-cyclical storage services from SoCalGas.

We find that SoCalGas has presented sufficient justification to eliminate the G-SWAP service and we adopt its proposal.

III. Long-Run Marginal Cost (LRMC) Methodology

A. Resource Plan

In D.92-12-058, the Commission directed that resource plans be filed in general rate cases rather than BCAPs in order to allow parties sufficient time to examine the complex issues (47 CPUC2d at 439, 474). In D.94-07-024, we granted PG&E's request for a one-time exception to file its resource plan in its 1994 BCAP due to (1) consistency with the schedule set in D.94-05-069, which found PG&E's resource plan for unbundled gas storage services to be inadequate and directed a new filing in its next BCAP; and (2) an opportunity to reflect the effect of an updated resource plan in rates two years earlier than presently scheduled. In granting PG&E's request, we found that additional time would be needed within the BCAP schedule if resource planning was added to the scope of the proceeding and, therefore, scheduled an additional three months for the Commission and interested parties to review the utility's filing. We also stated:

> "PG&E's request is only for its upcoming 1994 BCAP; this decision does not change the forum for SoCalGas or SDG&E, nor for PG&E's subsequent proceedings." (D.94-07-024, 55 CPUC2d 338, 341.)

Both SoCalGas and SDG&E include resource plans in their applications without having requested, or been granted, Commission authority to deviate from the filing requirements of D.92-12-058. In its application, SDG&E incorrectly states the Commission granted it authority in D.94-05-069 to file a resource plan in this BCAP. (Exhibit 201, XI-1.) We do not agree. The referenced portion of D.94-05-069 applies only to PG&E, as discussed above.

SoCalGas testifies at hearing that it includes the resource plan for two reasons: (1) its general rate case would have been for 1997 but is delayed or postponed due to its performance-based ratemaking (PBR) application; and (2) it considers the BCAP the logical and traditional place to update. (Collette, Transcript 997.)

No party protests the inclusion of the resource plans in this BCAP, but the hearing record demonstrates that while it is logical to review a resource plan in the BCAP, as it is the basis for measuring transmission, storage, and distribution marginal capital costs, the Commission and interested parties clearly need more time and resources to thoroughly review the utilities' resource plans than the normal BCAP schedule allows.[6]

In D.92-12-058, we specified that resource plans for the gas utilities should: (1) include at least a 15-year planning horizon for backbone transmission and storage and at least a 10-year planning horizon for local transmission; (2) contain explicit system design reliability objectives for both core and noncore customers; and (3) reflect an appropriately planned system that meets customers' needs at the lowest total cost. (47 CPUC2d 438, 451.)

SoCalGas submitted its resource plan for transmission, storage, and distribution investments based on the demand forecasts contained in the 1995 California Gas Report and using the marginal

6 SoCalGas' proposed a longer schedule at the April 26, 1996 prehearing conference. Its proposed schedule, however, would have given ORA only an additional one and a half weeks to prepare its testimony, thereby still not providing the additional time for review provided in the PG&E BCAP schedule.

demand measures adopted for these functions in D.92-12-058 and D.93-05-066. As part of its Transmission Resource Plan, SoCalGas submits a Core Peak Day Reliability Study. Based on the results of this study, SoCalGas proposes to change the calculation of its Extreme Peak Day (EPD) design criteria from a 1-in-75 year event to a 1-in-35 year event.

1. Capital Investments Proposed By SoCalGas

SoCalGas' resource plan contains capital investments totaling $88.52 million for its transmission system and $68.6 million for its storage system. Its investment plan is:

Transmission Resource Plan

Project	Incremental Capacity (MMcf/d)	Cost ($ million)
Adelanto Rewheel	n/a	0.98
Adelanto Expansion	300	28.00
Line 6900 Phase 4	60	13.15
Line 6900 Phase 3	90	11.77
Line 6900 Phase 2	110	6.99
Imperial Valley Pipeline, Line 6902 Extension	80	12.30
Line 115/765 Uprating	n/a	2.11
East/Chino Capacity	150	$13.23
Total Transmission Capital Costs		$88.53

Storage Resource Plan

Project	Incremental Capacity (MMcf/d)	Cost ($ million)
Aliso Canyon Withdrawal Expansion	450	41.45
Honor Rancho Withdrawal Expansion	200	16.40
Goleta Inventory Expansion	3,800	6.30
Honor Rancho Inventory Expansion	2,796	4.45
Total Storage Capital Costs		$68.60

ORA does not take issue with SoCalGas' estimate of $88.52 million for specific projects in its transmission resource plan. ORA does differ with SoCalGas on its storage investments, recommending $38.13 million less in capital projects and the removal of $790,000 of forecasted incremental annual operation and maintenance costs. Both of these adjustments relate to ORA's recommendation to remove the 450 MMcf/d Aliso Canyon Withdrawal Expansion project from the resource plan. ORA forecasts that SoCalGas' retail core withdrawal reservation requirements are lower than what SoCalGas estimates; therefore, it believes that the Aliso Canyon Withdrawal Expansion Project is unnecessary at this time and will likely be deferred beyond the current 15-year planning horizon.

ORA notes in its testimony that SoCalGas includes investments in its resource plan that are not growth related. It specifically cites the Adelanto Rewheel and Line 115/765 Uprating projects, stating these investments are included by SoCalGas to provide the system more operational flexibility and to allow its customers increased access to alternative gas commodity markets.

While ORA does not object to inclusion of these investments, it states SoCalGas' inclusion of nondemand-related investments raises questions regarding the appropriateness of using only peak demand criteria to allocate marginal transmission costs to customer classes.

In its testimony, ORA discusses the significant changes that have occurred in SoCalGas' long-term forecast and, correspondingly, its proposed resource plan since its last BCAP proceeding in 1994. In its last BCAP, SoCalGas used the 1993 California Gas Report (CGR) and in this proceeding it relies on the 1995 CGR.[7] ORA states that SoCalGas' primary design criterion to evaluate its transmission system involves assessing system capabilities under cold weather conditions. In the two-year period between the 1993 and 1995 CGR, the projected growth in cold year demand through the year 2010 has dropped 40%, from 345 Bcf to 210 Bcf.

This large change in projected demand has an even more significant effect on SoCalGas' resource plan. In its 1993 BCAP, SoCalGas' transmission resource plan included a 1,447 MMcf/d increase in capacity costing $157.0 million in capital investments. In this BCAP, SoCalGas' resource plan includes a 790 MMcf/d increase in capacity costing $88.52 million. SoCalGas states that since the 1993 resource plan $55.9 million of projects have been cancelled or extended beyond the 15-year planning horizon for the 1996 BCAP.

While ORA recognizes the importance of the long-term demand forecast in setting LRMC-based prices, it testified it did not take issue with the forecast because it lacks the staffing resources to adequately review the CGR in the time alloted to process a BCAP application. A thorough review of LRMC resource

7 SoCalGas employees prepare the forecast published in the CGR.

plans is extremely difficult; ORA testimony of both its resource planning witness and its marginal cost witness state that staff did not have sufficient time to go into the detail of the resource plan.

Both Long Beach and SCUPP/IID question $72 million of the $88.5 million included in SoCalGas' resource plan. They state the Adelanto expansion is an unneeded investment in facilities designed to enhance SoCalGas' ability to receive Rocky Mountain and Canadian gas supplies, Line 6902 is being built to serve Mexico not incremental demand in the Imperial Valley, and Line 6900 is an expansion to serve SDG&E and Mexican markets.

These parties also challenge SoCalGas' long-term demand forecast, noting there is (1) no reflection of pending Mexican projects; (2) no change in the forecast of future UEG demand despite SoCalGas' testimony that it expects electric restructuring in this BCAP period to produce major changes in UEG load; and (3) SoCalGas' demand projection for the area served by IID is significantly higher than IID's own forecast. SCUPP/IID's witness John Burkholder testifies that resource plans are too difficult to analyze within the time frame of a BCAP proceeding and are an area that is "a potential hotbed of cost shifting and abuse" (Exhibit 89, p. 4). Burkholder recommends the Commission return to the practice of reviewing resource plans in general rate cases (GRCs).

Long Beach, as a wholesale customer, objects to its rate being set by LRMC methodology and points out the deficiencies it sees in SoCalGas' resource plan and the marginal transmission costs that result from it to support its argument that the Commission should return to embedded-cost ratemaking. While it doesn't sponsor an embedded-cost proposal, Long Beach does request it be excluded from the scaler mechanism used to reconcile marginal cost revenues to the embedded revenue requirement.

SCUPP/IID sponsors a rate proposal reflecting its recommendations. It removes the Adelanto expansion and Lines 6900 and 6902 from SoCalGas's transmission resource plan, treats Phase 4 of Line 6900 as an exclusive use facility for SDG&E, and recommends Phases 2 and 3 of Line 6900 be included in SDG&E's resource plan with an adjustment for the marginal cost revenues from these phases made to SoCalGas' marginal cost calculations.

SCUPP/IID in its reply brief cites an ORA audit report served September 27, 1996 in SoCalGas' Performance-Based Ratemaking proceeding, A.95-06-002. This report cites a SoCalGas data response that Line 6900, in its entirety, is being installed to support the customers within SDG&E's territory, and that SoCalGas and SDG&E have entered into a confidential agreement concerning the ratemaking positions they will advocate for Line 6900 cost allocations. (Reply Brief, p. 27.) SCUPP/IID states that if the proposed merger of SoCalGas and SDG&E (Pacific Enterprises/Enova) announced October 14, 1996 is approved, the surviving parent corporation of SoCalGas will benefit directly by shifting the costs of Line 6900 from SDG&E to SoCalGas' customers. In addition, SCUPP/IID states:

> "according to the Los Angeles Times, two of the projects to be undertaken by this new utility giant are a $600 million power plant in Rosarita, Baja California, as well as a new natural gas distribution system in Baja. The proposed expansion of Line 6900 will terminate right across the border from Baja California. Thus, it appears that the true basis for expanding Line 6900 is not to serve SoCalGas customers south of Moreno, but to provide service to Mexico. Until all of these issues are thoroughly investigated, the Commission should reject SoCalGas' proposal to include the expansion of Line 6900 in the current Transmission resource plan." (Id. p. 29.)

SCUPP/IID also offers new arguments regarding Line 6902 in its reply brief:

> "On August 13, 1996 it was announced that a consortium consisting of SoCalGas, SDG&E and the Mexicali firm, Proxima, won an exclusive concession to sell natural gas directly to

> consumers in Mexicali, Mexico. Mexicali is directly across the border from the point where SoCalGas proposes to expand Line 6902, at the end of the Imperial Valley Pipeline...SoCalGas' failure to address this issue is particularly suspect in light of the proposed merger between Pacific Enterprises and Enova. Just as with Line 6900, the surviving parent of SoCalGas stands to benefit directly if SoCalGas can convince the Commission to shift the costs of Line 6902 to the SoCalGas ratepayers." (Id. p. 30.)

<u>Discussion</u>

The concerns raised regarding SoCalGas' long-term demand forecast and its transmission resource plan are serious and beyond the scope of this proceeding to fully resolve. On the other hand, we find it troubling that we are called upon to scrutinize the resource planning process of this industry. This level of scrutiny appears to be a vestige of our former "command and control" regulation of the gas industry and is incompatible with our shift towards performance-based regulation. Nevertheless, our objective in adopting the resource planning process as the foundation of LRMC methodology was that "resource planning defines and justifies the facilities that a utility will build to meet customer service requirements" (47 CPUC2d 438, 449). Given the showing in this proceeding, we are concerned that:

> Long Beach and SCUPP/IID have raised issues regarding $72 million of SoCalGas' $88.5 million transmission resource plan that have not been adequately addressed by SoCalGas.
>
> The record in this proceeding does not allow us to rely on SoCalGas' long-term demand forecast. ORA testifies it did not thoroughly review the forecast and Long Beach and SCUPP/IID raise questions regarding the forecast that must be further investigated. The record shows that SoCalGas' forecast of long-term growth in cold year demand has dropped a remarkable 40% in the last two years.

> SoCalGas does not demonstrate that the 15-year time horizon of its resource plan is an adequate measurement of long-term investments. ORA testifies that SoCalGas' 1993 resource plan included $55.9 million of projects which have since been cancelled or extended beyond the 15-year planning horizon for this BCAP. In addition, ORA states that about $9.4 million of capital investments appear to be unaccounted for in this proceeding compared to the 1993 BCAP. (Exhibit 58, 6-8.)

SoCalGas has not met its burden of proof to show the reasonableness of the manner in which it proposes to include the expansions of Line 6900 and 6902 in its transmission resource plan. The specific ratemaking treatment to be given Line 6900 and Line 6902 should be further investigated and fully resolved prior to final Commission action on the proposed Pacific Enterprises/Enova merger. SoCalGas' PBR proceeding and the merger proceeding are appropriate forums for this review.

Our concern regarding the accuracy of SoCalGas' long-term demand forecast is an issue we identified in our initial adoption of LRMC methodology. In D.92-12-058, we discussed ORA's concern that PG&E's long-term forecast of industrial demand had increased by over 100% in just four years, the same period in which it proposed to increase its rate base by $2 billion through construction of the PG&E/PGT expansion pipeline. We stated:

> "Our guidelines called for the use of the 1991 California Gas Report in this proceeding. 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." (47 CPUC2d at 450.)

In adopting a long-run rather than short-run pricing methodology, we expected LRMC methodology to provide a measure of pricing stability and predictability for customers. We recognized in 1992 that in our interest to expeditiously implement marginal cost pricing we accepted some simplifications in setting the cost methodology and that these areas would require further review in later proceedings. We have only had the opportunity to closely review resource planning in two proceedings: this BCAP and in PG&E's last BCAP, D.95-12-053. In both cases, we find application of LRMC methodology leads to more questions than answers. We agree with ORA's assessment:

> "As a result of its participation in various proceedings, ORA has concluded that the implementation of a LRMC methodology which is consistent with the Commission's goals remains a challenge. In concept, as described in textbook form, marginal cost sounds simple. Yet, in actual implementation and practice, marginal cost can be controversial and result in distorted price signals." (Exhibit 58, 11-13.)

The specific problems with our adopted LRMC methodology that ORA identifies as needing further investigation will require a commitment of considerable Commission resources and a proceeding schedule simi)ar to a GRC, not a BCAP. These problems are:

> "(1) Forward-Looking Incremental Cost Approach
>
> "A forward-looking approach has a great deal of uncertainty associated with the data used to develop LRMC. For example, resource plans change significantly from one case to the other. (See SoCalGas resource plans from its last BCAP and this BCAP).) These resource plans are based upon long-term demand forecasts that do not receive adequate review in the time alloted to process an application. In large part, ORA simply lacks the staffing resources to duplicate these forecasts. It also imposes significant monitoring requirement on the Commission.
>
> "(2) Resource Plan
>
> "A least-cost resource plan, upon which marginal costs are based, becomes less meaningful or confusing when the system is

mixed with competition and regulation. For example, a least-cost transmission and storage resource plan may in fact become much more costly to the core. (See Appendix B of this chapter.)

"(3) <u>Design Criteria</u>

"A design criteria with a low probability of occurrence results in large cost consequences to the core. For instance, the storage withdrawal capacity determined is based on the core's extreme peak day temperature may be used to satisfy both the core and the noncore's total demand under a less extreme temperature condition. In other words, a storage withdrawal capacity reservation for the core assuming 38-degree day is sufficiently large enough to meet all the core and noncore needs under a 42-degree day. However, the 42-degree day is a more likely scenario than the 38-degree day yet it is the extreme day that is used to allocate costs.

"(4) <u>Scaling of Marginal Cost Revenues</u>

"The utility's marginal cost revenues are scaled up to meet its embedded cost revenue requirement. There are two problems associated with scaling. First, the marginal cost signal is lost in the process. Second, it is not clear why the marginal cost revenue should be proportionally scaled up to meet the embedded revenue. Instead, the difference between the embedded revenue and the marginal cost revenue probably should be considered as stranded investment that is not recoverable based on forward-looking marginal cost pricing." (Ex. 58, 11-14.)

While we acknowledge that the problems identified by ORA need to be addressed in a timely manner and that the resource plan filed by SoCalGas in this proceeding needs further investigation, we also recognize that under the terms of the Global Settlement, we will be using LRMC methodology for SoCalGas through 1999. The time for a thorough analysis, therefore, is prior to the expiration of the Global Settlement. We direct the Executive Director to ensure staff include this issue in the procedural roadmap which will follow the issuance of our Natural Gas Strategy for California.

For purposes of this proceeding, we have two options: (1) set a new procedural schedule to further investigate SoCalGas' resource plan and, in the interim, retain the existing adopted plan from the 1993 BCAP; or (2) use SoCalGas' filed resource plan for purposes of calculating LRMC methodology unless, and until, the Commission's later review of Lines 6900 and 6902 leads us to order a new resource plan filing. Option 2 is preferable to option 1 because it avoids an additional proceeding unless, and until, we find it necessary. Therefore, we adopt for this BCAP a transmission resource plan of $88.53 million and a storage resource plan of $68.60 million.

2. Replacement Cost Adder

ORA recommends that the resource plans used to set LRMC reflect not just incremental investments needed to meet new load growth, but all capital investments that will be necessary to maintain the adopted level of reliability for customers. Therefore, ORA proposes to reflect the replacement costs of necessary capital facilities in the calculation of marginal transmission, distribution, and storage costs; it states a replacement component is already reflected in marginal customer costs. ORA's proposal, termed a "replacement cost adder" was adopted for PG&E in D.95-12-053.

SoCalGas strongly opposes the use of a replacement cost adder. It states only incremental costs directly related to serving new demand should be reflected in marginal costs. The Commission should not adopt the replacement cost adder for SoCalGas because: (1) the Commission's definition of marginal cost is not broad enough to include the replacement cost adder; (2) the inclusion of replacement costs in the marginal cost calculation does not meet the Commission's stated policy objectives for adopting LRMC-based prices; (3) the concept of including replacement costs in a marginal cost calculation is foreign to any commonly accepted approach to the calculation of marginal costs; and (4) the reasons ORA recommended a replacement cost adder for PG&E do not apply to SoCalGas.

In addition, SoCalGas states that application of the replacement cost adder in this proceeding would violate the terms of its Global Settlement. SoCalGas testifies that in the Global Settlement all parties agreed to continue to use LRMC cost allocation methodology during the five-year term of the settlement. SoCalGas states that the LRMC-implementation decision shifted approximately $124 million in costs from the noncore to the core and adoption of this proposal would reverse that trend and signal a return to embedded cost ratemaking. Specifically, SoCalGas states adoption of the replacement cost adder violates the following provision of the Global Settlement:

> This provision was intended to be general enough to allow for refinement of the methodology in ways which contribute to its accuracy, internal consistency and completeness in estimating marginal costs. Changes intended to shift allocation towards other goals (such as value of service pricing, embedded costs, or Ramsey pricing) would be inconsistent with this provision. (Exhibit 71, Implementation Appendix Section C-5, p. 24.)

SoCalGas' position is supported by CIG/CMA, SCUPP/IID, SDG&E, and Edison. CIG/CMA's witness Dr. Barkovich defines marginal cost as "a measure of the change in total cost relative to a change in output" and states fixed costs that change due to factors other than output or load, such as replacement of facilities in order to maintain the utility's system operations, are not marginal costs (Exhibit 83, pp. 3-6). CIG/CMA supports SoCalGas' definition of marginal costs:

> Marginal cost is defined as the change in total cost that results from a small change in output. It is defined in terms of the unit change in cost that results from a unit change in output. Reliability refers to the reliability of the output. Changes in reliability can affect marginal costs either by changing the amount of output that is being analyzed for purposes of calculating the marginal cost, or by affecting the cost required to serve the additional output. (Exhibit 72.)

TURN proposes a replacement cost adder that is similar to ORA's but calculated using an average over several years of projected investments rather than ORA's depreciation proxy. Specifically, TURN uses 1991-94 for distribution, 1994-2000 for transmission, and 1996-2000 for storage.

TURN states the definition of marginal cost as the change in cost resulting from a change in output requires replacement costs to be included in order to prevent a negative change in output from occurring; without new investment to keep the existing system operable, SoCalGas could not maintain reliable service to its existing load. TURN notes that its methodology is consistent with SoCalGas' proposal to include all operation and maintenance (O&M) costs in its marginal costs in this case and in its last BCAP. PG&E, in contrast, only included as a marginal cost O&M costs associated with new investments that provide load growth in its last BCAP application.

<u>Discussion</u>

We have two issues before us in considering ORA's and TURN's proposals for a replacement cost adder: (1) does it meet the definition of a marginal cost; and (2) does adoption of it in this proceeding violate the terms of the Global Settlement?

Turning to the issue of the definition of marginal costs, we find that including the future replacement costs is not an embedded costing methodology. In the long run, new capital additions are planned to serve the projected system load in an efficient manner, not to simply duplicate the existing system. It is a well accepted principle of economics that the "long run" is defined as a period of time in which all inputs to a firm are considered variable for decision making purposes.[8]

In other words, in the true definition of long run, all costs are variable and there is an opportunity cost to not replacing the existing system. If replacement costs are not incurred, additional capacity costs will be required to maintain efficiency. As CIG/CMA point out in comments on the proposed alternate order, the Commission's adopted LRMC methodology already incorporates a "Real Economic Carrying Charge" (RECC) intended to account for the replacement cost of load related investments to some extent.

Marginal cost witnesses in the proceeding were asked to discuss the Commission's costing methodologies in gas, electric and telephones and to rank the level of competition that exists for each industry. Witnesses agreed that the telephone industry is the most competitive of the three and also is developing a costing methodology, the Total Service Long-Run Incremental Cost (TSLRIC) for pricing unbundled local service that includes the cost to replace the entire system, a far more comprehensive approach that the LRMC methodology used in gas. SoCalGas witness Collette labeled the TSLRIC as a "scorched earth" approach.

Witnesses placed the electric industry as the least competitive today and state that its marginal cost methodology is largely confined to measuring incremental load growth, with a large scaling factor necessary to reconcile marginal cost revenues to the

8 Walter Nicholson, Intermediate Economics and Its Application, fourth edition, Dryden Press, 1987, p. 615.

embedded revenue requirement. CIG/CMA notes that the Commission does not intend to price the emerging competitive market in generation on a marginal cost basis.

Parties agree that the gas industry is between the telephone and electric industries in its movement toward competitive markets. While its marginal cost recommendations go beyond the measurement of incremental load growth, ORA states its replacement cost approach is modest by comparison to TSLRIC.

We also note that we did allow the addition of replacement costs to the marginal costing methodology in PG&E's last BCAP (D.95-12-053). However, we do not view that decision as precedential because it was based solely on the circumstances surrounding PG&E's resource plan involved in that case.

The second issue we address is whether adoption of the replacement cost adder in this proceeding violates the Global Settlement. As SoCalGas points out, the settlement only allows refinements that contribute to accuracy, internal consistency, and completeness in estimating marginal costs, but does not allow changes which shift costs towards other goals. While pure economic theory argues for inclusion of replacement costs in a true long run marginal costs methodology, the Global Settlement does not allow a methodology change of this magnitude which goes beyond a mere "refinement" and results in a significant cost shift not envisioned by the signatories to the Global Settlement. Even if the Global Settlement could be overlooked, which this decision finds it cannot, the Commission should more properly consider a change of this magnitude in a reexamination of our natural gas strategy and policies. In that venue, the Commission should revisit the larger notion of using the adopted LRMC methodology to allocate costs between customer classes in the as industry. For these reasons, we reject ORA's proposal to include replacement costs in the LRMC methodology.

3. Core Peak Day Reliability Study

SoCalGas proposes changes to the core peak day reliability criteria based on a core peak day reliability study presented in its 1993 BCAP. SoCalGas states the study strongly indicates that the current 1-in-75 year standard is too conservative, and therefore it proposes a 1-in-35 year standard, a change from using a 36-degree F extreme peak day design criterion to using a 38-degree F criterion.

While ORA does not take issue with SoCalGas' proposal to change its extreme peak day design criteria, it does raise concerns about the pricing implications of using this as a cost allocator. This issue is discussed above in resource planning.

TURN accepts SoCalGas' proposed standard for purposes of this case, but recommends that the Commission examine the issue further in the next BCAP. TURN testifies that in this proceeding SoCalGas determined that the reduced reliability standard would lower costs to the core by $4.2 million, based solely on a reduction of 170 MMcf/d in the core marginal demand measures (MDMs) for medium pressure distribution and storage withdrawal, both of which are based on forecasted peak day demand. SoCalGas' analysis assumes absolutely no changes in its resource and investment plans or its unit marginal costs, although a logical conclusion would be that a reduction in peak demand would result in reduced costs for distribution and storage withdrawal investments. TURN recommends:

> "that SoCal be directed to present a more complete analysis in its next BCAP that examines the full cost and cost allocation ramifications of three alternative reliability standards. I would initially suggest 36, 38 and 40 degrees for this purpose. The showing should indicate how resource plans, unit marginal costs and core cost allocation would be impacted by the differing reliability standards. Only with this information will the Commission be in a position to make the most informed decision on this critical issue.

> "SoCal should also be required to perform a new core customer value-of-service study along the same lines as the Commission has required of PG&E. SoCal did not perform a new study for this proceeding, but simply relied upon the one that it presented in the last BCAP. That analysis was critiqued by both ORA and TURN but D.94-12-052 did not address the study at all, apparently because no one at that time was proposing to use it for any regulatory purpose...The company must finally be called upon to address the issues raised by ORA and TURN in the last BCAP, including TURN's recommendation that SoCal analyze and report on alternative load management tariffs for core customers which would provide a high transportation rate on peak days and lower rates at other times, thereby enabling customers to reduce their bills by limiting their peak day usage." (Exhibit 68, pp. 40-1.)

We find it reasonable to adopt SoCalGas' proposed 38-degree peak day design criteria for this proceeding. We are interested in the analysis recommended by TURN, but given our commitment to begin a review of our Natural Gas Strategy, it would be unwise to direct too many issues to a future BCAP as TURN suggests. It is unclear to us whether a revised gas strategy will recommend continuation of future cost allocation proceedings. Therefore, we direct the Executive Director to have staff include this issue in their recommendation for a gas roadmap which will follow our Natural Gas Strategy.

B. <u>Transmission Marginal Demand Measure (MDM)</u>

CIG/CMA proposes to change the current MDM of cold year throughput to a weighted average (70/30) of extreme peak day and cold year criteria. It states this is the more appropriate allocator as the predominant drivers for the specific transmission expansion projects reflected in SoCalGas' resource plan are a combination of extreme peak day and firm service requirements. It states this change in MDM is permitted under the Global Settlement provision that permits reconsideration of MDMs if the planning criteria change so that the original MDM no longer reflects the incurrence of future costs. CIG/CMA states adoption of its proposal would decrease noncore rates by 18%.

SoCalGas does not support CIG/CMA's proposal, but its witness Martin Collette notes that if the Commission adopts TURN's proposed new customer only (NCO) methodology for marginal customer costs, such an inroad into the Global Settlement would seem to invite other modifications as well, including CIG/CMA's proposal to modify the transmission MDM (Tr. 8/1901-2).

ORA and TURN oppose CIG/CMA's proposal, stating it has failed to justify a change in the MDM. TURN testifies the workpapers SoCalGas filed with its application indicate that extreme peak day is not the driving factor for transmission investments, rather the controlling condition is the 1-in-10 year (noncore) firm service day requirement. Further, if CIG/CMA were correct, then SoCalGas has misstated the impact of changing the core reliability criterion. (Ex. 68, p. 14.)

ORA also finds the proposed change to be precluded by the Global Settlement because there is no evidence that SoCalGas has changed its planning criteria. Further, ORA states that it questions the use of design criteria with a low probability of occurrence being used for cost allocation purposes. It recommends this be addressed by the Commission in the future; it did not address the issue in this proceeding because in ORA's view it was precluded by the Global Settlement.

Discussion

CIG/CMA advances a similar position to the one it sponsored in the original LRMC proceeding. In D.92-12-058, we did not accept its proposal to use extreme peak day for SoCalGas. CIG/CMA has not presented additional justification here to cause us to reevaluate the issue.

TURN points out that SoCalGas' transmission resource plan did not change at all based on the proposed redefinition of extreme peak day from 36 to 38 degrees, which impacts peak day demand by a quite substantial 170 MMcf/d. We agree with TURN that if peak day demand is really the driving factor for transmission investment, one would expect to see some adjustment to the resource plan as a result of such a change.

Since this record contains no evidence that SoCalGas' resource plan has changed as a result of changes in extreme peak day, CIG/CMA has also failed to establish that its proposal meets the criteria set forth in the Global Settlement for a change in MDM during the settlement period:

> "The MDMs used to allocate costs could possibly be changed if SoCalGas' planning criteria changed to the degree that the original MDM no longer reflected the incurrence of future marginal costs." (Exhibit 71, Appendix A, p. 24.)

Therefore, we should retain cold year throughput as the cost allocator for transmission investments in this proceeding. This issue will be revisited in our gas strategy proceeding when the resource planning process as a whole is thoroughly analyzed, as discussed in the resource plan section.

C. Storage MDMs for Load Balancing

Based on its load balancing study, SoCalGas proposes to change the MDMs for the three load balancing functions - injection, inventory and withdrawal. SoCalGas proposes to change the load balancing injection MDM from summer season throughput to summer weekend imbalances since summer weekends are when peak injection activity occurs.

SoCalGas proposes to change the load balancing inventory MDM from an equal cents per therm allocation to the noncore to an allocation based on cumulative imbalance above inventory reservation using customers' average November inventory imbalance. SoCalGas cites November as the peak month for required load balancing inventory and states all customers should be charged based on their monthly imbalance. SoCalGas' proposal results in core customers being allocated 27% of this load balancing function.

SoCalGas proposes to change the load balancing withdrawal MDM from an equal cents per therm allocation to the noncore to an allocation to the noncore based on near peak day usage. SoCalGas states this methodology is appropriate because withdrawal facilities are needed to accommodate noncore supply underdeliveries expected to occur on the days leading up to a peak day incident.

SoCalGas' proposals are supported by CIG/CMA and Edison.

ORA and TURN support SoCalGas' injection and withdrawal proposals but not its load balancing inventory proposal. Both strongly object to any load balancing inventory costs being allocated to core customers when the core already has a reservation of 70.0 Bcf (60% of SoCalGas' storage inventory) that it fully utilizes only in rare circumstances. The excess capacity, therefore, is available to meet the core's inventory load balancing requirements in most cases. ORA also questions SoCalGas' use of November as its peak month since November is not in the injection season but rather the withdrawal season.

Enron opposes SoCalGas' proposal to allocate load balancing injection costs on weekend imbalances, recommending the Commission retain the existing MDM until SoCalGas presents a more detailed study. Enron also objects to core customers being assigned load balancing inventory costs, stating this is in direct conflict with D.94-12-52, the Commission's decision in the last SoCalGas BCAP, an issue also raised by ORA and TURN.

Enron also questions SoCalGas' use of November as the peak month required to provide load balancing inventory, citing SoCalGas' testimony that the cumulative imbalance reflected in November 1994 "may reflect certain unusual activities by its customers" (Ex. 1, I-23.).

Discussion

SoCalGas' proposals to change the MDMs for load balancing injection and withdrawal are reasonable and should be adopted. While Enron asserts that SoCalGas should directly address the customers who are responsible for large overdeliveries on summer weekends, we have addressed that concern in the earlier storage capacity section. Summer weekends are the peak period for load balancing injection. We have directed our Executive Director to have staff include storage issues in our reexamination of our Natural Gas Strategy. Routine overdeliveries of up to 1,000 MMcf/d on summer weekends should not be allowed to continue since the load balancing inventory reservation is 355,000 MMcf/d and the total system injection capability is 803,000 MMcf/d.

While SoCalGas' load balancing study for inventory shows November imbalances for the core, we question why this occurred. As ORA states, November is not included by SoCalGas as an injection season month, but rather a withdrawal season month. TURN's testimony is persuasive on this issue:

> "If indeed significant amounts of core gas are being stored in excess of the adopted inventory reservation, then SoCal is the party primarily responsible for that result, since it manages the core portfolio...This is not to say that I would necessarily object to the core's contracting on a short-term basis for available inventory capacity in excess of its 70 Bcf reservation, if the overall economics of such a course of action made sense. However, simply running up an excess amount of inventory and then using that fact as the basis for allocating load balancing costs to the core does not make any particular sense to me." (Exhibit 68, p. 52.)

SoCalGas has not met its burden of proof that the MDM for load balancing inventory should be changed. The allocator should remain the same as that adopted in D.94-12-052 and for the same reasons we gave there:

"In D.93-02-013 we adopted an equal cents-per-therm allocation for load balancing, while we awaited a 'better cost allocation method'. We have adopted a 'better cost allocation method' for PG&E, and SoCalGas' core ratepayers should be accorded similar relief from their ongoing subsidy of noncore load balancing services. Unless they subscribe to unbundled storage services, noncore customers have (and pay for) no storage rights. They rely upon SoCalGas' load balancing facilities every time their gas deliveries are even slightly out of balance with actual consumption. In contrast, core customers already have (and pay for) large reservations of storage capacity that can also provide for their load balancing needs the vast majority of the time. To allocate the costs of facilities reserved for system load balancing on a volumetric basis to these two very distinct groups is not reasonable. Even though not perfect, TURN's proposed allocation of load balancing costs is much fairer than the status quo and should be adopted." (Mimeo, p. 46.)

D. Replacement Cost of Distribution Mains and Service Lines

Under the LRMC methodology adopted in D.92-12-058, a Real Economic Carrying Charge (RECC) factor is used to levelize the stream of future payments in constant dollars associated with growth-related investments, with a replacement cost multiplier (RCM) factor added to service lines and distribution mains to reflect the assumption that replacement costs will be higher than initial installation costs. In D.95-12-053, the Commission adopted PG&E's recommendation to eliminate the RCM factor as new technology has lowered the cost of replacement. SoCalGas proposes to retain the RCM factor; ORA and TURN recommend eliminating it.

SoCalGas testifies that it does not agree with PG&E's opinion that "technology of replacement installations is evolving rapidly in the direction of reduced costs" (Ex. 3, Chap. O-10). It states about 50% of its existing service lines are already plastic pipe so it will not enjoy same savings as PG&E by being able to insert plastic pipe into old steel lines. It states its workpaper data on recently-completed new business and replacement investment projects support retaining the estimated RCM factors of 1.08 for service lines and 1.25 for distribution mains.

ORA presents three reasons in support of eliminating the RCM: (1) the technology of replacement installations is evolving rapidly in the direction of reduced costs; (2) the RECC factor is already adjusted upward through the inclusion of a high negative salvage factor reflecting the high costs of removing the worn out facilities; and (3) there was evidence indicating that PG&E makes regular arrangements with other utility providers to determine trenching and paving activities.

TURN supports ORA's proposal and also testifies that it is highly inconsistent for SoCalGas to include an allowance for speculative higher costs for replacing mains and services which fail over 30 years from now without including the real costs of replacing transmission or storage facilities over the next 15 years or including a component in customer costs for equipment which fails this year. (Exhibit 90, p. 6.)

Discussion

We find ORA and TURN's position persuasive on this issue. SoCalGas should be able to institute the same level of efficiency and innovation as PG&E over the next thirty years. Therefore, we remove the RCM factor from the calculation of replacement costs for service lines and distribution mains.

E. Marginal Customer Costs

1. Rental Method v. New Customer Only (NCO)

SoCalGas, ORA, CIG/CMA, and Edison recommend the retention of the rental method as the correct methodology for measuring marginal customer capital costs. Under the rental method, the costs of hooking up a new customer are annualized to develop a unit marginal cost. This cost is then multiplied by the total number of customers to derive total marginal customer cost revenues. The methodology does not distinguish between new and existing customers but rather assumes customers will pay to rent their equipment each year at the annualized charge. ORA believes the rental method sends accurate price signals to customers.

SoCalGas, CIG/CMA, SCUPP/IID, SDG&E, and Edison state that adoption of the TURN's new customer only (NCO) methodology would violate the provision of the Global Settlement regarding changes to MDMs: "The MDMs used to allocate costs could possibly be changed if SoCalGas' planning criteria changed to the degree that the original MDM no longer reflected the incurrence of future marginal costs." (Ex. 71, Section II(8)).

TURN recommends the NCO method, the same methodology the Commission adopted for PG&E in its last BCAP and that it has adopted for both PG&E and Edison in electric ratemaking. The NCO method divides marginal customer costs into two parts for revenue allocation: (1) the capital cost of hooking up new customers is multiplied by the number of new customers in each class; then, (2) ongoing O&M expenses (customer accounting and collections and the cost of maintaining meters and services) are multiplied by the total number of customers in each class.

TURN testifies its method improves economic efficiency by sending the correct price signal to each customer class. It states that under the rental method, existing customers have been systematically overcharged for the costs of access equipment for years. (Exhibit 90, pp. 3-5.)

TURN states its proposal does not violate the global settlement provision regarding changes in MDMs because (1) the Commission in D.92-12-058 did not designate the cost allocator for customer costs as an MDM because customer costs are not demand related; and (2) D.92-12-058 explicitly held open the option of moving to this approach in future proceedings when we stated we might revisit NCO if the "trial run" approved for PG&E's electric proved successful.

Discussion

The NCO method is preferable to the rental method as it improves both the price signal to the customer and costing accuracy. Parties have not presented any new evidence in this proceeding that causes us to change the conclusion we reached in PG&E's last BCAP, D.95-12-053, or Edison's GRC, D.96-04-050.

The issue of whether adoption of the NCO in this proceeding would violate the terms of the Global Settlement is more complex. D.92-12-058 did not categorize the cost allocator as an MDM. In D.92-12-058, we built on electric marginal cost methodology which classifies functions as demand, customer, and energy related. We also stated in D.95-12-053, "Marginal customer costs are the cost of customers' access to the utility's gas system....These costs are all customer-related, not demand related." (Id. at 29).

However, the language in the Global Settlement classifies all marginal cost allocators as MDMs, and ORA continues this practice in its testimony. (Ex. 68 at 11-3.) In several sections of the Global Settlement, SoCalGas cites language that references the cost allocator adopted by D.92-12-058 for marginal customer costs, total number of customers, as an MDM. Section II(8) of the settlement precludes changes to an MDM unless SoCalGas' planning criteria change to the degree that the original MDM no longer reflects the incurrence of future marginal costs. While it could be asserted that the existing allocator, total number of customers, never did reflect SoCalGas' planning criteria, no party makes this assertion.

Therefore, based on the language contained in the Global Settlement, we retain the use of the rental method for interclass cost allocation for this BCAP period. We find, however, that the NCO is the preferred methodology and we therefore use it in this proceeding for LRMC allocation within the core class and also for evaluating core rate design proposals. Pursuant to D.92-12-058, the

Commission will again review LRMC methodology for SoCalGas in its 1999 BCAP proceeding.

2. Service Line, Regulator, and Meter (SRM) Costs

ORA proposes a 15% reduction to SoCalGas' SRM cost proposal. ORA's proposal is based on its finding that SoCalGas' projected SRM facility capital additions used in its budget process are significantly lower than those resulting from its historic data for the period 1990 through 1994.

TURN recommends an adjustment for single-family service main extension costs paid by developers and for an adjustment to meter reading expense allocation based on SoCalGas' new study. It also testifies that SoCalGas has failed to include O&M costs associated with exclusive use facilities assigned to large industrial, UEG, and wholesale customers as required by D.92-12-058.

SoCalGas in rebuttal to ORA states that comparing budget projections to the historical data is an appropriate check on the reasonableness of the company's figures. However, it criticizes ORA's comparison as based on changes in the number of active meters when it should be based on the change in the number of connected meters.

In response to TURN, SoCalGas revises the single-family residential marginal service line investment cost downward from $657 to $475 to reflect the large contribution from developers as a result of new service life extension rules that went into effect in 1995.

Discussion

Both TURN and ORA accept SoCalGas' revised figures for purposes of this proceeding. Therefore, we adopt this proposal. We also acknowledge ORA's recommendation that SoCalGas should provide the following information with respect to its active meters and connected meters: (1) clear definition for each category; (2) an explanation of how it collects the data for each category; and (3) an illustration of how it uses each category and for what purpose. We will order SoCalGas to provide this information in the appropriate forum designated by the procedural roadmap following our Natural Gas Strategy. In providing this information, SoCalGas is directed to include the O&M costs associated with exclusive use facilities assigned to the noncore in its marginal cost calculations.

F. Other Allocation Issues

1. Company Use of Transmission Fuel

SCUPP/IID proposes to eliminate transmission compressor fuel as a component of marginal costs. It states that this cost represents a short-run, out-of-pocket cost, and it is only convention since the LRMC implementation decision that has kept it in the LRMC calculation.

SoCalGas, ORA, and TURN recommend retaining the existing methodology. TURN states that compressor fuel is probably the purest example of a true marginal cost on the entire utility system. Further, it states that SCUPP/IID has not even attempted to explain how the elimination of an entire marginal cost category would comply with the cost allocation restrictions of the Global Settlement.

We find SCUPP/IID has not presented sufficient justification to cause us to change the existing treatment. We therefore, will continue to treat compressor fuel as an LRMC component.

2. ARCO Lease

TURN proposes to treat the ARCO lease costs as a part of transmission O&M expense in the LRMC calculation rather than as a separate line item in the cost allocation. It states this item was given separate line item treatment in the last BCAP because D.94-07-061, which approved recovery of a portion of ARCO lease costs in rates, was issued after testimony in the BCAP had already been submitted. TURN states that there is no reason to continue this treatment on an ongoing basis: ARCO costs should be part of transmission O&M, just like the Long Beach pipeline lease.

SoCalGas is the only party to support retaining the existing treatment. It does not provide an explanation for its position.

TURN presents sufficient justification to change the existing methodology. Therefore, we treat ARCO lease costs as part of transmission O&M.

3. Zone Rate Credit

SoCalGas proposes to maintain the zone rate credit eligibility limitations on Wheeler Ridge volumes established in its last BCAP and to prospectively return the credits this generates to its customers. The primary limitation is to prevent customers who use eastern zone transmission facilities from receiving the credit.

TURN supports SoCalGas' proposal but is concerned with the fact that SoCalGas kept the revenues generated by this limitation in its current BCAP period. TURN states that while the Commission did not specifically state that the revenues resulting from the limitation should be tracked so that they could be returned to customers, there is also nothing in D.94-12-052 suggesting that the Commission intended for SoCalGas to keep the revenues. TURN recommends we direct SoCalGas to explain how past savings resulting from the limitation have been or will be returned to ratepayers.

We adopt SoCalGas' proposal because it provides the correct treatment for the revenues. For the same reason, we adopt TURN's recommendation and direct SoCalGas to file an advice letter within 20 days showing how past savings resulting from the limitation have been or will be returned to ratepayers.

G. Reconciliation of Marginal Cost Revenues to Embedded Revenue Requirement

SoCalGas, CIG/CMA, SCUPP/IID, and Edison propose maintaining the existing scaling methodology, the Equal Percent of Marginal Cost (EPMC) approach, adopted in D.94-12-052. This is the same methodology used in electric ratemaking proceedings.

Long Beach recommends no scaling be applied to wholesale customer rates as the difference between revenue requirement and marginal cost revenues represent costs related to serving retail customers, not wholesale loads. Long Beach's proposal is an interim measure since Long Beach prefers its rates be set at embedded cost but did not submit a specific proposal in this proceeding. SCUPP/IID specifically objects to wholesale customers being granted an exemption from the scaling mechanism.

ORA testifies it has identified potential problems associated with scaling that warrant future investigation. Its findings are discussed in the earlier resource planning section. ORA states that the difference between marginal cost revenues and the embedded revenue requirement appear to be related to stranded, or uneconomic, investments. It recommends this issue be examined in the broader context of the overall framework of LRMC methodology. It does not object to EPMC being used in this proceeding.

The record in this proceeding raises concerns regarding the scaler but does not present an alternative that we should adopt. The testimony of Long Beach does not establish that the problems with the EPMC are solely related to wholesale customers or that exempting these customers would be a fair remedy. We therefore retain the existing methodology. We also note that fundamental changes to the LRMC methodology should only be considered in a generic proceeding such as the one we are considering opening to reexamine our statewide gas policies.

IV. Interstate Pipeline Capacity Costs

This section addresses cost allocation issues associated with SoCalGas' contracts for interstate pipeline capacity on the El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) pipelines. Contested issues in this BCAP emanate from the fact that SoCalGas recently reduced the volume of firm capacity held under long-term contract. This is the first time SoCalGas' firm capacity commitments have changed since the Commission in D.91-11-025 established the allocation of firm capacity costs between core and noncore customers as part of its efforts to promote more customer choice in interstate transportation markets for noncore customers.

In January 1996, SoCalGas exercised its contract right to step down capacity on El Paso from 1,450 MMcf/d to 1,150 MMcf/d. In November 1996, SoCalGas reduced Transwestern capacity from 750 MMcf/d to 300 MMcf/d.

The capacity stepdowns will help alleviate SoCalGas' stranded costs of interstate pipeline capacity, especially over the longer term. For the next few years, however, SoCalGas expects to pay a substantial surcharge over the base rates for its 1,450 MMcf/d of remaining interstate pipeline capacity. These transition cost surcharges are provision of comprehensive settlement agreements separately negotiated with each of the pipelines to help mitigate the risk associated with the unsubscribed capacity. The Federal Energy Regulatory Commission (FERC) adopted the Transwestern settlement on July 21, 1995 (72 FERC ¶61,085) and the El Paso Settlement on April 16, 1997 (79 FERC ¶61,028).

Issues to be resolved in this proceeding include the allocation of SoCalGas' firm pipeline capacity, the allocation of the costs and benefits associated with the reduction of contract obligations on El Paso and Transwestern, and the amortization of the Interstate Transition Cost Surcharge (ITCS) account. Policies with regard to many of these issues have been established in prior Commission proceedings.

Furthermore, in D.95-12-037 the Commission ordered SoCalGas to establish a tracking account to record the savings associated with the pipeline capacity relinquishments. In this BCAP decision, we will clarify and define the disposition of interstate pipeline charges paid since January 1996, including the treatment of any refunds that SoCalGas has or will receive from El Paso or Transwestern.

A. Core Reservation

SoCalGas proposes to reserve 1,044 MMcf/d of interstate capacity for the core market with an allocation of 744 MMcf/d on El Paso and 300 MMcf/d on Transwestern. This proposal reflects a 13 MMcf/d reduction in the current core reservation as an adjustment for core customer migration to the noncore class. SoCalGas' proposal is supported by Edison, SCUPP/IID, and CIG/CMA.

ORA believes that the core capacity reservation should be reduced to 977 MMcf/d based on an updated forecast of core's cold year requirements for the BCAP period. TURN urges the Commission to eliminate the core reservation altogether. TURN maintains that all of SoCalGas' pipeline capacity should be released to the secondary market to ensure that the core portfolio reflects competitive market prices. Under this unbundling proposal, all gas users would share in the stranded capacity costs equally, and the Commission could remove the current 10% cap on the ITCS allocated to the core. If the Commission retains a core reservation, TURN supports ORA's recommendation.

Enron also advocates the elimination of the core reservation and the immediate unbundling of interstate pipeline capacity from core rates. At a minimum, Enron and Enserch want core transportation service to be excluded from the core reservation.

SDG&E supports increasing the core reservations to 1,126 MMcf/d through 2006. SDG&E's calculation is based on the 1,067 MMcf/d core reservation initially adopted in D.91-11-025, assumes a core subscription reservation, and assigns core the additional 10% capacity that is currently paid for through the allocation of the ITCS account. SDG&E's core capacity proposal excludes capacity for core aggregation service. SDG&E would like core aggregators to be treated the same as noncore and wholesale customers and receive an allocated share of SoCalGas' unreserved El Paso capacity.

<u>Discussion</u>

We are not convinced by the alternatives presented to change our existing policies and revise the core reservation in place today. Although the proposals of TURN and Enron are consistent with the Commission's longer-term policy objectives to fully unbundle gas utility services, eliminating the core reservation in this BCAP, as TURN and Enron suggest, could exacerbate excess capacity costs at a time when SoCalGas' customers will be faced with increased pipeline surcharges and the need to amortize large stranded cost balances. For these reasons, the Commission should maintain the schedule established in D.95-07-048 for the unbundling of interstate reservation charges from core rates by 1999. As provided in that decision, SoCalGas will file implementing tariffs to accomplish this unbundling on or before January 1, 1998.

We intend to consider the issue of the appropriateness of maintaining the core reservation in our upcoming gas strategy proceeding. As we move to a more competitive environment in the gas industry, core customers should be able to choose among comparable suppliers. At present, non-utility firms are not required to maintain a reservation for their customers. The core reservation requirement may well disadvantage the utility in the new market as it seeks to match competitive offerings and disadvantage core ratepayers as well by locking in potentially unneeded capacity. At the same time, however, the Commission must consider the implications of eliminating the core reservation on stranded capacity and thus, stranded costs.

SoCalGas, SDG&E, Edison, CIG/CMA, and SCUPP/IID argue that the core reservation initially adopted in D.91-11-025 reflects a settlement agreement that cannot now be modified or adjusted by the Commission. However, even though the Commission accepted the settlement's proposal to establish an initial core reservation of 1,067 MMcf/d based on 1995 cold year forecast requirements, the Commission did not expect core capacity requirements to remain static over time.[9]

9 D.91-11-025 also adopted an initial core reservation of 1200 MMcf/d of capacity for PG&E. With the expiration of PG&E's El Paso contract on December 31, 1997, the Commission expects PG&E's core

(Footnote continues on next page)

In this BCAP proceeding, the Commission must establish an equitable allocation of the costs associated with SoCalGas' interstate capacity and the benefits of the capacity stepdowns. The core reservation is a threshold issue in this determination. In weighing the alternatives to provide a fair resolution that balances the interests of all parties, we are guided by our findings in D.91-11-025. In that decision, we found the initial core reservation consistent with estimates of core demand during peak periods. (D.91-11-025, mimeo, p. 68).

Putting the core reservation into this context, we are concerned that the downward adjustment of the core reservation in this BCAP proceeding as proposed by ORA, TURN, Enserch, and Enron, would unfairly assign costs associated with core service to noncore customers. San Diego's proposal to increase the core reservation unfairly shifts noncore and wholesale customers' capacity to SoCalGas' core ratepayers.

We will adopt SoCalGas' proposal for a core reservation of 1,044 MMcf/d, including 744 MMcf/d of El Paso capacity and 300 MMcf/d of Transwestern capacity. This reservation appropriately reflects a small downward adjustment from the initial core reservation adopted in D.91-11-025 for core customer migration to the noncore class which has occurred over the past several years. This reservation is consistent with SoCalGas' forecast of 1999 cold year requirements. This core reservation includes capacity for

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(Footnote continued from previous page)
capacity reservation will be substantially reduced. See D.95-07-048.

serving core aggregation customers. It does not include capacity for core subscription service.

The core cost responsibility for the core capacity reservation will include the base transportation rates in El Paso and Transwestern's tariffs and any surcharges on the base rates which FERC has already or may in the future authorize to mitigate the pipelines' risk of unsubscribed capacity. The El Paso reservation charge that SoCalGas has paid since January 1, 1996 is an interim rate subject to refund pending a final decision in the El Paso's General Rate Case Docket No. RP95-363 et al.

It is incumbent upon SoCalGas to ensure proper accounting for and allocation of the refunds from the base transportation tariffs which have been paid since January 1996. The El Paso reservation charge that SoCalGas has paid subject to refund does not include any surcharge associated with the stepdowns, whereas the final rate adopted by FERC in RP95-363 et al. may include a "risk sharing surcharge" over the base rate for the period beginning January 1, 1996. In allocating the pipeline stepdown surcharges incurred since January 1, 1996 and the base reservation charges, this BCAP decision clarifies the intent and disposition of the tracking account ordered by D.95-12-037. To the extent that SoCalGas receives other pipeline refunds, such as the Transwestern refund of PGAR costs, those refunds should also be allocated to the customers who paid the excess costs.

B. <u>10% Core Cap on ITCS</u>

Under the current cost allocation procedures, core ratepayers are allocated a share of the ITCS account in an amount equal to 10% of the core capacity reservation. In effect, this allocation requires SoCalGas' core customers to pay 110% of the core reservation charge.

SoCalGas recommends the Commission maintain the 10% core responsibility for the ITCS based on the Commission's finding in

D.92-07-025 that the core benefits by the 10% excess capacity. CIG/CMA, Edison, and SCUPP/IID support SoCalGas recommendation.

ORA maintains that the allocation of ITCS to core ratepayers should be eliminated. Long Beach supports the elimination of core cost responsibility prospectively, if the minimum bid for SoCalGas brokered pipeline capacity is set at zero. TURN agrees that core ratepayers should have no responsibility for the noncore ITCS account as long as the core reservation is maintained.

Enserch proposes that the core's share of the ITCS should be reduced in proportion to any reduction in the core reservation. If core aggregation service is fully unbundled, core transportation customers should assume a full share of the noncore ITCS costs.

SDG&E's core reservation proposal addresses the 10% ITCS cap issue by increasing the core reservation by 10%. Given the higher core reservation, SDG&E would eliminate core responsibility for ITCS charges after December 31, 1996.

<u>Discussion</u>

As SoCalGas notes, we have previously stated in D.92-07-025 that the competition in noncore markets may ultimately benefit the core (D.92-07-025, mimeo., at 17). In that decision, we allocated responsibility for stranded costs to all customers. We also noted that the core would pay a premium for reliable service and since 10% had been previously found to be a beneficial level of slack capacity, we adopted it as a reasonable figure for determining the core class' responsibility for interstate stranded costs over and above the core reservation. (D.92-07-025, mimeo. p. 19.) In D.94-12-052, we reaffirmed this view by not allowing core customers to avoid interstate stranded capacity costs. Clearly, we have considered the same arguments for relieving the core of stranded cost responsibility in prior decisions. The parties in this proceeding have not persuaded us to change this policy at this time. Therefore, we will maintain our current policy and not eliminate the allocation of ITCS to the core as ORA suggests. In our view, a policy change of this magnitude is not appropriate for a utility-specific cost allocation proceeding and should only be undertaken in the context of a generic statewide rulemaking, such as the one we shortly envision for natural gas.

We clarify that the 10% cap applies to stranded pipeline demand charges for unbrokered capacity. Any additional surcharges should be paid by core and noncore customers based on their capacity reservations. Thus, to the extent these surcharges are already incorporated into core rates, the core should not bear an additional 10% of these surcharges.

C. Capacity Brokering Issues

1. Assignment and Marketing of Noncore and Wholesale Capacity

SDG&E recommends that noncore and wholesale customers have the option to directly use their allocated capacity through prearranged deals at the full as-billed rate. Under SDG&E's proposal, the remaining El Paso capacity would be assigned to noncore and wholesale customers based on the 1991 actual throughput. The capacity not used directly by customers would be brokered for a 10% marketing fee. The cost of the customer's allocated share of capacity, less 90% of any brokering revenues would be billed to the customer as a volumetric surcharge on its monthly bill.

Edison and SCUPP/IID do not object to the direct assignment of SoCalGas' interstate capacity as long as it is voluntary, and the default volumetric ITCS is unaffected by the direct assignment. SCUPP/IID suggests that a customer could take an assignment of capacity in lieu of paying the ITCS charge with an imputed brokering revenue credited to the ITCS account.

Edison and SCUPP/IID oppose SDG&E's proposal to allow SoCalGas shareholders to keep 10% of the revenues associated with brokering noncore capacity. Enserch opposes SDG&E's proposal for the direct assignment of capacity.

Discussion

The Commission would like to explore the feasibility of allowing noncore customers to receive a direct assignment of interstate capacity in lieu of paying ITCS charges. A voluntary assignment mechanism could provide for more efficient use of SoCalGas' interstate capacity and offer customers an additional transportation alternative consistent with our established unbundling policies. The assignment mechanism, however, must be consistent with FERC rules and must not impede competition in the market for transportation service.

Therefore, we direct the assigned ALJ to schedule a workshop with all interested parties within 60 days of the effective date of this order for the purpose of developing a voluntary ITCS capacity assignment mechanism that is consistent with FERC rules. Following this workshop, the ALJ should issue a ruling notifying all parties of the outcome of the workshop and any further procedural schedule.

The record does not support SDG&E's proposal to allow SoCalGas to keep 10% of the capacity brokering revenues. As SCUPP/IID point out, SoCalGas is performing this function now without any incentive. The Commission has no basis for finding that an incentive would result in greater efficiency or that a 10% allocation of the revenues is an appropriate incentive.

2. Posting Requirements

Edison is concerned that SoCalGas periodically uses capacity in excess of the core reservation without posting the internal capacity brokering transactions on its electronic bulletin board system. Edison contends that SoCalGas should be required to post all transactions involving excess capacity that SoCalGas intends to use for the core to ensure that SoCalGas receives the highest price for the released capacity. Edison recommends that the transaction be posted on the bulletin board of the interstate pipeline to provide full notice to all parties. SCUPP/IID supports Edison's recommendation.

Discussion

We agree with Edison that all internal company transactions should be made public to ensure that transactions occur at a fair market price. We require SoCalGas to post such transactions on its Gas Select bulletin board and the pipeline's bulletin board. This will provide public scrutiny to protect the interests of core, as well as noncore, customers. This rule will apply to all prospective internal transactions involving SoCalGas' interstate capacity rights. We will not impute any adjustments for past transactions, since we do not have sufficient information to assess the need for adjustments up or down.

3. Minimum Bid

Long Beach recommends eliminating the minimum bid that SoCalGas establishes when it posts its capacity on the secondary market. Long Beach acknowledges that the minimum bid may help to reduce ITCS costs. However, Long Beach is concerned that the minimum bid results in an overall increase in the cost of gas delivered to California. ORA and TURN support this proposal based on the record in PG&E's pipeline expansion proceeding, A.92-12-043 et al.

SoCalGas, SDG&E, and SCUPP/IID oppose the elimination of the minimum bid. SCUPP/IID argues that there is no evidence to support the hypotheses that minimum bids increase the cost of gas at the California border.

We are interested in Long Beach's proposal and want to explore the issue further before deciding whether to eliminate SoCalGas' minimum bid procedure. This issue should be included in the workshop we are scheduling to develop a voluntary ITCS capacity assignment mechanism.

4. Organizational Separation of Core and Noncore Capacity Brokering Functions

SDG&E recommends that SoCalGas' Energy Distribution Business Unit broker excess core capacity, separate from the brokering of noncore and wholesale capacity which is handled by the Energy Transmission Business Unit. SDG&E believes that the separation would help maximize the value of the core's capacity and could reduce core capacity costs by $6 million per year. SDG&E notes that the Commission could develop a new financial incentive for brokering core capacity in conjunction with SoCalGas' Gas Cost Incentive Mechanism. SoCalGas opposes this proposal.

From the evidence presented, we do not find a need to require SoCalGas to separate its business units and, therefore, do not adopt this proposal.

D. Interstate Transition Cost Surcharge Issues

1. Allocation of the Capacity Stepdown Costs and Benefits

SoCalGas, SDG&E, Edison, SCUPP/IID, and CIG/CMA maintain that noncore and wholesale customers should receive all the benefits of the pipeline capacity relinquishments by being relieved from paying the stranded costs associated with 450 MMcf/d of Transwestern capacity and 300 MMcf/d of El Paso capacity. At the same time, core customers should pay most of the stepdown costs by paying the full pipeline tariff rate including any surcharges for most of the remaining capacity which will be reserved for the core. The parties claim that the Commission established this policy in D.91-11-025, and nothing has changed to justify any modification.

Subject to a modest reduction in the core reservation, ORA agrees that noncore customers should enjoy most of the benefits of the stepdowns. The quid pro quo in ORA's proposal is that noncore customers should pay all of the pipeline transition cost surcharges associated with the stepdowns by allocating these cots to the ITCS account. TURN supports ORA's proposal for allocating the costs and benefits of the capacity stepdowns, if the Commission retains the core reservation.

Discussion

The Commission anticipated that SoCalGas would exercise contract opportunities to relinquish El Paso and Transwestern Capacity not needed for core service. As an incentive to do so, D.92-07-025 directed that the utilities to "eliminate the use of the ITCS for each existing liability on the day that liability is no longer in effect." (D.92-07-025, mimeo., at 41.) At the time the Commission issued the capacity brokering decisions, there was general consensus that the utilities should maintain pipeline capacity to serve core ratepayers and any reductions in capacity obligations would benefit noncore customers by reducing ITCS liability.

Several parties in this BCAP assert that nothing has changed since the Commission issued D.91-11-025 and D.92-07-025 to warrant Commission review of the allocation of the costs and benefits of the stepdowns. Arguing for the status quo, some parties contend that increased pipeline costs were envisioned in 1991. However, in 1992, no one could have predicted that El Paso and Transwestern would enter into comprehensive ten-year rate case settlements with "risk sharing" surcharges in the early years to resolve the pipeline's unsubscribed capacity costs resulting from the contract stepdowns.

Despite these new surcharges, we will maintain our established policy framework until we have reviewed our transition cost policy in a generic, statewide proceeding. We should not dismantle our policy in a piece-meal fashion, one utility at a time. Therefore, SoCalGas' core will pay the full costs of its capacity reservation (1044 MMcf/d) including base rates, an allocation of ITCS equal to 10% of its reservation, and surcharges, and the noncore will pay the remaining cost of 406 MMcf/d in capacity, including base rates and surcharges, through the ITCS.

Because we differentiate between interstate stranded costs based on their origin in either pipeline demand charges versus surcharges, SoCalGas should account for these costs separately. But despite this separate accounting, core and noncore will pay a share of both types of stranded costs in proportion to the current core and noncore allocations of firm interstate capacity.

2. Wholesale Customer Liability for ITCS Charges

Long Beach maintains that, as a wholesale customer of SoCalGas serving core customers, it is eligible for a 10% cap on its liability for ITCS charges under the provisions of D.91-11-025. SDG&E supports the retention of the wholesale ITCS cap, but acknowledges that the cap should be reduced if the wholesale customer reduces its contract for SoCalGas' interstate capacity. If the wholesale ITCS cap is eliminated, Long Beach and SDG&E argue that any increased allocation be applied prospectively.

ORA recommends the elimination of the 10% cap for wholesale customers. In ORA's view, SDG&E and Long Beach should pay the same share of the ITCS as noncore customers, since they declined to take an assignment of SoCalGas' capacity at the full tariff rate.

SCUPP/IID supports ORA's proposal to charge wholesale customers their full share of the ITCS. SCUPP/IID note that the Commission's ITCS recovery methodology has changed each year since 1994 and the core cap has been applied to the costs to be recovered during the coming year without regard to the time of accrual.

Discussion

We agree with ORA that wholesale customers should bear a full share of the ITCS costs if they do not take their full assignment of SoCalGas' interstate pipeline capacity at the full tariff rate. D.91-11-025 gave the opportunity, but not the obligation, to reserve a share of SoCalGas' interstate pipeline capacity for their core customer requirements. The Commission's intent was to treat the capacity assignment for the wholesale core the same as the utilities' own core reservation. Assuming that the assignment was made at the full tariff rate, the wholesale core's liability for ITCS costs would be limited to the same 10% cap as for SoCalGas' core customers.

This decision is consistent with the established precedent on the wholesale core ITCS issue in D.95-12-053. In PG&E's last BCAP, we found Palo Alto, a wholesale customer of PG&E, ineligible for the 10% cap since Palo Alto did not take an assignment of PG&E's capacity at the full tariff rate. Similarly, SDG&E and Long Beach obtain their capacity at market prices and must assume cost responsibility for their share of the ITCS. Long Beach and SDG&E's proposal to eliminate the cost cap for prospective ITCS costs beginning in January 1997 would shield them from liability for the amortization of the accumulated balance in the ITCS account. Considering that SDG&E has not had any assignment of SoCalGas' interstate capacity since July 1995 and Long Beach never exercised the wholesale core reservation option, there is no compelling reason why the full ITCS allocation should be limited to post-1996 costs. Long Beach and SDG&E should pay the same ITCS surcharge as all noncore customers.

SDG&E asserts in its comments on the proposed decision that it continues to hold 60 MMcf/d of firm capacity for core customers and should therefore be eligible for a partial credit under the 10% core cap, pursuant to our determination regarding the City of Palo Alto in D.95-12-053:

> Palo Alto states that PG&E should apply the 10% ITCS core cap established in D.92-07-025 to its wholesale core load, per the treatment of SoCalGas' wholesale core loads in its BCAP, D.94-12-052. PG&E and DRA object, stating Palo Alto chooses to procure its own gas supplies at discounted interstate capacity rates rather than elect to reserve interstate capacity held by PG&E for the core and wholesale core loads at 100 percent of as-billed rates, thereby making it ineligible for the 10% core liability cap. (See D.92-07-025, 45 CPUC 2d 47, 61.)

> SoCalGas' wholesale customers were granted the 10% ITCS cap in D.92-07-025 without the Commission directly addressing whether all the wholesale load obtained capacity from SoCalGas at 100% of the as-billed rate. Palo Alto notes that SDG&E, a wholesale customer of SoCalGas, is currently receiving the benefit of the cap even though, as of August 31, 1995, it no longer holds any SoCalGas capacity at 100% of as-billed rates. This is an issue we will address and correct in SoCalGas' next BCAP.
>
> Therefore, for the reasons stated by PG&E and DRA, we find Palo Alto is not eligible for the 10% core ITCS cap. Should Palo Alto or other of PG&E's wholesale customers elect to reserve core capacity in the future at 100 percent of the as-billed rate, PG&E should apply the 10% ITCS cost cap to the amount reserved for the period they maintain their capacity reservation. (Id. at 55-6.)

Our record here shows SDG&E chose to directly contract for 60 MMcf/d of firm capacity with El Paso and PGT/PG&E Line 401 rather than taking as assignment of SoCalGas' interstate capacity. We find our decision to not grant SDG&E partial credit under the 10% core cap to be consistent with our holding in D.95-12-053 and also consistent with our finding in this decision that SCUPP/IID's proposal to grant ITCS relief for noncore retail customers who have acquired firm interstate pipeline capacity on their own at full as-billed rates is inconsistent with our established policy. (See proposed decision discussion in Section IV.D.4.)

Should Long Beach of SDG&E elect in the future to reserve interstate pipeline capacity from SoCalGas at 100 percent of the as-billed rate, SoCalGas should apply the 10% ITCS cost cap to the amount reserved for the period either wholesale customer maintains its capacity reservation.

3. Amortization of ITCS Account

ORA, CIG/CMA, and SDG&E advocate amortizing the ITCS account balance of approximately $100 million as of December 31, 1996 over the full 31-month BCAP period. SDG&E recommends that customers have the option of prepaying their allocated share of the ITCS. ORA and CIG/CMA do not object to allowing customers to pay their share of the balance in 1997.

Edison and SCUPP/IID recommend that, beginning in 1997, the ITCS should be based on forecasted rather than historical costs. By amortizing the accrued balance in 1997, and then recovering expected costs on an ongoing basis, Edison and SCUPP/IID believe that UEGs will be better positioned for electric restructuring. SCUPP/IID recommends maintaining the ITCS account as a tracking account to ensure that SoCalGas remains at risk for recovery of the ITCS related revenue requirement, consistent with the Global Settlement.

Discussion

We agree that the ITCS account balance at December 31, 1996 should be amortized over the full BCAP period. We find a sufficient record exists to change the methodology to recover ITCS charges on a forecast basis. Alternative payment methods, including prepayment in 1997, may be developed under negotiated agreements as long as the customer pays the appropriate share of ITCS costs. Any agreements negotiated should be filed by Advice Letter for Commission approval and served on all parties to this proceeding.

4. ITCS Relief for Noncore Holders of Intestate Capacity

SCUPP/IID recommends that noncore and wholesale customers who have acquired firm interstate pipeline capacity at full as-billed rates be granted relief from ITCS charges. Under this proposal, eight customers would be allowed to credit their firm capacity costs as an offset to their share of the ITCS. Comparing the noncore capacity contracts to the core capacity reservation, SCUPP/IID argues that, at a minimum, the ITCS cost responsibility should be limited equivalent to the 10% cap on the core reservation.

As part of a comprehensive ITCS polciy proposal presented as a compromise approach, TURN supports giving the eight noncore customers who hold their own firm capacity some relief from ITCS costs. Most other parties oppose the SCUPP/IID proposal.

Discussion

The SCUPP/IID proposal is inconsistent with our established policy. The ITCS provides for the recovery of transition costs associated with SoCalGas' interstate pipeline contracts from all noncore and wholesale customers.

The costs associated with the new pipeline capacity which came into service in 1992 and 1993 are the responsibility of the noncore customers and shippers who entered into private contracts for the new capacity. Similarly, the noncore customers and shippers who obtained SoCalGas' relinquished El Paso capacity in 1991 freely assumed the cost responsibility for that capacity. We are sympathetic to the cost burden on the eight noncore customers who are paying ITCS as well as firm capacity costs. Nonetheless, noncore customers with their own firm capacity have no entitlement to receive special treatment or to be relieved from paying their share of SoCalGas' ITCS liability.

Based on the above discussion, we do not adopt this proposal.

5. Statewide ITCS Surcharge

TURN and SCUPP/IID support an Edison proposal for a statewide ITCS surcharge to reallocate some of SoCalGas' stranded costs to PG&E's northern California service area. The rationale for this reallocation is that PG&E's marketing of Line 401 capacity, coupled with the termination of its El Paso contract in 1997, have or will contribute to SoCalGas' stranded capacity costs.

ORA opposes any cost shift between the two utilities. ORA points out that PG&E's ratepayers should not be penalized for PG&E's marketing of Line 401 or for PG&E's ability to terminate the El Paso contract.

Following the close of hearings, Edison filed a motion to withdraw its testimony on this issue. On October 21, 1996, this motion was granted by administrative law judge ruling.

Discussion

We agree with ORA that there are numerous factors outside of SoCalGas' control that impact ITCS costs and the value of brokered capacity. Just because the Commission could shift costs to PG&E's service area through a statewide ITCS does not mean that such cost shifting would be fair to Northern California ratepayers. Therefore, we do not adopt this proposal.

V. Cost of Gas

A. Purchased Gas Account (PGA) Overcollection

SoCalGas estimates in its October 15 update filing that on December 31, 1996 it will have an $80 million overcollection in the core PGA account and proposes to amortize this balance in rates over a 12-month period.

ORA, Enron, and Enserch testify that the overcollection should be returned to ratepayers as a one-time refund, consistent with the Commission's prior policy for SoCalGas in D.95-09-075 and PG&E in D.95-12-053 and SoCalGas' own proposal in its monthly pricing application, A.96-03-060.

A one-time refund avoids distortions in the price signal sent to customers and is consistent with our policy objectives. Pursuant to D.96-08-037, we deferred implementation of monthly real-time pricing for residential customers and disposition of the PGA balance to this BCAP decision. Therefore, within 30 days of the effective date of this decision, SoCalGas should file by advice letter, with complete workpapers, a one-time refund plan to be effective as soon as possible. The refund plan should use the latest actual balance in the PGA account in making the refund calculation; depending on the date of our decision, the refund balance may include 1997 gas purchases. If the PGA account balance is undercollected rather than overcollected, SoCalGas shall file in this docket, not by advice letter, its proposal to collect this balance.

B. Adopted Gas Forecast

Pursuant to D.96-08-037, we will no longer base core procurement rates on a two-year forecasted gas price but rather set them on a monthly basis. Therefore, the gas price forecast we adopt here will be less critical than in prior BCAPs, its expected use being in the calculation of fuel use and lost and unaccounted for (LUAF) gas.

SoCalGas forecasts a weighted average cost of gas (WACOG) of \$1.62/decatherm (Dth), \$1.76/Dth, and \$1.82/Dth for BCAP years 1, 2, and 3, respectively. Based upon its own independent analysis, ORA forecasts a WACOG of \$1.54/Dth, \$1.64/Dth, and \$1.65/Dth for the same periods. Both forecasts are reasonable but for purposes of this proceeding we prefer SoCalGas'; therefore, we will adopt SoCalGas' WACOG for the BCAP period.

C. Hub Revenues

SoCalGas proposes to assign the revenues it generates from operating its California Energy Hub (Hub), which is a service that links major gas producing sites with metropolitan Southern California areas and provides interruptible parking, loaning, and wheeling services, in the following manner: (1) revenues of \$684,338 received prior to April 1, 1995, to the PGA; (2) revenues received after March 31, 1995, to the core gas cost incentive mechanism (GCIM). It states its proposal recognizes that core flowing supplies are essential to operating this service while providing the company an incentive to offer the service by allowing SoCalGas' to share some of the benefits of the revenue if it keeps gas costs low at the same time. (Opening Brief at 208-9.)

ORA agrees with SoCalGas that core flowing supplies are the key ingredient used to provide Hub Services. ORA opposes SoCalGas' specific proposal to allocate revenues to the GCIM although it does not oppose consideration of financial incentives for SoCalGas associated with provision of Hub services. ORA recommends all net revenues received through December 31, 1996 be allocated to the Core Fixed Cost Account (CFCA) and revenues received after December 31 be tracked and the appropriate allocation addressed in the GCIM, PBR, or BCAP proceeding.

Enserch, Edison, CIG/CMA, and SCUPP/IID oppose SoCalGas' proposal to credit revenues solely to core customers, stating all customers pay for the facilities and provide the gas used by SoCalGas to provide Hub services. SCUPP/IID recommends Hub revenues be credited to the storage load balancing and transmission revenue requirements; the other parties recommend an allocation to all customers based on equal cents per therm.

We agree with SoCalGas and ORA that it is core flowing supplies that are essential to providing Hub services and, therefore, we find that Hub net revenues should be used to lower the cost of gas to the core, not shared among all customer classes. While SoCalGas and ORA presented different proposals for the accounting treating of Hub revenues in this proceeding, SoCalGas in its April 11, 1997 comments on the alternate proposed decision of Commissioner Knight states that it reached a settlement with ORA covering the treatment of Hub revenues beginning April 1, 1997 and filed this agreement in the Gas Cost Incentive Mechanism (GCIM) proceeding, A.96-06-029, on February 12, 1997. SoCalGas states this agreement provides that Hub net revenues will be included as a credit to the GCIM actual costs and the Hub revenues and expenses will continue to be captured in a separate Hub account. On a monthly basis, the Hub net revenues will be cleared and allocated to the core PGA.

We find SoCalGas/ORA's settlement proposal to be reasonable and we adopt it for treatment of Hub revenues beginning April 1, 1997. For Hub revenues received prior to April 1, 1997, we must look to the recommendations of SoCalGas and ORA in this proceeding. SoCalGas' testifies that booking Hub revenues received before April 1, 1995 to the PGA account is logical because SoCalGas was within its tolerance band in the first year of the GCIM; there is no record here of the effect that booking Hub revenues received between April 1, 1995 through March 31, 1997 to the PGA account would have on the GCIM. This is a historic period of time and placing Hub revenues retroactively under the GCIM mechanism will not encourage the generation of incremental Hub revenues. Therefore, for the period before April 1, 1997, we adopt ORA's proposal to book all net revenues to the CFCA.

D. Minimum Supply Requirements at Blythe

TURN testifies that SoCalGas' system transmission requirements necessitate it maintain minimum flowing supplies at Blythe and that this requirement causes increased procurement costs to the core. It recommends that SoCalGas be required to track in a memorandum account the excess costs it incurs in meeting this minimum supply requirement, i.e. the premium paid for Permian gas delivered at Blythe rather than San Juan basin gas delivered at Topak, and that these costs be properly allocated as transmission costs, not procurement costs, in the next BCAP.

SoCalGas does not support this recommendation, stating the tracking would be an onerous requirement.

We will not require SoCalGas to track these costs at this time. We expect to pursue the dividing line between transmission and distribution in our upcoming Natural Gas Strategy proceeding and prefer to leave cost allocation as it is today until we engage in that analysis.

E. California Producer Exchange Revenues

SoCalGas forecasts that for the 1996 BCAP period, California Producer Exchange revenue will decrease significantly from historical levels due in large part to changes in the contractual rights under certain exchange agreements.

ORA and TURN testify that when these volumes move as regular noncore transport rather than exchange volumes, there will be a change in the allocation of risks and benefits set by the Global Settlement. The core will lose its allocation of exchange revenues under the balancing account treatment prescribed for these volumes and SoCalGas' shareholders would gain the benefit of increased transport revenues even though actual throughput volumes on the system have not changed. Therefore, ORA recommends these volumes continue to be imputed as producer exchange revenues for the BCAP period. (Ex. 68, Chap. 3-2.)

TURN does not oppose SoCalGas transferring these volumes to transport as there may be incremental revenues to be gained by the different rate structures, but the core should remain revenue neutral. Therefore, it recommends SoCalGas be directed to continue recording exchange revenues at the previously-existing contract rate, and to the extent transport revenues are higher, SoCalGas be allowed to record the difference as noncore transport revenue, to the benefit of shareholders. TURN testifies that SoCalGas' ability to earn incremental revenues should not come at the expense of the core when it is SoCalGas that is in control of the situation. (Ex. 68 at 37.)

SoCalGas opposes both ORA and TURN's proposal, stating that two of the contract changes at issue in the forecast are the result of exchange contract provisions that were established long before the adoption of the Global Settlement. (Opening Brief at 227.)

We find TURN's position on this issue persuasive and therefore adopt its recommendation. SoCalGas should continue to record exchange revenues that move as transport revenues at the previously-existing contract rate; any incremental revenues should be recorded as noncore transport revenue.

F. Throughput Forecasts

No party opposes SoCalGas' forecast of volumes and revenues for Interutility Exchange service between SoCalGas and PG&E under the Master Exchange Agreement or SoCalGas' Enhanced Oil Recovery forecast. Therefore, we adopt both forecasts.

G. Core Brokerage Fee Study

SoCalGas was ordered in D.94-12-052 to conduct a study of core brokerage fee costs, in order to remove procurement costs from transportation rates. We found that "given the utility's dominant market position, it appears that the lack of a separate brokerage fee may be having an anticompetitive effect on the core procurement market" (Id. at 55).

SoCalGas testifies that its study is based on the total cost of gas brokerage services, and clarified that the study is based on the costs that would be eliminated if SoCalGas stopped procuring gas. Most of these costs are incurred in the Core Commercial/Industrial classes because most of the competition for procurement is in this sector. SoCalGas states that while 20 to 25 percent of core commercial and core industrial customers are transport-only customers, core aggregators haven't really gone after the residential market, which makes up approximately 95 percent of SoCalGas' core customers.

Enron challenges the core brokerage fee proposed by SoCalGas as being understated and recommends that SoCalGas be required to perform a complete study including all of the costs of the procurement function. Enron questions several items that it believes SoCalGas excluded from the study and also questions the quantification of several items in the study. Enron points to the following items:

1. SoCalGas excluded costs related to procuring gas for residential customers. SoCalGas included costs related only to "selling" gas, and stated that the exclusion was based on a lack of competition in the residential market.

Enron challenges this because the residential market has some access to aggregators.

2. Legal fees were not itemized in the study. Enron states that legal services would be necessary for the negotiation of gas supply, existing delivery contracts, regulatory proceedings, etc.

3. No sales manager labor was included, and only 1 percent of account executive labor was included in the study. Enron claims these amounts are too low since core procurement represents about 96 percent of total core throughput.

4. No customer service costs were included. Enron believes some costs should have been included for questions related to procurement, changing rates, PGA refunds, etc.

5. SoCalGas included only $25,500 for executive management. Enron stated that the cost for executive management should cover management directives to staff on purchasing gas.

6. No residential marketing costs were included because SoCalGas does not deliberately market residential customers for the purpose of selling gas.

7. Finally, Enron objects to the use of only six months of data for the study.

SoCalGas has sufficiently explained that legal costs are represented but not itemized, and marketing costs do not exist for residential customers. On the remaining issues, Enron's questions have merit. SoCalGas' avoided cost calculation does not reflect all the funds we expect it will expend to compete in the core procurement market. For example, under current market conditions only five percent of core customers are targeted for Core Aggregation Transportation, limiting the amount of resources

SoCalGas needs to market gas to the core. However, we do believe that if SoCalGas found the core sector being more heavily marketed by other companies, it would shift resources--not only for marketing, but for executives, sales managers, etc.

Because we do not have an acceptable avoided cost study, we have recalculated SoCalGas' brokerage fee as an average cost using the data that SoCalGas provided in this proceeding (Exhibit 1, Chapter G, Table A). We have not included overhead costs in our calculation because we want to reflect only the cost of the procurement function to the utility. We will not require another study as the regulatory costs are too high. We do not want the utility putting additional resources into such a study, nor do we want the competitors expending their resources scrutinizing and litigating another study. The average cost calculation results in a fee of $0.00201 per therm.

VI. Cogeneration Parity

A. Overview

In this proceeding, SoCalGas, Edison and SCUPP/IID argue for elimination of the collateral discount provided to cogeneration customers. CCC/Watson contends that it should be maintained.

On August 31, 1984, the Governor approved Senate Bill 2303 adding §454.4 to the Public Utilities Code. That section directs the Commission to "establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity..."

In July 1993, the Commission adopted Resolution (Res.) G-3062 which establishes the current methodology used to calculate contemporaneous gas rate parity between UEG and cogeneration customers. This formula essentially determines a weighted average rate for gas utilized by the UEGs and cogenerators, and then sets that average rate as the maximum to be charged to cogenerators. The rate is to be calculated not more frequently than once per month, whenever warranted by the execution (or expiration) of a discounted rate agreement between a UEG and the gas utility. (Res. G-3062 at 13.) The consequential reduction in gas rates to cogenerators is known as the "collateral discount." In SoCalGas' last BCAP in 1994, the Commission adjusted the calculation to eliminate considerations of service level by establishing rates on a class average basis. (D.94-12-052, slip op. at 62.)

B. Positions of the Parties

SoCalGas claims that the collateral discount provided to cogenerators is an anachronistic practice which should be eliminated. In support of this proposition, SoCalGas advances two major arguments: (1) The collateral discount discourages SoCalGas from entering into discounted contracts with UEGs, resulting in the potential for uneconomic bypass, and (2) the collateral discount is inherently unfair because it favors cogenerators over UEGs.

SoCalGas believes that "the recent withdrawal of Mojave Pipeline Company from its Northward expansion plans in no manner diminishes the threat of bypass into California gas markets." (Opening Brief at 105.) In addition to direct bypass, SoCalGas notes that it faces the threat of "bypass by wire," the reduction in load resulting from the displacement of gas-fired generation by more economical out-of-state power generation. SoCalGas believes this competition will be enhanced by the deregulation of the electric industry. SoCalGas argues that, in this competitive environment, the collateral discount serves as an impediment to the negotiation of discounted contracts with UEGs because (1) any discount will decrease the rate charged to cogenerators, reducing SoCalGas' revenues and (2) its out-of-state competitors are not subject to the same requirements. It claims that "contracting with a UEG customer to retain at-risk load, or to capture incremental load, can become 'uneconomic' for no reason other than the fact the regulatory requirement to provide collateral discounts renders them so." (Id. at 111.)

Second, SoCalGas asserts that collateral discounts represent nothing more than a subsidy to cogenerators, favoring them over UEGs. It believes this policy to be a "significant exception to the otherwise contemporary nature of the Commission's policy objectives." (Id at 113.)

SoCalGas argues that parity should be implemented solely at the Commission approved cost-based tariff rate and the effective cogeneration tariff should not include a discount based on contracts the gas utility pursues to retain utility electric load on its system.

Edison proposes that the Commission eliminate collateral discounts or, at a minimum, exempt negotiated agreements between a UEG and SoCalGas that "convert the all-volumetric tariff rate design into a different rate design." (Opening Brief at 43.) In support of this proposition, Edison offers the following arguments: (1) the requirements of § 454.4 are met by setting the default tariff rate for cogenerators and UEGs at parity; (2) collateral discounts are unfair to UEGs; and (3) collateral discounts may preclude SoCalGas from entering into a negotiated agreement with a UEG.

SCUPP/IID also advocates elimination of collateral discounts for cogenerators. SCUPP considers collateral discounts to be grossly unfair because they provide "cogenerators with a systematic, market-distorting, regulatorily induced advantage over utility electric generation." (Opening Brief at 31.) Additionally, SCUPP/IID believes that collateral discounts are preventing SoCalGas from offering discounts to UEGs that would result in incremental gas fired generation. SCUPP/IID alleges that the failure of Los Angeles Department of Water and Power (LADWP) and SoCalGas to come to terms on a recent discount contract was due to the collateral discount.

CCC/Watson believes that the collateral discount for cogenerators should be maintained. It argues that: (1) elimination of the discount would violate the letter and spirit of § 454.4; and (2) collateral discounting does not prevent SoCalGas from entering into any contracts for incremental UEG load.

CCC/Watson alleges that SoCalGas' desired interpretation of § 454.4 violates the statute by charging cogenerators higher rates than UEGs. CCC/Watson calls SoCalGas' suggestion to base rate parity on default tariff rates rather than actual negotiated discounted rates a "sham" implementation of UEG/cogeneration parity. (Opening Brief at 3.)

CCC/Watson notes that, although SoCalGas has faced competition for over a decade, SoCalGas has not provided any evidence of its lack of ability to compete. In fact, CCC/Watson claims that "the only time that SoCalGas faced an imminent threat of bypass by a UEG facility (in the case of Edison's Mandalay facility), SoCalGas successfully negotiated a discounted contract and retained the UEG facility on its system." (Id. at 9.) CCC/Watson questions whether the LADWP example raised by SCUPP/IID was truly a case where a negotiated discount was precluded by the collateral discount. CCC/Watson's skepticism is based on (1) its allegation that SCUPP/IID witness Doering, who testified to the occurrence of this event, was not present during the LADWP/SoCalGas negotiations; and (2) SoCalGas' failure to raise this incident in its own testimony as evidence of its inability to complete.

Finally, CCC/Watson asserts that, to the extent SoCalGas' incremental load concern exists at all, it was created solely by SoCalGas in the Global Settlement. CCC/Watson believes that any shortfall experienced by SoCalGas due to its inability to retain or attract incremental loads should be borne by SoCalGas' shareholders, not by cogenerators.

C. Discussion

1. Statutory Interpretation

Section 454.4 directs the Commission to "establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity." Edison argues that the requirements of § 454.4 are met "so long as the tariff rate for gas used by cogenerators is not higher than the tariff rate established for gas used by an electric plant." (Reply Brief at 18, emphasis in original.) SCUPP agrees. CCC/Watson counters that such a reading of § 454.4, which "disregard[s] the actual rates paid by UEGs that have contracts with the local distribution companies (LDCs) and implement[s] UEG/cogeneration rate parity only on a hypothetical 'default' level" (Opening Brief at 4) can only be "considered a 'sham' implementation" of the statute.

"This Commission's first task in construing a statute is to ascertain the intent of the Legislature so as to effectuate the purpose of the law. In determining such an intent we must look to the words of the statute, giving to the language its usual, ordinary import." (D.95-10-050, slip op. at 5.) Edison's argument rests on an interpretation of the word "rate" in § 454.4 synonymous with "default tariff rate," rather than the actual amount paid by the UEG. We believe that the Legislature intended a broader, plainer meaning.

"Rate" is defined by Webster as "a charge, payment or price fixed according to a ratio, scale or standard: as (1): a charge per unit of a public service commodity." (Webster's New Collegiate Dictionary, 7th Edition, (1970) at 710.) A "charge" is likewise defined as synonymous with "expense," "cost," or "price." (Id. at 140.) These nouns imply an amount actually paid. We have long held that § 454.4 applies to more than simply the tariff rate. Ten years ago, we found that if a cogenerator was willing to contract for service under similar conditions as a UEG customer, that the rates paid by the UEG and cogenerator for gas should be the same. (Re Rate Design for Unbundled Gas Utility Services, 22 CPUC 2d 444, 480.) In SoCalGas' last BCAP, we found that for the purposes of setting the maximum rate chargeable to cogenerators, the UEG gas rate was the amount paid by the UEG for gas at the burner tip. (D.94-12-052, slip op. at 65.) In enacting § 454.4, we believe that the intent of the Legislature was to set the rate paid for gas by cogenerators at a rate not higher than that paid for gas by UEGs.

It is an accepted canon of construction that "a statute should never be construed so strictly as to render it absurd or nugatory." (Walworth v. Bank of America, 9 Cal. 2d 49, 52.) If Edison and SCUPP's strict interpretation of the word "rate" in § 454.4 were to be adopted, SoCalGas could easily avoid lowering the gas rates charged to cogenerators simply by negotiating discounted rates with UEGs. In the aggregate, such a reading would eviscerate § 454.4, reducing it to a nullity. We affirm that it is the rate paid by the UEGs, not the tariff rate, which is the subject of § 454.4. Consequently, we reject Edison's interpretation of § 454.4.

2. Market Competition

SoCalGas' main argument in favor of the abolition of the collateral discount is that it may lead to the loss of existing and or incremental UEG load. SoCalGas posits that a situation may be imagined where UEG customers might be lost because the expense of the collateral discount given to cogenerators would outweigh the anticipated profit from keeping the UEG load. Even if accepted as true, however, the possibility that SoCalGas may lose UEG load to other providers of gas transmission services is not justification for ignoring the statutory requirements of § 454.4. The Code requires that the rates paid for gas by cogenerators may not exceed the rates paid by UEGs. The Code does not require that SoCalGas be able to compete on price with all present and future competitors.

SoCalGas complains that the requirements of § 454.4, as implemented by Res. G-3062, are inequitable. SoCalGas argues first that the collateral discount is unfair because its out-of-state competitors are not burdened by it. SoCalGas has failed, however, to provide any evidence that it has lost UEG load to any out-of-state competitor. Moreover, even assuming arguendo that SoCalGas were to lose UEG load to out-of-state competitors due solely to the requirements of § 454.4, this situation would still not authorize us to ignore the will of the Legislature as manifested in § 454.4.

Second, SoCalGas complains that the law unfairly prefers cogenerators over UEGs by requiring that cogenerator rates be set no higher than UEG rates, but having no reciprocal requirement that UEG rates be set no higher than cogenerator rates. While SoCalGas' sense of fair play is laudable, the inequity complained of is clearly prescribed by the plain language of § 454.4.

We agree with SoCalGas, in theory, that the requirements of §454.4 may put it at a competitive disadvantage in relation to other transportation companies not subject to California law. In addition, we recognize the potential threat to UEG load posed by the "bypass-by-wire" phenomenon. However, we cannot ignore the laws of the State of California, even if, as SoCalGas suggests, market conditions have changed since those laws were first passed. If changes in the Code are required by new circumstances, the task of changing the law falls to the Legislature. To comply with § 454.4, utilities cannot ignore discounts offered to UEGs when establishing gas rates for cogenerators.

3. Application of Resolution G-3062 to Nonvolumetric Contracts

SoCalGas has provided in the record an example of a situation in which, it asserts, a sound economic decision by SoCalGas would result in noneconomic bypass by a UEG due entirely to the collateral discount mandated by § 454.4.[10] Although we are reluctant to give an opinion based on a hypothetical fact pattern, we do so here in order to provide guidance to all parties. We interpret Res.G-3062 based on this hearing record so that future advice letter filings under Res. G-3062 can be handled on a routine basis. To the extent that the facts of a given actual contract are different from this hypothetical, our interpretation of the application of our methodology from Res. G-3062 will differ as well.

As presently constructed, the formula for calculating the maximum rates charged to cogenerators can be represented algebraically as follows:

$$\frac{(Rd * Vd) + (Ru * Vu) + (Rc * Vc)}{Vd + Vu + Vc} = \text{Parity Rate}$$

Where: Rd = the UEG discounted rates
Vd = the UEG forecasted discounted contract volumes
Ru = the UEG standard rates
Vu = the UEG forecasted nondiscounted volumes
Rc = the Cogenerator standard rates
Vc = the Cogenerator forecasted standard volumes

Under the SoCalGas hypothetical, UEG forecasted loads are significantly less than loads forecasted in the previous BCAP. In order to retain UEG load, SoCalGas enters into a hypothetical agreement with UEGs whereby they pay a fixed demand charge for a certain volume of gas, whether actually used or not, and then pay a discounted charge per unit on any volumes in excess of the contracted amount. Specific numbers provided in the hypothetical are as follows:

10 SoCalGas' Opening Brief at 116, referring to Booth/SoCalGas Exhibit 1, p. 7, referring to Data Request No. 1, Question 10, contained in Exhibit BB-2.

<u>Assumptions</u>

Expected 1996 UEG Volumes	165 MMDth/year (yr)
UEG Tariff	5.30 cents/therm
Nondiscounted Cogen Rate	5.30 cents/therm
Nondiscounted Cogen Volume Expected	60 MMDth/yr
UEG BCAP Volume	198.9 MMDth/yr

<u>Rate Design Agreement for All UEG Volumes</u>

Demand Charge Rate	3.30 cents/therm
Demand Charge Volume	165 MMDth/yr
Volumetric Rate	2.00 cents/therm
Incremental Volume Achieved	20 MMDth/yr
Total Forecasted UEG load with Agreement	185 MMDth/yr

Based on these assumptions, SoCalGas calculates that although UEG revenues would increase by $4 million, 20 MMDth at 2.00 cents/therm) the corresponding collateral discount to cogenerators of $4.16 million [11] would cause it to reject the hypothetical contract, resulting in uneconomic bypass. SoCalGas calculates a very large collateral discount by including only revenue from the demand charge of the UEG contract (165 MMDth at 3.3 cents per therm) in the numerator of the Res. G-3062 formula, while including the entire BCAP forecasted UEG volume (198.9 MMDth) in the denominator. This calculation overstates the collateral

11 SoCalGas Cogen Parity Rate = ((165 MMDth * 3.3 cents per therm) + (60 MMDth * 5.3 cents per therm))/(198.9 MMDth + 60 MMDth) = 4.6 cents per therm versus a tariff rate of 5.3 cents per therm. The collateral discount of .694 cents per therm on 60 MMDth yields lost revenues of $4,164,000.

discount because incremental revenues actually realized by SoCalGas are ignored.

CCC/Watson suggests that, for purposes of the collateral discount formula, the incremental volume achieved (20 MMDth/yr) should be increased to an amount which sets total forecasted UEG load with the agreement equal to the BCAP forecast (33.9 MMDth). This results in a collateral discount of only $0.6 million,[12] but still overstates the amount of the discount because it includes 13.9 MMDth/yr of gas at the discounted rate of 2.00 cents per therm which are in actuality never burned.

If the hypothetical UEG contract is examined at the end of the year, it can readily be determined that the nonvolumetric agreement resulted in an effective rate to the UEGs of 4.9432 cents per therm.[13] When included in the Res. G-3062 formula, this results in a collateral discount of only $1.6 million; this is significantly lower than the discounts calculated by SoCalGas or CCC/Watson.

This example highlights the precise problem with nonvolumetric contracts: One cannot know the effective rate paid by the UEGs until the end of the period. Indeed, one cannot know if there is a discount at all. In the hypothetical contract, if the UEGs' actual load is no greater than the 165 MMDth/yr demand

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12 CCC/Watson Cogen Parity Rate = ((165 MMDth * 3.3 cents per therm) + (33.9 MMDth * 2.0 cents per therm) + (60 MMDth * 5.3 cents per therm))/(165 MMDth + 33.9 MMDth + 60 MMDth) = 4.868 cents per therm versus a tariff rate of 5.3 cents per therm. The collateral discount of 0.432 cents per therm on 60 MMDth yields lost revenues of $2,593,000.

13 Cogen Parity Rate + (165 MMDth * 3.3 cents per therm) + (20 MMDth * 2.0 cents per therm) + (60 MMDth * 5.3 cents per therm))/(165 MMDth + 20 MMDth + 60 MMDth) = 5.03 cents per therm versus a tariff rate of 5.3 cents per therm. The collateral discount of 0.269 cents per therm on 60 MMDth yields lost revenues of $1,616,000.

charge volume, there will be no discount. If the load is less, the UEGs may actually pay a higher price per therm than the tariff rate. By their agreement, SoCalGas accepts the risk that UEG volumes will be higher than the demand charge load and the UEGs accept the risk that the load will be less. In contrast, the cogenerator, seeking to obtain the benefit of the UEG's bargain by including the nonvolumetric rate design in the Res. G-3062 formula, has accepted <u>no</u> risk. Although their rates must be set at parity, it would be inequitable to allow the cogenerator to free-ride on the risks assumed by the UEG.

"If a cogenerator is willing to contract for service under similar terms and conditions as the UEG...then the transmission rate should be the same." (22 CPUC2d 444, 480.) The risks allocated between parties in a nonvolumetric agreement such as the one presented here are part of the material terms and conditions of that contract. One cannot logically divorce the potentially lower rates from the inherent risks. Rather than mandate that the cogenerator receive the same discounted rate, regardless of volume commitments, we read § 454.4 to require that when a UEG enters into a nonvolumetric contract with a gas transmission company, cogenerators must be allowed to enter into similar agreements.

The question of what would constitute a similar agreement is one of fact to be decided case by case considering the totality of the circumstances. We are not presented in this proceeding with an actual nonvolumetric agreement between SoCalGas and a UEG. In SoCalGas' hypothetical case, where the risk lies in estimating the demand charge volume, similar contracts could be ones in which the demand charge volumes committed to by the customers were similar percentages of their forecasted usage. Therefore, in this hypothetical, similar agreements could appear as follows:

	UEG	Cogenerator
Forecasted Usage	185 MMDth/yr	60 MMDth/yr
Tariff Rate	5.300 cents/therm	5.300 cents/therm
Demand Charge	3.300 cents/therm	3.300 cents/therm
Demand Charge Volume	165 MMDth/yr	53.51 MMDth/yr
Volumetric Rate	2.00 cents/therm	2.00 cents/therm
Incremental Load Achieved	20 MMDth/hr	6.49 MMDth/yr
Net Rate	4.9432 cents/therm	4.9432 cents/therm

The net rates rendered in the hypothetical are identical because both the UEG and the cogenerator have used exactly their forecasted amounts. Obviously, the greater the usage, the lower the effective rate would be (and vice versa). We recognize that, in contrast to this simple hypothetical example, there may be other factors to be considered when determining the similarity of two contracts. For example, in the hypothetical case, one customer may have a greater degree of control over its load and, consequently, a relatively enhanced ability to meet its demand charge volume. If so, this ability should be reflected in the contract through a demand charge volume that is actually a greater percentage of its forecasted usage than that of the other customer. The similarity of contracts is a matter of fact to be determined based on all material terms and conditions. We will require that SoCalGas negotiate nonvolumetric contracts with cogenerators in good faith in order to arrive at terms similar to those agreed to with UEGs.

The hypothetical "similar" contract does not guarantee that the cogenerator will realize a net rate equal to or lower than the UEG. It provides only that the cogenerator has the same opportunity as the UEG to realize the lower rate. Section 454.4 does not require that cogenerators who enter into nonvolumetric contracts, assuming additional risks in anticipation of greater rewards, be guaranteed rate parity with UEGs. Cogenerators may undertake such risks and then realize effective rates higher than either the tariff or collateral discounted rates.

In summary, we affirm our interpretation of § 454.4 and the methodology used under Res. G-3062 regarding calculation of the collateral discount. We reject SoCalGas' argument that the collateral discount be eliminated. However, we agree with Edison that nonvolumetric rate agreements with UEGs shall be excluded from the calculation of the collateral discount. Nonvolumetric rate agreements, and the forecasted loads of UEGs and cogenerators who enter into them, should be excluded from the collateral discount calculation under Res. G-3062. This does not mean, however, that these rate agreements may be ignored. In order to comply with § 454.4, we will require that if SoCalGas executes nonvolumetric contracts with UEGs, it must agree to contract under similar terms with any cogenerator who so requests.

In its comments on the Proposed Decision, CCC/Watson expresses concern that SoCalGas will be unable to handle the administration of numerous cogenarator contracts. Moreover, CCC/Watson fears that addressing cogenerator parity in this way will prove to be administratively burdensome on this Commission. We share some of CCC/Watson's concerns. We do not intend that this decision result in increased proceedings before this Commission. We do not believe, however, that all cogenarators will choose to enter these types of contracts with SoCalGas. The collateral discount under Res. G-3062 will still act to provide discounted gas rates to cogenerators who remain on standard volumetric contracts. Furthermore, we anticipate that once a standard non-volumetric contract is developed by SoCalGas, it will be a relatively simple matter for it to offer contracts to those cogenerators who request them.

Consequently, we direct SoCalGas to file, by advice letter, a plan to implement the offering of non-volumetric discount gas transportation contracts to cogenerators on similar terms and conditions as those offered to UEGs within 20 days of the effective date of this decision. Such a plan should include a model contract to be used with cogenerators and a methodology for ensuring that operational differences between UEGs and cogenerators are fairly recognized in implementation. CCC/Watson and other parties may respond to SoCalGas' proposed plan to ensure that their concerns are considered.

4. Filing of Contracts

In order to ensure compliance with § 454.4 CCC/Watson proposes that redacted versions of any special contracts entered into between SoCalGas and UEGs be filed by advice letter and be made available to parties seeking the information for legitimate regulatory purposes subject to appropriate confidentiality agreements. (Opening Brief at 21.) Edison strenuously opposes this proposal, noting that in a competitive market for electricity UEGs and cogenerators will be competitors. Edison notes that even if cogenerators are forbidden to disclose the terms of any SoCalGas UEG contract to third parties, they would still be able to use such information to their own advantage.

TURN supports the advice letter filing of the contracts, stating this information is necessary for a number of regulatory purposes.

SCUPP/IID recommends all discount contracts with electricity generators be open to public inspection.

We agree with CCC/Watson that in order for the Commission and interested parties to fully and fairly implement the requirements of § 454.4, there must be disclosure of special contracts entered into between SoCalGas and UEGs. SoCalGas should file redacted versions of all such UEG contracts by advice letter and provide the full contracts and supporting workpapers to the Energy Division and to all interested SoCalGas customers that execute an appropriate confidentiality agreement.

We do not agree with SCUPP/IID that this requirement should extend to all electricity generators, including cogenerators, because we have a long-standing policy that the public interest of holding these contracts confidential outweighs the public interest served by disclosure. In our Resolution L-246, we elaborate on this policy.[14] Therefore, we reject SCUPP/IID's proposal because it is contrary to our policy.

VII. Audit Issues

A. Proposed Audit Adjustments

1. PITCO/POPCO Transition Cost Account (PPTCA)

The Global Settlement provided for sharing between ratepayers and SoCalGas of gas costs paid in excess of market prices to SoCalGas affiliates Pacific Interstate Transmission Company (PITCO) and Pacific Offshore Pipeline Company (POPCO) and transition costs over a five-year period beginning January 1, 1994. The PPTCA was established to record the ratepayer's portion of the buyout/buydown of the settlements associated with PITCO/POPCO and excess PITCO/POPCO gas costs.

ORA said that it reviewed the four components that make up the PPGA tracking account and found SoCalGas' calculation of the fourth component in the PPTCA account, for December 1994, to be both confusing and inappropriate. (Exhibit 58, Chapter 7-5.) This calculation determines the financing costs incurred by SoCalGas to finance the allowable PITCO/POPCO excess gas and transition costs. ORA alleges that SoCalGas included its revenue requirement of $9.3 million in the calculation of the financing costs as if the ratepayers should be additionally financing the

14 Resolution L-246 denies SCUPP/IID's request for access to certain unredacted contracts between SoCalGas and four noncore gas consumers (not electricity producers).

amount being recovered in rates. ORA also claims that SoCalGas made a prior period adjustment of $3.6 million to its April 1995 beginning balance before it calculated the financing cost for the first quarter 1995. ORA characterizes this adjustment as "inappropriate" because it included the revenue requirement in calculating the financing cost. ORA performed its own calculations and found that the PPTCA is overstated by $405,134, and recommends that the account be reduced by this amount.

SoCalGas disagrees with the ORA that the "fourth component" is "both confusing and inappropriate." SoCalGas states that this calculation determines the interest on the unamortized PPTCA balance and admits that the calculation is complicated because the interest calculation is performed on a cash basis instead of accrual basis as with other regulatory accounts. SoCalGas cites the language in the Global Settlement to support its position. (See the definition of transition costs, 55 CPUC2d 452, 464.)

Discussion

We deny ORA's request to reduce the balance in the PPTCA account by $405,134 because we believe SoCalGas has followed the required method for the calculation of financing costs. ORA's auditor was not aware of this method until it was mentioned by SoCalGas' witness. (Tr. Vol. 13/1509.)

2. Fuel Cell Proceeds Memorandum Account

ORA recommends that this account be credited by $103,000. SoCalGas agrees with this recommendation but not with ORA's proposal to close the account. We adopt ORA's recommended credit and direct that the account remain open for the coming period.

3. Audit Expense Account

This account contains SoCalGas' PBR audit expenses. ORA recommends deferral of the balance in the account until the audit is complete. SoCalGas disagrees, stating it wants to recover the costs associated with the audit on an ongoing basis in order to avoid a one-time large recovery.

The $768,000 in the account should not be recovered now; rather, the balance should be deferred until the audit is complete. D.95-08-029 authorizes SoCalGas to file by advice letter to recover this balance; it should follow this procedure when the audit is complete.

4. Research, Royalty, and Memo Account

ORA forecasts a $555,000 overcollection while SoCalGas forecasts a $469,000 overcollection. The difference in forecasts is due to the recorded period used for the forecast. SoCalGas' forecast is based on more recent recorded numbers and, therefore, we adopt it.

5. Catastrophic Event Memorandum Account (CEMA)

SoCalGas accepts ORA's recommendation to defer recovery of approximately $2 million in this account pending the findings of ORA's audit report. It requests, however, that pending a favorable audit report, the CEMA account balance should be included in final 1997 BCAP rates. We find SoCalGas' proposal reasonable and adopt it. In its comments on the proposed decision, ORA provides clarification on the disposition of its audit report. On October 10, 1996, ORA served its report in A.94-12-006 and the matter is still pending in that proceeding. In its report, ORA recommends that SoCalGas' revenue requirement be reduced by $6.6 million.

B. Completion of ORA Audit

ORA testifies that due to time and staff limitations, it was unable to perform an in-depth review of three of SoCalGas' major accounts: the Core Purchased Gas Account (PGA); the Core Fixed Cost Account (CFCA); and the Interstate Transition Cost Surcharge Account (ITCS). It recommends that two of these accounts, the CFCA and the ITCS, remain open for a more in-depth review during SoCalGas' 1999 BCAP.

During cross-examination by SCUPP/IID and SDG&E, ORA testified that its audit of the PITCO/POPCO account did not (1) examine source documentation to determine if the payments recorded in the account were actually paid and that the amounts were correct; or (2) review any of the underlying contracts between SoCalGas and its payees to determine whether or not a payment by SoCalGas would entitle it to receive a later rebate or refund.

At the request of the ALJ, ORA reviewed whether an audit could be done in a more timely manner. At hearing on August 28, it proposed to do an in-depth audit on the CFCA and ITCS accounts in November with a report filed by mid-January 1997, followed by an in-depth audit of the PITCO/POPCO account with a report filed March 1, 1997.

SoCalGas prefers ORA's original recommendation to hold the CFCA and ITCS accounts open for audit until 1999. If ORA's new proposal is adopted, SoCalGas requests the opportunity to review the auditor's report, file responsive testimony, and present its view in hearings on the issues, if necessary. SCUPP/IID is strongly supportive of ORA's proposal.

On August 28, 1996, the ALJ accepted ORA's proposal and set a procedural schedule for parties to file comments and requests for hearings four weeks after each report is filed. (Transcript at 2290-92.) We affirm that ruling.

VIII. California Alternate Rates for Energy (CARE) Program

A. Overview

Due to unexpected growth in CARE participation and related program costs, SoCalGas proposes three modifications to the current status of its CARE program and surcharge. Its proposal makes two modifications to program benefits to reduce costs and one modification to the allocation of the surcharge in order to partially alleviate the cost burden to its competitive market segment. The benefit modification consists of: (1) reducing the Service Establishment Charge (SEC) benefit from $20 to 15 percent of the current SEC of $25, which would equate to $3.75; and (2) eliminating the 15 percent discount on volumetric rates and the monthly customer charge, replacing it with a fixed discount for six months per year. To reduce the cost burden of the surcharge to its competitive market segment (G-30 or noncore customers), SoCalGas proposed to cap the volume of gas subject to the surcharge. SoCalGas recommends a cap of 250,000 therms per meter per year.

ORA and TURN oppose SoCalGas' proposal. ORA proposes maintaining the program as it exists today until Electric Restructuring dictates a new program design and funding mechanism. TURN also supports maintaining the current program, and proposes amortizing the forecasted undercollection of $29 million over the 31-month BCAP period, in order to reduce the rate impact. In addition, TURN asks the Commission to order SoCalGas to stop its practice of including the CARE surcharge as a line item on customer bills.

At hearing, witnesses from all three parties presented multitudes of ratios and percentages to support their positions. While the numerical analysis is interesting, the determination of what is too much cost or too little benefit remains subjective. We have reviewed all the evidence and must rely to a great extent on qualitative analysis. The analysis presented below relies on historical precedent, consistent with Commission decisions, and the evidence on record.

B. SEC Discount

SoCalGas' proposed modifications to CARE focus on SoCalGas' perceived need to reduce CARE costs. SoCalGas considers the current SEC discount to be the primary driver behind the high costs because the implementation of the SEC discount correlates with an increase in the growth rate of the program and a large undercollection in the CARE balancing account. SoCalGas presents data to support its conclusion both in this BCAP and in Advice Letter (AL) 2444 (filed September 22, 1995). In this proceeding, SoCalGas forecasts that the SEC discount will account for 17 percent ($7.4 million) of the program costs in 1997. SoCalGas argues that no other California utility has to pass an SEC subsidy of this magnitude on to its customers.

TURN and ORA testify that increasing the SEC will create greater hardship for the segment of the population that moves with the greatest frequency. TURN further argues that the SEC is only one of many costs when one moves. ORA states that absent evidence of a reduction in hardship for low-income customers in SoCalGas' territory, the benefit should not be reduced. Finally, ORA states that in AL-2444, SoCalGas attributes high enrollment to a large number of ineligible customers requesting CARE benefits; this should be corrected because Res. G-3182 authorized an up-front verification pilot study in response to AL-2444. Because the study is designed around the $20 SEC discount, ORA concludes that it would be imprudent to make changes before the pilot study is completed on December 1, 1997.

First, we should review the evidence in the record that compares SoCalGas' SEC discount to Universal Lifeline Telephone Service (ULTS) and other utilities' SECs, and consider the hardship and cost savings that would be created by SoCalGas' proposal. ULTS provides for a discounted SEC of $10.00 one time per year per customer (for Pacific Bell customers this amounts to a subsidy of $24.75.) For subsequent hook-ups, customers are required to pay the full rate.[15] Edison has a $10.00 SEC that all residential

15 Telephone companies are appealing to the Commission to remove the once per year condition from ULTS because they can not cost-effectively track the information necessary to know if a customer has already received the discount.

customers pay, SDG&E has an SEC of $15 per meter and no SEC discount, and PG&E does not have an SEC. Southwest Gas Company has a $25 SEC with no CARE discount but allows the cost to be split over more than one bill, and also covers full CARE costs under its PBR with no balancing account treatment. Also, SoCalGas customers with electric service from LADWP pay a $13 SEC for one meter and $2.50 for additional meters. Finally, customers must pay deposits for service to each service provider. SoCalGas states that utilities with low or no SEC are recovering service establishment costs through rates, and therefore, CARE customers are, at most, getting a 15 percent discount on the cost to establish service.

While SoCalGas correctly argues that CARE customers of other utilities pay SEC costs in their volumetric rate, SoCalGas fails to note that a large SEC can prevent customers from obtaining service. For a low-income customer who faces deposits and moving costs, the barrier to service is substantially reduced when the service establishment costs are included in the volumetric rates. Therefore, we conclude that increasing the SEC for CARE customers by $16.25, as SoCalGas has effectively proposed, will make the barrier to service for low-income customers unreasonably high.

We find a $5 SEC acceptable, but we observe that low-income customers in SoCalGas' territory may be accustomed to paying a $10.00 SEC, as the SECs for ULTS and Edison are set at this level. If we increase the CARE SEC to $10.00, SoCalGas will recover an additional $1.9 million (based on an estimated 373,000 SECs annually). This is a 25 percent reduction in the cost attributed to the SEC discount, but a 100 percent increase for CARE customers. Also, the discount for low-income customers should be available on every
hookup because limiting the discount to one time per year creates unnecessary hardship for low-income customers.

Finally, we address ORA's concern regarding Res. G-3182. Our conclusions regarding the SEC will go into effect with rates from the PBR decision. This will allow for completion of most of the pilot program.

C. Fixed Discount

SoCalGas' second benefit modification proposal changes the benefit from a 15 percent discount to a fixed monthly discount. SoCalGas supports its proposal by presenting evidence that most CARE customers will be better off under the fixed amount discount because the fixed amount will be equal to the average discount under the 15 percent discount program design. The average discount is greater than the median discount, therefore, most CARE customers will be better off. In addition, SoCalGas points out that this program design encourages conservation because the discount would be relatively greater as consumption decreases.

ORA testified that the program design should not be changed without full consideration of the alternatives which are being examined in the Electric Restructuring Low Income Working Group. ORA also states that the fixed amount, which today is equivalent to approximately 15 percent of an average CARE customer's bill, will be less meaningful as the customer charge rises in the future.[16]

Under current CARE guidelines established in D.89-09-044, CARE customers receive a 15 percent discount on both volumetric rates and the monthly customer charge. SoCalGas' bill impact estimates of its proposal show that the average CARE customer is almost equally well off with the fixed discount. SoCalGas' estimates are based on a 10 percent tier differential and decreasing rates. If these assumptions do not hold true, the benefit of the fixed discount to CARE customers would decline if there are rate increases (or smaller rate decreases than assumed),

16 ORA's data request #14, Table 1a.

and SoCalGas would incur greater costs if rate decreases are more than forecasted.

We acknowledge SoCalGas' argument that conservation is a worthy goal, but do not find it to be meaningful here. Since low-income customers on average have lower consumption than other customers according to the annual CARE report, and their consumption is likely to reflect poorly insulated homes and inefficient heating, hot water, and cooking appliances, reducing the CARE benefits may have little impact on consumption.

SoCalGas also recommends that the fixed amount be offered for only six months of the year, spanning the high consumption winter months. SoCalGas states that this will reduce hardship because winter is the most critical time for assistance. We point out that CARE was established to mitigate tier closure, and tier closure was enacted to mitigate high winter bills. Since winter and summer rates are tiered, it follows that CARE rates should be offered throughout the year.

Finally, we take into consideration ORA's position that the program should not be modified without full consideration of the alternatives for program design, now being exposed by the new Low-Income Governing Board established by D.97-02-014 (mimeo., p. 70). ORA points out that the Commission instructed the Governing Board to give full consideration to the gas industry as well as the electric industry, and while there is no set schedule for implementing changes, it is clear that the Commission's hopes to act during the BCAP cycle. While we find it appropriate to make short-term adjustments in this proceeding to alleviate problems, we find it inappropriate to modify the key elements of the CARE program such as program and surcharge design issues, when they are actively being considered in another proceeding.[17] Therefore, we will not alter the current 15 percent discount structure.

D. Capping

SoCalGas proposes capping the CARE surcharge to exempt all consumption on a single meter greater than 250,000 therms per year. SoCalGas believes that it is competitively disadvantaged in the gas industry because it must pass the high CARE costs on to G-30 customers, while other gas providers that are not regulated by the Commission are not subject to these costs. The CARE costs are recorded in a balancing account and the rate for the CARE surcharge is calculated to meet the forecasted status of the account.

The CARE balancing account currently reflects a large undercollection because of unexpected growth in participation and cost, and warm weather that affected all of the balancing accounts. Amortizing the current balance over a 12-month period increases the revenue collected through the surcharge from 1996 to 1997 by $7.36 million (69 percent) for the noncore, and $17.52 million (58 percent) for the core. The percentage increase is smaller for core because the total revenue generated by the core is greater. In fact, SoCalGas showed that the core pays 73 percent of the total CARE surcharge revenues and noncore pays only 27 percent.[18] By capping the surcharge responsibility of the largest consumers as SoCalGas proposed, the core portion of the surcharge revenue increases to 95 percent.

For a relative perspective, the following shows the contributions of each customer class toward the total surcharge for

17 SoCalGas testifies it is unique because it is a gas-only utility and, therefore, it should be treated separately from PG&E and SDG&E. However, with the proposed merger of Pacific Enterprises and Enova, SoCalGas' status has potentially changed.

18 Testimony of Patrick Petersilia, Exhibit 1, p. 23.

each of the major utilities. The table demonstrates that SoCalGas' noncore customers' contributions are within the range of large industrial and commercial customers of other utilities in the state.

Percentage of CARE Surcharge Paid by
Customer Class for California Utilities*

Electric	%
PG&E:	
Residential	32.9
Sm. Power	9.5
Med. Power	29.6
Lg. Power	23.1
Agricultural	4.9
SDG&E:	
Residential	35.2
Commercial	39.6
Industrial	23.7
Agricultural	1.5
Edison:	
Residential	30.2
Commercial	1.3
Industrial	42.3
Agricultural	18.3
Public Authority	8.0
Railroads	1.0

Gas	%
PG&E:	
Residential	43.5
GNR1	17.9
GNR2	1.1
GNR3	.05
Industrial	37.4
SDG&E:	
Residential	59.0
Commercial	22.0
Industrial	13.7
Transport.	5.3
SoCalGas:	
Residential	55.8
G-10 (core)	17.5
G-20 (core)	1.1
G-30 (noncore)	25.6

* All of the data presented above are from the annual CARE reports (May 1995 - April 1996) submitted to the Commission by the utilities, except for SoCalGas. SoCalGas' data are from this decision.

TURN proposes an alternative means to reducing the noncore rate impact. TURN recommends amortizing the forecasted balance of $29 million over the 31-month BCAP cycle and withholding interest on the accumulated balance, as an indication that SoCalGas should have come to the Commission earlier for emergency relief.

We find the 31-month amortization proposal preferable to the capping proposal to reduce the noncore cost burden for three reasons. First, in the short run, SoCalGas has not sufficiently demonstrated detriment to the noncore that justifies shifting costs to the core. The only example that SoCalGas could cite to support its argument of competitive disadvantage was bypass by enhanced oil recovery customers, who are exempt from the CARE surcharge. In the long run, SoCalGas has not convincingly shown that the core will be better off if the noncore gets this reduction.

Second, we believe that SoCalGas' growth rate of costs will decline over the course of the upfront verification pilot study (Res. G-1832) and that costs may actually decline, as up-front verification may reduce the level of participation.

Finally, the surcharge mechanism will be more thoroughly examined and modified in the Electric Restructuring proceeding to address competitive markets before this BCAP cycle closes. Therefore, the 31-month amortization will handle the high costs through this BCAP cycle and other forces will affect the size and allocation of the surcharge after that period.

We do not support TURN's position that SoCalGas requires a penalty for the undercollection. SoCalGas adequately notified the Commission of the program and cost growth through AL-2444.

B. Line Itemization

The last issue is TURN's recommendation that the Commission disallow the itemization of the CARE surcharge on customer bills. TURN claims that the Commission specifically ruled against this practice in the Electric Restructuring policy decision (D.95-12-063, modified by D.96-01-009, mimeo at 166). We do not agree. The manner in which the public goods surcharge will be identified on customers' bills has not been finally resolved (D.96-02-014, mimeo. at 76-77). In fact, in our electric restructuring policy decision, we stated:

> Our policy preference is to recover these low-income assistance costs as a surcharge on electricity use separate from other public goods charges....We establish this separate low-income assistance surcharge to provide a clear funding source for low-income programs." (D.95-12-963, mimeo. at 166)

Furthermore, we believe it is consistent with emerging competitive trends to separate surcharges for specific program funding from commodity charges. Therefore, until the generic issues have been addressed, we reject TURN's request and allow SoCalGas to follow existing CARE guidelines established in D.89-11-018 by itemizing the CARE surcharge on customer bills if it so chooses.

IX. Rate Design

A. Residential Rate Design

SoCalGas has proposed several rate design modifications for the residential class. These include:

-Monthly Customer Charge

-Tier Differential

-Baseline

SoCalGas is asking the Commission and parties to look at these proposals as a package instead of individual components. SoCalGas asserts that the package is revenue-neutral, although the individual components are not.

1. Monthly Customer Charge

SoCalGas proposes to phase in a significant increase in customer charges over the next five years. Currently, all residential customers pay a $5 per month customer charge. For single family and master-meter residential customers, SoCalGas proposes a customer charge of $7.12 per month, rising to $13.57 by Year 5. Multi-family customers would initially pay $5.26 per month, rising to $10.35 by Year 5.

SoCalGas asserts that high-volume customers currently subsidize low-volume customers because fixed customer-related costs are recovered in volumetric rates. When marginal customer costs exceed the customer charge, the excess will be picked up in volumetric rates. SoCalGas also concludes that customers in older homes are subsidizing customers in newer, more energy-efficient homes. SoCalGas proposes to reduce the subsidy by increasing the monthly customer charge and differentiating the customer charge by dwelling type.

ORA, TURN, and SOS oppose the proposal and seek to retain the current $5 customer charge. Both ORA and TURN claim that SoCalGas is using this proposal to reduce its throughput-related risk for collecting its revenue requirement under PBR.[20] ORA urges the Commission to refrain from considering SoCalGas' proposal until SoCalGas is candid about the risk.

TURN challenges SoCalGas' claim of a subsidy from large to small residential customers. First, TURN challenges SoCalGas' claim that the marginal customer cost is approximately $13.00 per customer per month. TURN shows that under its New Customer Only (NCO) proposal, the marginal customer cost is approximately $5.00 per customer per month. SoCalGas based its analysis on the rental method to calculate customer cost. Therefore, the five-year plan

20 Shifting the revenue requirement from volumetric rates to fixed charges provides greater assurance of the collection of the funds. TURN adds that SoCalGas' revenue recovery will be more weather sensitive under PBR and, therefore, SoCalGas wants to design rates for maximum stability.

to attain a $13.00 "cost-based" customer charge is valid only if Commission adopts SoCalGas' rental methodology.

Second, TURN questions that SoCalGas' assertion that the demand-related costs of serving all customers is equal in cents-per-therm. TURN provides its analysis showing that smaller residential customers have lower demand costs per therm than larger residential customers. TURN shows that weather-sensitive use increases as total use increases, and therefore, demand cost per therm is greater for large customers.

ORA states that rate design must include consideration of equity and SoCalGas' proposal is strictly based on economic efficiency. Equity dictates that the rate structure should allow customers to exercise some control over their bills, even if it means setting the customer charge below marginal cost. ORA also points out that the proposal has an adverse impact to low-income customers that would be mitigated for only six months of the year under SoCalGas' proposal. SOS points out that the Commission has historically viewed low-income customers as deserving Commission protection and SoCalGas' proposal would not meet that standard. The proposal is also particularly hard on low-income, low-usage customers that do not participate in the CARE program.

SOS challenges SoCalGas' claim that new homes subsidize old homes because they are more energy efficient. SoCalGas states that this is observable because consumption has declined on a per customer basis since 1983. SOS finds that SoCalGas' analysis does not include enough variables that affect consumption, such as conservation programs to improve the energy efficiency of homes, appliance replacement, weather, the price of gas, and possibly the size of newer homes. Also, SoCalGas has not sufficiently isolated the impact of the age of the home to make its claim. SOS testifies that 18 percent of housing stock was constructed after 1979. Thus, SoCalGas is essentially claiming that 18 percent of the customers are subsidizing 82 percent of the customers.

Further, SOS states that PU Code § 739.6 requires the Commission design rates that are consistent with policies of "affordability and conservation." SOS finds SoCalGas' proposal directly conflicts with this, as a lower customer charge and greater volumetric rate would promote conservation.

Finally, SOS points out that SoCalGas was authorized a large increase in the customer charge in the last BCAP, and to the extent that the customer charge sends a signal that there is a fee for safe, quality service, SOS finds that the increases are inequitable because the level of service has declined.

Discussion

We will reject SoCalGas' proposal at this time and retain the current customer charge. SoCalGas' analysis lacks evidence that a large subsidy exists for residential customers and that residential customers only pay a portion of their marginal cost in customer charges. We find the alternate analysis provided by TURN sufficient to question SoCalGas' claim.

Further, SoCalGas' argument that new homes subsidize old homes is inconclusive. If SoCalGas wants to use this argument in the future, it will need to present a comprehensive study isolating the effect of age of dwellings on gas consumption. We agree with SOS that variables were left out of SoCalGas' presentation, and data should be specific to SoCalGas' territory.

Regarding SOS' charges of reduced service, it does not provide evidence to support its claim. Although SOS states the areas in which it believes there has been a decline in service, the Commission requires a showing of evidence to demonstrate that the service has been inadequate.

Finally, to the extent that SoCalGas' proposal is related to minimizing risk, it should be directly addressed in the PBR proceeding.

2. Tier Differential

SoCalGas proposes to reduce the residential tier differential to approximately 10 percent. It claims this will provide cost-based signals. The rate impact of SoCalGas' proposal is an increase of 2.4 percent for tier 1 and a decrease of 16.5 percent for tier 2. SoCalGas anticipates this rate design will cause tier 1 consumption to decrease and tier 2 consumption to increase.

ORA, TURN, and SOS oppose the proposal. Some of their reasons for opposing the increased customer charge also apply to tier closure because both proposals reallocate costs from large consumers to smaller consumers. These positions address conservation, control over bills, and equity. Currently, the higher tier 2 rate encourages conservation, and curtailing usage in the tier 2 range has a greater impact on the bill than curtailing tier 1 usage. Under SoCalGas' proposal to close the tier differential, the incentive to reduce tier 2 consumption would decline, as conservation would have less impact on the bill. The opposing parties point out that SoCalGas is in line with the current differentials of other gas providers, and the differentials for gas have been consistently greater than the differentials for electric rates. The parties find it inequitable that customers who consume primarily tier 1 gas will see greater increases than the remainder of the class.

ORA claims SoCalGas' proposal favors economic efficiency over equitable movement toward cost-based rates. ORA's proposal to leave the current rate design unchanged meets the criteria of inverted rates and the composite tier differential. The current 35 percent differential is a consistent price signal that tier 2 gas is more expensive than tier 1 gas.

TURN proposes a 20 percent composite tier differential and states that there is currently only a 3.9 percent composite tier differential which leaves no room for change in the direction of SoCalGas' proposal. TURN States that the only exception to the composite tier differential was D.94-12-052, and TURN has pending a petition to modify that decision.

SOS stresses that consumers whose total usage is at tier 1 have less ability to control their usage as there is less consumption to curtail. To the extent low usage is reflective of low income, the proposal is inequitable because these customers will be paying higher rates and conceivably have expenses such as insulation and other conservation measures. Meanwhile, tier 2 consumers are given a price signal to increase consumption. Even though low-income customers are associated with less efficient homes, their consumption is consistently less on average than higher income customers, presumably in more efficient homes.[21]

SoCalGas has not provided sufficient justification for its proposal. While the gas differential may be higher than the electric differential, we find this reasonable given that gas consumption tends to be for only the most basic needs, i.e. heating, hot water, and cooking. We find it crucial to keep price signals that indicate that basic necessities should be affordable, and additional consumption will cost more. SoCalGas' proposal gives the perverse signal that tier 1 users should be more conservative and tier 2 users less conservative.

Therefore, we should retain the existing tier differential calculated on a composite basis. The composite tier differential is more meaningful than the simple differential because it gives the price for access and purchase of a quantity of gas that covers basic needs.

21 See annual CARE report.

3. Baseline

SoCalGas proposes to reduce its summer and winter baseline quantities. SoCalGas has three baseline zones, of which Zone 1 is the largest. The proposed revisions are:

	Current	Proposal
	(in therms)	
Zone 1-Summer	16*	14
Winter	50	46
Zone 2-Summer	16	14
Winter	65	59
Zone 3-Summer	16	14
Winter	87	79

* During the preceding, SoCalGas realized that the current baseline quantity of 16 therms is above the established range of 50-60 percent. To bring SoCalGas within the guidelines, the quantity would have to be reduced to 15 therms.

Currently, 60.8 percent of residential summer throughput is billed at the baseline rate. Under SoCalGas' proposal, 56 percent of residential summer throughput would be billed at the baseline rate. The current winter throughput at the baseline rate is 69.1 percent, and under the proposal it would be 66 percent.

SoCalGas cites PU Code § 739(d)(1) to justify its proposal. This section states "the Commission shall review and revise baseline quantities as average consumption patterns change." SoCalGas points to a long-term downward trend in the average use per residential meter and, therefore, states the downward shift would prevent the need for multiple adjustments in the future.

ORA, TURN, and SOS oppose the proposal and want to retain the current quantities or at most reduce the summer quantity to 15 therms to bring SoCalGas into compliance with the statute. These parties find SoCalGas fails to present sufficient evidence to support the proposed downward shifts.

SoCalGas shows a downward trend in residential consumption through 1994; however, this trend showed a substantial anomaly from May 1994 through April 1995. In data that SoCalGas submits to the Commission in its annual CARE reports, SoCalGas showed gradually declining consumption from May 1990 through April 1994, but a large increase in residential consumption for nonCARE customers as well as CARE customers in SoCalGas' Sixth Annual Report, covering May 1994 through April 1995. Commission staff specifically inquired about the accuracy of the data at the time SoCalGas' report was reviewed and SoCalGas confirmed that the data were correct. Therefore, there is reason to refrain from making changes based on the forecasted continuation of the downward trend. SoCalGas has not provided justification for its recommended change in baseline quantities.

Based on the above discussion, we find SoCalGas should reduce its summer baseline quantity to 15 therms to comply with statutory guidelines; however, winter baseline quantities should remain unchanged.

4. Core Deaveraging

In this BCAP, SoCalGas proposes to entirely eliminate core averaging. In its last BCAP, the Commission authorized full deaveraging of the G-20 class, and partial deaveraging of the G-10 class. SoCalGas proposes its changes based on the objective of cost-based pricing. SoCalGas states that the G-10 class currently subsidizes the residential class by $77 million per year.

ORA, TURN, and SOS oppose the proposal. They strongly assert that SoCalGas must provide the study on customer classification, as ordered in the LRMC decision, prior to any further deaveraging. Currently, customer classification determines which customers' rates are averaged together. TURN states that "within the residential and commercial end use categories there can be a wide range of different cost incurrence patterns." (TURN Testimony, Florio, p.24) Testimony from two large residential customers, E&S Ring Management, and PLB Management, supports TURN's position. Furthermore, TURN and ORA state that the amount that would be deaveraged depends on LRMC methodology, for which they have proposed alternatives to SoCalGas' current methodology. Under TURN's NCO proposal, approximately $56 million would be deaveraged as opposed to SoCalGas' figure of $77 million.

ORA suggests there could be an incentive mechanism whereby SoCalGas may annually take steps toward deaveraging as the core revenue requirement is reduced. ORA states that SoCalGas' package of proposals would shift $191 million to the residential class, and that the study ordered by the LRMC decision must be provided before this is allowed.

TURN states that alternative methods of analysis include examination of demand characteristics (comparative elasticities) and value of peak service reliability. In addition, rate options should increase as a new metering technologies are introduced and residential customers need to be included in the service options.

Consistent with our policy articulated in D.94-12-052 to gradually eliminate the cross-subsidies in the G-10 rate, we will deaverage approximately 50 percent of the remaining subsidy, as it will enable us to correct another rate design issue in the G-10 class. We will not allow further deaveraging at this time because we are not certain what costs truly are attributable to the residential class, nor are we confident that the residential class fits the definition it is currently assigned as demonstrated by the two large residential intervenors in this proceeding. We will direct the Executive Director to ensure staff include the issue of the remaining deaveraging and a potential customer classification study in the procedural roadmap that we expect to follow our Natural Gas Strategy.

Therefore, we should further deaverage core rates 50 percent in this proceeding.

5. Residential Segmentation

PLB Management, LLC (PLB) and E&S Ring Management Corporation (E&S) testified in this proceeding seeking rate relief as large residential customers. The companies own and operate large apartment complexes in SoCalGas' service territory. Both companies have properties that consume well over 250,000 therms per year, the demarcation for noncore status. However, Commission rules preclude residential customers from choosing noncore status because residential customers are reserved the highest level of priority on the transportation system. Core Aggregation Transportation (CAT) is the only alternative to the utilities' residential rates, but it does not provide the magnitude of savings that noncore rates provide.

E&S is already receiving gas under the CAT program. E&S seeks noncore status and is sponsored by Enron, who states that customers of its size should be able to determine the level of reliability that they are willing to accept. E&S testifies that its gas usage is for swimming pools, jacuzzis, hot water and some cooking; its properties do not use gas for space heating; thus, some risk of reliability is acceptable.

PLB seeks a new rate category for large residential customers within the core class. PLB's proposal addresses the cross subsidy that occurs from large to small residential customers when we adopt SoCalGas' proposed marginal customer cost. Under SoCalGas' marginal customer cost scenario, marginal customer costs that are not picked up by the monthly customer charge are included in the volumetric rate for gas. Under PLB's proposal, residential customers consuming greater than 250,000 therms per year would pay the customer-related costs based on SoCalGas' marginal customer cost proposal of approximately $7,600 per year, and a volumetric rate that would not include any other customer-related charges. The remaining residential revenue requirement would be allocated among the rest of the residential class. It is unclear if PLB is participating in CAT. PLB wants to retain its same level of service and reliability.

Both PLB and E&S state the savings realized under their proposals would not be passed on to the tenants. PLB states that savings would go into the general budget for operations. E&S hopes to recover some of its losses from the recession of the past five years in Southern California.

ORA opposes E&S' proposal, stating that its residential customers do not have an alternate fuel source if they were curtailed and, therefore, the proposal is unacceptable. ORA's opposition is also based on the fact that the tenants may not see any of the savings that the company would receive. ORA did not comment on PLB.

Discussion

These proposals raise three issues. First, E&S is seeking noncore status without regard for reliability. This is unacceptable. The Commission cannot place residents at risk of less reliable service. The residents are not selecting to put themselves at risk and they would not benefit from the risk because E&S would retain the savings. Second, as discussed in the previous section, SoCalGas has yet to present the customer classification study that would allow us to consider redefining the residential customer classes. Finally, depending on the results of the customer classification study, the Commission may need to address the rate impacts of substantial core migration and ensure remaining residential customers are assured adequate service at reasonable rates.

Therefore, we should not adopt E&S's proposal in this proceeding. We recognize their concerns and should revisit the issue in our Natural Gas Strategy proceeding.

PLB raises an issue we can address in this proceeding. We have consistently recognized the importance of providing accurate price signals, and pricing based on the principle of cost causation. PLB's proposal suggests a method of unbundling residential rates to provide rates more closely alligned with costs. It is impractical to unbundle costs down to the individual residential customer level. However, PLB's suggestion of 250,000 therms per year is a reasonable point of delineation as this is our current floor for core aggregation.

PLB's suggested method for unbundling customer-related costs would not affect the customer charge paid by each smaller residential customer, but would instead reduce the volumetric rate for customers like PLB. PLB's volumetric rate would be reduced by the amount of customer-related costs in that rate which are above its average customer-related costs. Using SoCalGas' marginal customer cost proposal, this reduces the average amount of customer costs paid by these customers to approximately $7628 per year compared to PLB's current combined rate of about $366,000 per year. This proposal would have a minor impact on other residential customers by increasing their volumetric charges by less than $1 per year. We are most sensitive to the rates borne by low-income customers, but note that the rate increase to these customers would be negligible (averaging $.013 per year to multifamily low income households). On balance, the improved cost signals and more accurate pricing methodology outweigh the negative impacts on small customers. We will adopt PLB's proposal.

B. Core Commercial/Industrial

SoCalGas proposes to combine the G-10 and G-20 classes to create a seamless rate design. All customers in the class would be charged a monthly customer charge of $15.00. The rate structure would be declining block in order to prevent large customers from subsidizing small customers. The proposal is linked to the core deaveraging proposal to the extent that G-20 customers might end up subsidizing residential customers again if there continues to be a G-10/residential subsidy, and G-10 and G-20 classes are merged.

Currently, G-20 customers pay a $350 monthly customer charge, and G-10 customers pay a $15 monthly customer charge. The current rate structures create an anomaly in which large G-10 customers can pay a higher bill than small G-20 customers for less consumption and equal reliability. SoCalGas' proposal removes this anomaly so the bill increases as consumption increases.

ORA opposes SoCalGas' proposal because it depends on the core deaveraging proposal, which ORA opposes.

We agree with SoCalGas that the rate structure should be redesigned to eliminate the overlap between G-10 and G-20 rates. However, we do not accept the remainder of SoCalGas' proposal. We do not see the justification for reducing the G-20 customer charge to $15, when SoCalGas has argued that customer charges should reflect marginal customer costs. This issue could be reconsidered after the customer classification study is completed and we have more confidence in the marginal customer costs. Instead, we have retained the two separate customer classes and customer charges, and have adjusted rates to eliminate the overlap without allowing rates for other customer classes to increase as a result of this particular adjustment.

C. Master-meter Customers

SoCalGas currently pays a credit to its master-meter customers to compensate them for the costs of providing submeter services because submetering avoids costs to SoCalGas' system. The methodology to calculate the credit was established in D.90-11-023. SoCalGas proposes to update the methodology, basing the credit on the marginal cost of the submeter systems. Its proposal increases the credit from $1.36 to $3.02. The increase also accounts for the increase in the customer charge.

ORA and WMA respond to SoCalGas' proposal. ORA does not oppose SoCalGas' proposal, but points out that the actual credit amount depends on the final cost allocation and rate design, and should be adjusted accordingly.

WMA proposes to modify SoCalGas' calculation to use costs that are specific to mobilehome parks. WMA points out that the marginal costs that SoCalGas uses are the average costs for all submeter customers. WMA states the the distribution costs for mobilehome parks are significantly higher because they have distribution mains and longer line lengths. WMA states that the higher costs are not represented by the marginal costs that SoCalGas used because only one percent of the submeter customers are in mobilehome parks. WMA adds that the other major gas and electric utilities in California have separate submeter credits for mobilehome parks and multi-unit housing due to the differences in distribution costs.

WMA demonstrates that the inclusion of distribution mains would increase the annual avoided submeter cost by $34.03. WMA requests the Commission to adopt WMA's method for calculating the submeter credit on an interim basis, and order SoCalGas to perform a complete study of mobilehome park submeter avoided costs for the next BCAP.

SoCalGas responds that it does not oppose WMA's proposal, but the proposal cannot be justified under the current LRMC methodology. SoCalGas states that the solution would be to revise the current methodology in order to treat distribution costs as customer-related costs.

We accept WMA's proposal to include the cost of distribution mains as presented in its testimony. However, we will not order SoCalGas to perform a study specifically on the submeter costs. We believe this issue can be appropriately addressed in any study of customer classifications which we will consider as part of the roadmap following our Natural Gas Strategy. As a result, we adopt WMA's proposal as a final rate.

D. Residual Load Service (RLS) Tariff

1. Background

In D.95-07-046, the Commission approved a modified SoCalGas proposal to implement a load-specific flexible rate design for noncore customers who choose to partially bypass SoCalGas' transportation system. This design is known as the Residual Load Service (RLS) tariff.

The RLS was implemented in order to close a regulatory gap which would have unfairly rewarded noncore customers for partially bypassing SoCalGas. This gap arises because SoCalGas, due to utility franchise rights, is required to serve all customer load within its service territory. Without the RLS, other gas transportation providers would have been able to contract with SoCalGas' noncore customers to provide their base loads at lower, negotiated rates and leave SoCalGas obligated to serve those customers' high-cost peaking loads at tariffed rate. The losses resulting from this loss of noncore base load, combined with the requirement to serve high cost residual load at tariffed rates, would have been borne by SoCalGas' shareholders and remaining captive customers. The RLS was implemented to ensure that noncore customers' costs of partially bypassing SoCalGas internalize the externalities that their bypass places on the general body of ratepayers (D.95-07-046 slip op. at 15).

Under the RLS, SoCalGas is allowed to negotiate rates for gas transportation with each noncore customer who decides to bypass. Rates must be negotiated between a floor equal to SoCalGas' short-run marginal cost and a default ceiling rate equal to the product of the current tariff and the ratio of the customer's load factor before bypass to the load factor after bypass.[22] (Id. at 13.) The RLS does not apply to off-spec gas, refinery produced gas or gas produced and consumed within the service area of a wholesale consumer. (Id. at 17.) The RLS was approved for an interim period, until implementation of the instant BCAP.

Since its implementation, no noncore customer has partially bypassed SoCalGas' service. Consequently, the RLS tariff has never been used.

Both Edison and SCUPP/IID advocate the elimination of the RLS in these proceedings. SoCalGas argues for its maintenance with minor modification.

In support of the proposed elimination of the RLS, Edison argues that the RLS tariff: (1) is unfair because it is not cost-based; (2) discriminates against multi-unit electric utilities; and (3) discourages economic bypass.

Edison states that with the exception of Hub Service, the "RLS tariff is the only transmission service tariff for noncore customers that is not cost-based." (Edison Opening Brief at 45.) Edison argues that since many of its generating stations have no practical alternative to SoCalGas, SoCalGas should not be allowed to charge a market-based rate, but instead only one which is cost-based.

Second, Edison submits that the RLS tariff discriminates against multi-unit electric utilities in favor of single-unit power producers. Edison supports this allegation by noting that if it were to accept a bypass offer "at one of its generating stations,

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22 RLS Default/Cap Rate = T*La/Lp

Where:

T = the tariff rate
La = the customer's load factor before bypass
Lp = the customer's load factor after bypass

Edison would pay the RLS rate for all transportation it takes from SoCalGas at all of its generating stations." (Id. at 46.) Edison notes that a single-unit producer would pay the RLS rate only at the station which accepted the bypass offer.

Finally, Edison claims that the RLS tariff discourages economic bypass, even in cases where the bypass offer is lower than SoCalGas' marginal cost. Edison has provided testimony allegedly showing this to be true under a hypothetical scenario. (Exhibit 77, Attachment A.)

SCUPP/IID advocates elimination of the RLS because (1) it is unnecessary; (2) the direct threat of pipeline bypass has significantly diminished; (3) it may actually promote total bypass; and (4) it does not address by bypass-by-wire issue.

SCUPP/IID claims that the RLS is unnecessary because there are no existing bypass pipeline threats to SoCalGas. SCUPP points to the withdrawal at the FERC of the application of the Mojave Northward expansion and SoCalGas' purchase of the Cuyama-Casitas pipeline from ARCO as evidence of the diminished threat to SoCalGas of bypass since the RLS was implemented. (SCUPP/IID Opening Brief at 40.)

SCUPP further asserts that the RLS should be eliminated because it promotes total bypass by imposing a penalty on partial bypass customers. SCUPP maintains that the only sensible economic decision in the face of the RLS is to bypass completely rather than pay the high RLS rate on residual loads.

Finally, SCUPP/IID argues that the RLS does nothing to reduce the threat of bypass by wire and that it may in fact exacerbate the problem by discouraging otherwise economic partial bypass.

SoCalGas argues that the RLS should be maintained with minor modification. SoCalGas disagrees with SCUPP/IID's assertion that the threat of pipeline bypass has been significantly diminished. SoCalGas claims that the RLS "effectively negates a regulatory-induced competitive disadvantage that existed previously." (Opening Brief at 123.) Furthermore, it contends that the RLS "sends the appropriate signal to the marketplace by clarifying that the utility will not be left in the position of subsidizing potential bypass projects, but will be allowed flexibility to compete to retain contestable load." (Id. at 122.)

SoCalGas requests two modifications to the RLS. Because Edison has not published gas load factors in its Energy Cost Adjustment Clause (ECAC) proceeding, SoCalGas states these figures are unavailable to calculate of the RLS tariff rate in the case of partial bypass. As an alternative method, SoCalGas suggests the following formulas for the calculation of load factors for Commission jurisdictional customers:

$$\text{Pre-Bypass Load Factor} = \frac{\text{(SoCalGas Daily Deliveries + Bypass Daily Deliveries)}}{\text{(SoCalGas Daily Deliveries + Bypass Peak Day Deliveries)}}$$

$$\text{Post-Bypass Load Factor} = \frac{\text{(SoCalGas Daily Deliveries)}}{\text{(SoCalGas Peak Day Deliveries)}}$$

For nonjurisdictional customers, who cannot be compelled to reveal their load data to the Commission, SoCalGas suggests calculating the pre-bypass load factor by averaging the customer's loads over the four preceding years and fixing that average load factor for the duration of the BCAP period.

Neither Edison nor SCUPP/IID commented on SoCalGas' proposed changes.

2. Discussion

In D.95-07-046, we engaged in a full discussion of the rationale behind the RLS tariff. We will not repeat that discussion here.

Edison has provided few arguments against the RLS tariff that it did not raise in the original proceedings. Then as now, Edison argues that the RLS tariff is objectionable because it is not cost-based. Edison complains that, because it has "no practical market alternative to SoCalGas for many generating stations, SoCalGas should not be allowed to charge a market rate." (Edison Opening Brief at 45.) We considered and rejected this argument before, noting that no customer is ever forced to accept the RLS tariff. Because the RLS tariff is not applicable unless and until a customer voluntarily bypasses SoCalGas, the customer has "the clear option of SoCalGas' service under cost-based rates." (D.95-07-046, slip op. at 12.)

In addition, Edison argues now as before that the RLS discriminates against multi-unit electric utilities. It bases this conclusion on the fact that the RLS tariff would apply to all facilities of a customer which bypasses SoCalGas, not only the bypassing facility. For example, if Edison were presented with and accepted an offer from a bypass pipeline at one of its generating stations, Edison would pay the RLS rate for all transportation it takes from SoCalGas at all of its generating stations. In contrast, for a nonelectric utility generator, such as an Independent Power Producer (IPP), the RLS tariff applies only at the generating unit that partially bypasses SoCalGas. If the IPP owned the same generating unit as described above, instead of Edison, and was presented with the same offer from a bypass pipeline, the IPP would only pay the RLS rate for transportation that it takes from SoCalGas at the potential bypass generating station. Therefore, the bypass economics of the RLS tariff unfairly differ, solely because of the ownership of the generating station. (Edison Opening Brief at 46.)

Edison fails to consider in its analysis that the RLS tariff is essentially a multiplier based on the change in a customer's system-wide load after bypass. The greater the decline in load factor after bypass, the greater the rate paid for residual SoCalGas transportation. This characteristic of the RLS tariff makes it entirely neutral to the number of generating units operated by the customer.

Edison correctly notes that all of its stations would pay the RLS tariff for transportation from SoCalGas if even one unit bypassed. However, the default RLS tariff rate multiplier would be relatively small since there would be a relatively minor variance in Edison's company-wide load factor measured before and after bypass. In contrast, the stand-alone IPP in Edison's hypothetical would pay the RLS tariff rate on only the SoCalGas gas transportation utilized by the one plant, but the RLS rate would be relatively high due to the large change in load factors before and after bypass. Because the RLS multiplier is applied company-wide, based on company-wide load factors, all customers are treated identically, regardless of the number of generating units they operate.

Contrary to Edison's argument, we have found that "facility-by-facility treatment of UEG customers would serve to encourage uneconomic bypass." (D.95-07-046, slip op. at 20.) Because multi-unit UEGs can dispatch on an integrated system basis, they have the ability to potentially bypass entirely at some generating stations and maintain service from SoCalGas at others. By switching peak load generation to the SoCalGas-served stations, a multi-unit generator could completely avoid the RLS if it was applied separately to each facility. This would encourage the customer to bypass at some stations, relying on the SoCalGas for high-cost residual load service at tariffed rates at its other stations. This is precisely the type of outcome the RLS tariff was instituted to discourage.

Finally, we reject Edison's argument that the RLS tariff discourages economic bypass since it may cause a multi-unit generating utility to reject a bypass offer at rates lower than SoCalGas' marginal cost. Edison focuses only on short-run marginal costs. Although it may be true that a bypass offer below SoCalGas' short-run marginal cost might be rejected by Edison due to the impact of the RLS tariff, this does not show that the RLS tariff discourages economic bypass. Edison fails to consider SoCalGas' long-run costs associated with customer service. "SoCalGas incurred these costs in building the system with the expectation of full service and without the expectation of bypass." (D.95-07-046, slip op. at 12.) We implemented the RLS tariff in order to allow SoCalGas the opportunity to recover these costs. "Under this rate cap, the customer will pay at most the full cost which it imposes on SoCalGas' system by its partial bypass." (Id. at 13.) Without the RLS tariff, partial bypass would be encouraged, ignoring SoCalGas' long-run costs. Contrary to Edison's argument, when both short- and long-run costs are considered in determining what is and what is not "economic," the RLS tariff does not discourage truly economic bypass.

SCUPP/IID's arguments against the RLS are not persuasive. SCUPP/IID first argues that the RLS tariff is unnecessary because there is no imminent threat of bypass in SoCalGas' service area. We find no compelling reason to dismantle the RLS merely because it has not yet been utilized. In implementing the RLS tariff, we found that "decisions to bypass, whether partial or total, should be done with full knowledge of the prospective cost of bypass." (Id. at 14.) Elimination of the RLS until actual bypass occurs would be misleading. Alternatively, maintaining the RLS gives the correct price signals to consumers and potential bypass pipelines.

Second, SCUPP/IID maintains that the RLS tariff will encourage total rather than partial bypass. SCUPP/IID fails to consider that the RLS tariff allows for negotiation of rates between a floor rate (SoCalGas' short-run marginal cost) and the default ceiling rate based on load factor after bypass. Given the threat of complete bypass, SoCalGas, acting in its own self-interest, will undoubtedly seek to maintain load by negotiating a rate somewhere within the RLS range. This flexibility ensures that the RLS will not encourage full over partial bypass.

Finally, we are unpersuaded by SCUPP/IID's argument that the RLS tariff should be eliminated because it does not address the issue of "bypass-by-wire." It does not logically follow that the RLS should be rescinded merely because it is not comprehensive in its response to every potential competitive threat.

3. Modifications to the RLS Tariff

SoCalGas has requested changes to the method for calculating the pre- and post-bypass load factors for the purpose of calculating the default RLS tariff rate. These changes appear equitable and necessary in order to allow the RLS tariff to function as intended. No parties opposed these changes. We will therefore approve them.

In summary, the RLS tariff continues to be required in order to discourage bypass which would leave SoCalGas providing high-cost peak rate service at low tariffed rates to customers who partially bypass. Without the RLS tariff, SoCalGas' class average volumetric rate structure would provided "poor price signals to noncore customers and may promote uneconomic bypass by providing an underpriced insurance policy to customers with market alternatives." (Id. at 20, Finding of Fact 4.) The RLS does not discriminate against multi-unit generators. We conclude that the RLS tariff implemented in D.95-07-046, as amended by this decision, should remain in effect.

E. Rate Cap

TURN testifies that the Commission has consistently held that adverse customer impacts are not a valid basis for rejecting otherwise appropriate changes in costing methods. Rather, the traditional remedy, routinely applied in electric ratemaking, has been to apply percentage caps to the rate changes that would otherwise result from moving rates directly to EPMC.

TURN recommends a noncore retail rate cap of 20% which, if viewed against the backdrop of the 36% decrease this customer class received as a result of LRMC implementation in D.93-05-066, would effectively limit the earlier noncore retail decrease to 23.2%. TURN recommends a wholesale rate cap of 12.5% because these customers received only a 6.25% reduction from initial LRMC implementation. (Exhibit 68, p.18-19.)

We find TURN's proposal reasonable and will adopt it. TURN states its recommendation addresses only a small component of the noncore customers' cost of natural gas service, the cost of intrastate transportation; therefore, we should apply the cap to noncore transportation rate without the ITCS component.

While we find adoption of a rate cap proposal reasonable in this proceeding, we expect further movement toward full EPMC in all future annual rate adjustments.

SDG&E - A.96-04-030

X. LRMC Methodology

A. Gas Resource Plan

1. SDG&E's Proposal

SDG&E includes in Chapter XI of its 1996 BCAP application its gas resource plan. As addressed in our discussion of SoCalGas' resource plan, SDG&E did not request, nor has it been granted, authority to deviate from the filing requirements of D.92-12-058 which require it to file its resource plan in a general rate case proceeding, not a BCAP, so that the Commission and interested parties will have sufficient time and resources to adequately review the issue.

SDG&E states that its resource plan complies with the Commission's directives and reflects the appropriate planned system that meets customers' needs at the lowest total cost for its explicit design objectives for core and noncore customers that it has used to calculate the long-run marginal local transmission costs.

SDG&E's reliability objective is to provide service to core gas customers on a 1-in-35-year abnormal peak day (APD). According to SDG&E, this APD criterion has a 3% chance of occurring in any given year. It states that the APD condition correlates to an average daily temperature of 42 degree Fahrenheit or 23 heating degree day and that the 1-in-35-year APD criterion minimizes total costs and effectively balances the trade-off between customer's value of service and the cost of providing reliability.

SDG&E provides an implicit 1-in-5-year reliability level for noncore customers. It states that it does not guarantee any specific noncore reliability level, but firm noncore customer can expect an interruptible service equivalent to one in 5-year reliability level.

In its application, SDG&E states that its planning horizon is 15 years, from 1997 to 2011. It forecasts core APD demand to grow at an annual rate of 1.4% over the planning horizon based on its forecast of future annual core throughput and APD weather conditions. SDG&E projects its APD gas demand will grow from 424 MMcf/d in 1997 to 515 MMcf/d by 2011 and plans to meet this growth through three expansion projects at a cost of $27.3 million. SDG&E assumes that SoCalGas will complete phases 3 and 2 of SoCalGas' Line 6900 pipeline between Moreno and Rainbow by 2004 and 2010, respectively.

ORA asserts that SDG&E's resource plan does not minimize costs to core ratepayers but instead provides inexpensive reliable service to noncore customers under the guise of meeting core reliability standards. ORA states that SDG&E misses the purpose of a natural gas resource plan, which is clearly stated in D.92-12-058, by claiming there is no linkage between this plan and cost allocation and testifying that it gave "very little to no consideration" to the price impact on its customers when developing its plan (Tr. p. 2641).

In its testimony, ORA includes years 1995 and 1996 as part of its 15-year resource planning horizon for (1) consistency with the projected period used by SDG&E for its distribution system; and (2) consistency with SoCalGas' inclusion of 1995 and 1996 in its transmission marginal cost computation. (Exhibit 217, pp. 9-14.) Based on this, ORA calculates $56.3 million in transmission capital investments. While ORA does not take exception with specific projects proposed by SDG&E, it does object to the plan being used in LRMC methodology for cost allocation purposes because it does not properly allocate the costs of the plan to the customer classes who benefit from the investments. ORA testifies that SDG&E's resource plan reduces curtailment risk for all of SDG&E's noncore customers at the expense of core customers.

ORA concludes that SDG&E's resource plan does not meet the standards set by the Commission and, therefore, recommends that the Commission reject it and order SDG&E to update its plan to reflect all the factors required by D.92-12-058. The deficiencies in SDG&E's plan cited by ORA are:

1. It failed to provide a plan reflecting the core service reliability studies ordered in D.92-12-058 and instead chose to perform sensitivity analyses of value of service studies performed by SoCalGas and PG&E, even though the PG&E study was deemed flawed by the Commission.

2. It did not identify an explicit reliability objective for its noncore customers, as required by D.92-12-058. It uses an "implicit" one-in-five year noncore reliability criterion while the record shows that noncore customers have been interrupted only once in the last ten years and that that interruption appeared partly related to cold weather in Southwestern supply basins, not just cold weather in SDG&E's service territory.

3. It did not follow the logical sequence of LRMC methodology: "first, customer demand is forecast; second, a resource plan is

> developed to meet this demand at the lowest possible cost; third, the costs of this system are allocated to customers using Commission approved cost allocation factors; fourth, and finally, rates are calculated that will collect the costs of the system from utility customers in a just and reasonable manner." (Opening Brief, pp. 3-4.)

Discussion

We agree with ORA that SDG&E has not followed Commission directives in its resource plan by providing an explicit noncore reliability standard and a core service reliability study that documents the value its core customers place on peak service reliability.

We are particularly concerned that SDG&E does not believe that "least-cost" is to be evaluated in terms of the prices paid by its customers and that it does not believe its noncore customers should be responsible for any transmission costs on its system. In its reply brief, SDG&E states, "The fact that any transmission costs are allocated to the noncore represents a subsidy from noncore to core customers" (Id., p. 4.)

We are also concerned with the accuracy of SDG&E's long-term demand forecast, the foundation of its resource plan. The magnitude of change that has occurred in SDG&E's long-term forecasts since its last BCAP needs to be further reviewed. As we discussed earlier for SoCalGas, the schedule of a normal BCAP is not sufficient to adequately review the long-term demand forecasts and other components of the resource plan.

In its rebuttal testimony, SDG&E includes a data request response that states:

> "The gas resource plan used to develop long-run marginal in SDG&E's last BCAP was developed in 1991 and was the same plan submitted in the Long-Run Marginal Cost Proceeding. This plan

identified $79.1 (1993$) million in future resource additions over a 20-year planning horizon." (Exhibit 203, Appendix A to Chapter VII.)

In this proceeding, two years later, SDG&E submits a long-term resource plan which, when extended to a 20-year comparable planning horizon, totals $29.8 million, a 38% reduction. Since its last BCAP, SDG&E has also dropped its long-term demand forecast 26%.[23]

In adopting LRMC methodology in D.92-12-058, we expected it would provide a much greater degree of stability than short-term marginal cost methodologies. SDG&E's proposal, as well as SoCalGas' discussed previously, causes us to question the validity of our underlying assumption.

Rather than requiring SDG&E to refile its entire resource plan, we should instead direct it to provide the missing elements. SDG&E should provide a core reliability study based on a survey of its customers and this survey should include consideration of tariff offerings for peak/off-peak pricing and voluntary load reduction programs.

SDG&E should propose an explicit noncore reliability standard for its firm service transportation customers that reflects the level of service its system is able to provide. SDG&E should discuss the engineering design criteria it uses in assessing whether it can meet its forecasted firm noncore load under (1) APD; (2) cool year peak day; (3) cold year coincident peak month demand; (4) cold year winter season demand; and (5) average year demand.

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23 SDG&E projected its annual growth rate in the last BCAP at 1.9%, or from 415 MMcf/d in 1991 to 591 MMcf/d in 2010, while in this BCAP, for a comparable 20-year horizon, SDG&E projects annual growth at 1.4%, from 424 MMcf/d in 1997 to 550 MMcf/d in 2016. (Ex. 203, Chapter VII.)

We direct SDG&E to perform the above studies using the long-term demand forecast it developed for this proceeding. This will allow other parties to further investigate its underlying demand forecast while SDG&E is preparing its reliability studies.

The Commission's resources cannot readily accommodate the need to address the deficiencies of SDG&E's application. SDG&E should file its completed plan within six months of this order. Parties will have 60 days following the filing to review the additional information prior to a discussion of the procedural schedule that will be necessary to complete our review of SDG&E's resource plan. Therefore, a prehearing conference will be scheduled 60 days after SDG&E's filing. To the extent the Commission has reached a decision on SoCalGas' Line 6900 that affects SDG&E's proceeding, this issue can also be addressed at the PHC.

On an interim basis, we can either retain SDG&E's adopted resource plan or adopt an interim proposal. ORA uses in its calculations SDG&E's resource plan beginning in 1995; SDG&E uses a beginning date of 1997. SoCalGas' cross-examination of SCUPP/IID witness Burkholder establishes that SDG&E's proposal to use a beginning date of 1997 is a deviation from existing methodology (Transcript, Vol. 16, p. 1855). We find ORA's rationale for its proposal persuasive and, therefore, adopt its calculation of a $56.3 million resource plan; this could later be modified based on SDG&E's completed filing.

As we stated in our discussion of SoCalGas' resource plan, our continued scrutiny of utility resource plans may be incompatible with our shift towards competitive industries and performance regulation. Therefore, we intend to have staff address this question in the context of our Natural Gas Strategy and following that strategy, suggest a procedural roadmap for resolving resource plan issues in the future.

B. Replacement Cost Adder

ORA proposes the Commission apply the replacement cost adder methodology adopted for PG&E in D.95-12-053 and proposed for SoCalGas in this proceeding to SDG&E. It testifies this refinement is necessary in order to reflect the opportunity costs of replacing existing facilities.

SDG&E opposes ORA's recommendation stating its system is different from PG&E's and SoCalGas' and that nothing on this record to indicate the same problems exist with the SDG&E local transmission plan as with the PG&E transmission plan.

For the same reasons discussed earlier in the SoCalGas portion of this decision, the Commission should more properly consider a change to its adopted LRMC methodology in the context of our reexamination of our natural gas strategy where we can revisit the notion of using the adopted LRMC methodology to allocate costs between customer classes. Therefore, we will not adopt a replacement cost adder for SDG&E.

C. Marginal Demand Measures (MDMs)

SDG&E proposes to change two MDMs: the allocators for local transmission marginal costs and for SoCalGas system costs. It proposes to change the MDM for local transmission from cold year coincident peak month (CYCPM) to normal peak day (NPD). It states that the Commission clearly stated in D.92-12-058 that utilities design their local transmission systems for peak day, and that the MDM should follow from the design criteria to reflect cost causation in allocation. Further, it states the Commission based its decision to adopt CYCPM in D.92-12-058 on PG&E's system, which has backbone transmission and storage; SDG&E does not have these functions and its MDM should reflect this distinction. Further, it states that its SoCalGas system costs should be allocated on the same basis as its transmission costs, by NPD, not on the existing allocator of cold year throughput, because the physical facility costs external to the SDG&E system appear at its physical boundary as local transmission costs and should be treated as such. (Reply brief at 14-15.)

ORA objects to SDG&E's proposals and recommends retaining the existing MDMs. It states that D.92-12-058 rejected the same arguments SDG&E is making here and found that CYCPM was the appropriate local transmission MDM for both PG&E and SDG&E (47 CPUC2d 438, 455.) While SDG&E has no backbone or storage services of its own, it accesses these services through its contract with SoCalGas. SDG&E's witness testified during cross-examination that there was probably no physical difference between PG&E's local transmission system and SDG&E's (Tr. p. 2584).

ORA states that SDG&E's proposal to change its allocation factor for SoCalGas system costs is similarly flawed. SDG&E is paying SoCalGas to transport gas across SoCalGas' backbone transmission system and the allocation factor should reflect this.

Discussion

We agree with ORA. SDG&E has not provided any new evidence to support its proposal to change its local transmission MDM and its proposal to change the allocator for SoCalGas' system costs is not persuasive. Therefore, we will retain the existing MDMs.

D. Total Investment (TI) v. Discounted Total Investment (DTI) Method for Quantifying Marginal Capital Costs

SDG&E proposes to change the methodology for estimating the marginal cost of transmission capital investments from the TI method adopted in D.92-12-058 to the DTI method we rejected in the same proceeding. It bases its request on the Commission's directive in the recent PG&E BCAP, where we rejected PG&E's proposed Present Worth methodology but stated "we do see merit in exploring the idea of incorporating the time value of money in the calculation of capital-related marginal costs." (D.95-12-053, slip op. at 37.)

SDG&E states its methodology is the same as that discussed in D.92-12-058 (47 CPUC2d at 460-461).

ORA objects to SDG&E's proposal, stating it is not convinced the DTI method provides any significant benefit over the TI method and that it is inconsistent with the approach SDG&E uses for the distribution function. ORA states that SDG&E's design criteria, the APD, stays constant over the 15-year planning horizon, implying that the customer's preference for a service reliability level remains constant. Therefore, ORA is not convinced that there is sufficient evidence supporting the assumption that customers will actually discount the future projects since their demand for the service is likely to remain the same. It recommends the Commission retain the TI method.

<u>Discussion</u>

SDG&E has not provided any new evidence to support the adoption of DTI. The deficiencies in its resource plan, as discussed earlier, make it even more problematic for us to consider a methodology that incorporates a time-specific weighting factor to future investments. In D.95-12-053, we indicated only an interest in "exploring" the idea of incorporating the time value of money in the calculation of capital-related marginal costs. The record does not support adopting the DTI methodology.

<u>E. Replacement Cost for Distribution Mains and Service Lines</u>

ORA recommends eliminating the 25% adjustment to replacement cost for distribution mains and service. This is the same recommendation we adopted for PG&E in D.95-12-053 and that we adopt in this decision for SoCalGas.

SDG&E opposes ORA's recommendation, stating ORA presents no evidence that SDG&E does not experience higher costs for replacing distribution mains and service lines.

There is nothing unique to SDG&E's system to cause us to treat it differently. For the same reasons we eliminated a replacement adjustment for SoCalGas, we adopt ORA's recommendation here.

F. Marginal Customer Costs

1. Rental Method v. NCO

SDG&E proposes to use the NCO method for calculating marginal customer costs primarily since the Commission has already shown its preference for the NCO method over the rental method in recent marginal cost proceedings.

ORA recommends we retain the rental method for the same reasons it has supported the methodology for PG&E and SoCalGas.

The reasons we have previously stated in D.92-12-057, D.95-12-053, and D.96-04-050 and in our discussion of SoCalGas' BCAP application here, also apply to SDG&E. Therefore, we adopt the NCO method for calculating marginal customer costs.

2. Service Line, Regulator, and Meter (SRM) Costs

SDG&E proposes to calculate SRM costs based on the results of its construction and line extension computer-based estimating systems used in its field operations.

ORA testifies that to evaluate SDG&E's engineering estimates, it compared SDG&E's budget estimates for these facilities with its engineering estimates. These comparisons indicate that SDG&E's proposed SRM investment of $55 million is more than double the SRM investments included in its capital budget. Because of this unexplained disparity, ORA recommends a 25% reduction to SDG&E's SRM costs.

ORA also states that another indication that SDG&E's estimates are on the high side come from a comparison of SDG&E's customer marginal costs using the NCO method and TURN's proposed customer marginal costs using the NCO method in SoCalGas' BCAP. SDG&E's estimate of $133/customer for its residential customer is over 50% higher than TURN's $88/customer estimate for SoCalGas' residential customer.

We find ORA's testimony persuasive. We do not agree with SDG&E that the burden is on ORA to explain why its "checking" method results in such radically different values. (SDG&E Opening Brief at 33.) Rather, it is SDG&E's responsibility to explain why its engineering estimates produce such different values from its own budget forecasts and, further, why its estimated customer costs differ so greatly from those we adopt in this decision for SoCalGas.

Therefore, we adopt ORA's recommendation to apply a 25% reduction to SDG&E's SRM costs.

XI. Proposal to Unbundle Core Interstate Pipeline Demand Charges

A. Unbundling Interstate Pipeline Demand Charges

The Commission in D.95-07-048 stated that the unbundling of rates and services of the core class is consistent with the objective to promote competitive markets wherever possible. The Commission reiterated that the objective of introducing competition is to promote efficiency and drive down prices. However, the Commission went on to note that core participation in gas transportation markets may not lead to lower prices or increased efficiencies in transportation markets as a result of the excess interstate capacity which will be in place for the foreseeable future. The Commission concluded that SoCalGas and SDG&E should unbundle interstate transportation on or before January 1, 1999. The Commission noted this could be accomplished either in this BCAP or by separate application.

SDG&E chose not to use this BCAP to file its unbundling proposal. In their testimony, both ORA and Enron advocate that SDG&E unbundle its interstate transportation costs from core transportation customers' rates now rather than waiting until 1999 as the Commission outlined in D.95-07-048. In its rebuttal testimony, SDG&E responds that the proposals advocated by ORA and

Enron will not benefit SDG&E's customers and, in fact, core gas customers may pay more as a result. SDG&E opposes advancing the timetable for core unbundling without addressing the stranded interstate capacity cost situation to ensure that core gas customers taking bundled service will not end up paying higher costs as a result.

Discussion

On this last point we emphatically agree. An exercise that simply shifts cost responsibility from one set of customers to another does nothing to advance our efficiency objective. Unfortunately, the parties have left us with an undeveloped proposal which, though conceptually appealing, does not address the difficult stranded cost issues of calculation, allocation, and rate design. Enron would dismiss these issues as minor arguing that SDG&E has largely eliminated its long-term obligations for interstate pipeline capacity and thus the stranded cost issue. We disagree.

It is true that SDG&E holds only 10 MMcf/d of El Paso capacity, but this capacity is priced significantly over market by more that three times, according to evidence submitted. (SDG&E Rebuttal, Chap. VI, p. 7.) There is also uncertainty as to the value of SDG&E's PGT/PG&E-401 capacity relative to market valuations. If we assume, as Enron does, that only the El Paso capacity will be used by the core under long-term arrangements, the cost differential between the market and SDG&E's average core portfolio price for interstate pipeline demand charges would be 2.6 cents per decatherm. (SDG&E Rebuttal, Chap. VI, p. 7.) We agree with SDG&E "that a rate difference of this magnitude from the market price for gas supply represents the threshold level necessary to generate interest by independent gas brokers to market their services to SDG&E's core customers." (SDG&E Rebuttal, Chap. VI, p. 8.) Enron's participation on this issue in this proceeding is evidence of the attraction that this differential can have.

The presence of uneconomic capacity costs in SDG&E's rates will only tend to exacerbate the problem by encouraging customers to evade these costs embedded in SDG&E's average core portfolio price. As customers migrate from SDG&E service, the average core portfolio price will rise over the forecasted value as smaller amounts of cheaper brokered capacity are averaged with the higher cost fixed El Paso capacity. At some point these costs will have to be accounted for and recovered in rates. If unbundling does not explicitly account for these uneconomic costs, stranded cost of firm capacity will be shifted to remaining core customers taking bundled service, who will pay even greater above-market costs as a result.

Given that the market for capacity in 1999 will look similar to the market today, and we have no reason to believe otherwise, then the issue of how to deal with the over market value of long-term capacity in an unbundled world will have to be dealt with as part of any proposal. SDG&E does not raise any reason other than this for not advancing the timetable outlined in D.95-07-048.

We are left with two choices at this point, either retain the timetable outlined in D.95-07-048 and reject the ORA/Enron proposal to unbundle now or attempt to craft an unbundling proposal that explicitly recognizes and deals with the matter of SDG&E's above market long-term capacity, including PGT/PG&E-401 capacity, if appropriate. Given that we will confront this problem in the near term under the timetable we outlined in D.95-07-048, for administrative efficiency we will address this issue here.

Enron proposes that the at-risk SDG&E interstate pipeline demand charges above market could be recovered through a stranded capacity cost surcharge analogous to the ITCS currently in place for PG&E and SoCalGas. Although a volumetric surcharge is a less than optimal scheme for dealing with fixed uneconomic stranded costs, a surcharge could be designed that leaves customers choosing bundled service indifferent from a cost perspective. We disagree with SDG&E that this would necessarily cause an upward pressure on rates.

If we assume for illustrative purposes that the only above market capacity cost in SDG&E's core portfolio is the 10 MMcf/d of El Paso capacity, then the per unit differential between this and the per unit cost of brokered capacity times the 10 MMcf/d of capacity would be placed in an SDG&E-ITCS account with the balance recovered on an equal cents per therm basis from all core customers, whether they are taking bundled or unbundled service.

Using SDG&E's figures would result in a customer taking bundled service paying 12.84 cents per decatherm for interstate capacity reservation charges and 2.6 cents per decatherm in SDG&E-ITCS. This would equal the 15.44 cents per decatherm weighted average cost to core customers for interstate capacity reservation that SDG&E has proposed in its testimony. Customers taking unbundled service would pay the same 2.6 cents per decatherm SDG&E-ITCS and a separate charge for supply service from a third-party broker. This total may be greater than or less than the 15.44 cents per decatherm charge for bundled SDG&E service depending on how the broker's cost of capacity compares with SDG&E's brokered capacity cost. However, customers choosing the unbundled option would do so with the realization of the continuing cost responsibility they have for ITCS and intrastate service.

The outstanding question raised in comments to the proposed decision is the appropriate treatment of the 50 MMcf/d of PGT/PG&E-401 firm capacity that SDG&E holds. ORA argues that it is inappropriate for SDG&E to recover above market costs of this capacity in a surcharge from core customers since SDG&E is fully at-risk for these costs under its gas procurement performance-based ratemaking mechanism (PBR). Enron's comments also urge that these capacity costs not be considered in any stranded cost calculation.

ORA's point is well taken. However, we do not share ORA's recommendation that the issue of unbundling core rates be deferred. On the record before us, we do not have sufficient information for including these capacities in a stranded cost calculation. It is unclear that we will not unravel the risk/return balance established in SDG&E's PBR by ensuring recovery of potential above market capacity costs in this proceeding. For this reason, we will not include the PGT/PG&E-401 firm capacity that SDG&E holds in the stranded cost calculation.

If SDG&E believes it can develop a record to show that these capacity costs should be considered in a stranded cost calculation, then the company should file an application making the required showing. The application should discuss how the gas procurement rules in its PBR would be impacted by a decision to include this capacity in a stranded cost calculation and how the risk/reward balance achieved in the procurement PBR would be affected. SDG&E should also address in its application how the amended Firm Transportation Service Agreement between itself and PG&E as part of the Gas Accord impacts on this issue. The Commission would also value an historical comparison of SDG&E's delivered gas costs using its firm PGT/PG&E-401 capacity versus a southwest border cost of gas. This analysis should highlight basin gas price differentials as well as transportation cost differentials.

Given our exclusion of the PGT/PG&E-401 capacity from the stranded cost calculation in this proceeding, Enron's motion of October 29, 1996 to strike a portion of SDG&E's reply brief is now moot and will be denied.

SDG&E should file an advice letter establishing an SDG&E-ITCS balancing account to track the differential between its actual brokered capacity cost and the above market cost for the 10 MMcf/d of firm El Paso capacity. SDG&E should include in this advice letter filing the establishment of an initial surcharge to collect in rates from all core customers the cost differential between its brokered capacity costs and its above market firm capacity costs. This initial surcharge should be updated by advice letter filing whenever the unrecovered balance results in the surcharge changing by 10% or more on a sustained basis.

In addition, SDG&E testifies it strongly opposes Enron's proposal to unbundle its core storage costs. Enron, however, states it did not sponsor such a proposal (Opening Brief at 13). Therefore, we should not address the issue here.

XII. Throughput Forecasts

A. Cogeneration Gas Throughput Forecast

SDG&E forecasts operational cogeneration throughput at 443.8 million therms during the BCAP period. However, ORA notes a small error in the calculation of the forecast that SDG&E does not dispute. The revised forecast of 451.8 million therms is adopted.

B. UEG Gas Throughput Forecast

SDG&E originally forecasts 421 million therms annually (1,066 million for the BCAP period) for its UEG, based on historical data. In its application, SDG&E expresses the uncertainty regarding the upstream charges from SoCalGas and reserves the right to make changes to its UEG rate design proposal.

In its rebuttal testimony, SDG&E revises its forecast to 331 million therms per year, based on its concern that (1) SoCalGas will not renew its contract due to expire 12/31/96, thereby leaving SDG&E with an all-volumetric rate; and (2) an all-volumetric rate under ORA's proposal would translate to a significant rate increase that would have an adverse impact on the dispatch price of its UEG.

Subsequent to its testimony, SDG&E did successfully renegotiate its contract. However, the contract will require renewal again at 12/31/97. SDG&E states that while its extension of a gas transportation agreement between SDG&E and SoCalGas mitigates its concern with ORA's proposals, it does not eliminate its concern. Because SDG&E is unsure whether its contract with SoCalGas will be extended beyond December 31, 1997, it recommends that ORA's proposals be rejected or if adopted, then its UEG forecast be revised to 331 million therms annually.

ORA believes the contract can be extended again for the remainder of the BCAP period and recommends adoption of SDG&E's original forecast.

SDG&E does not present sufficient justification for revising its forecast and, therefore, we adopt a UEG forecast of 421 million therms per year.

XIII. Core Brokerage Fee Study

SDG&E proposes a core brokerage fee of $0.00057 per therm based on its marginal cost study. It states its proposal complies with the Commission's direction in D.95-07-048 that "our preliminary thinking is that the core brokerage fee should be based on the marginal cost of utility core procurement" (Id. at 8.)

Enron testifies that SDG&E's marginal cost study fails to meet the Commission's standard and must be rejected. It states SDG&E bases its study on an assumption of a 50% increase in demand but does not justify the choice of this increment or establish that a direct correlation exists between this incremental increase and the cost of providing procurement service. Further, Enron cites to SDG&E's testimony on cross-examination that lower increment (i.e., 10%) would have included no costs. (Opening brief at 11.)

Enron states that SDG&E's gross understatement of costs is demonstrated by comparing SDG&E's study to a data request provided by SDG&E and included in the record as Exhibit 207. Enron states Exhibit 207, which reflects some of the embedded costs associated with the procurement function, establishes why SDG&E should be required to perform a complete embedded cost study including all of the costs of the procurement function to calculate a more accurate brokerage fee.

We agree with Enron that SDG&E's marginal cost study is not valid for purposes of calculating a core brokerage fee. We do not find, however, that SDG&E should perform a complete embedded cost study, as the regulatory cost of further litigation on this issue is not warranted. Similar to our findings for SoCalGas, we will calculate a core brokerage fee using average cost data but excluding overhead based on the data provided in Exhibit 207. As Exhibit 207 reflects cost data for procurement activity related to both core and noncore customers, we allocate the costs over annual purchase volumes of 965 million therms, thereby deriving a core brokerage fee of $ 0.00092 per therm.

SDG&E in its comments on the proposed decision states that in its application it also requested authority to establish a noncore brokerage fee and requests we address requests that we also set a noncore brokerage fee. This request appears reasonable, therefore, we adopt a noncore brokerage fee of $ 0.00092 per therm. We direct SDG&E in the future to separately track the costs of core and noncore procurement related activity, especially marketing related costs.

Brokerage-related costs equal to the estimated volume of utility core sales should be removed from core transportation rates and included in core procurement rates instead. Consistent with existing practice for SoCalGas, this brokerage fee revenue requirement should be subject to balancing account treatment to eliminate the incentive that would otherwise be created for the utility to promote sales of its own gas.

XIV. Global Settlement Prepayment

The Global Settlement obligation results from the Global Settlement approved by the Commission in D.94-07-064 which specified how costs will be shared between SoCalGas shareholders and customers, regarding transition costs associated with PITCO and POPCO gas supply contracts.

In our last BCAP decision, D.94-12-052, we authorized SDG&E to accelerate collection of its Global Settlement obligation from customers. D.94-12-052 states:

> "SDG&E should incorporate in rates set in this BCAP early amortization of its obligation under the Global Settlement provided that no rate increase results. SDG&E shall set up a tracking account to establish when its obligation to SoCalGas has been satisfied." (Id. at 98.)

Existing gas sales and transportation rates consist of two components related to the Global Settlement obligation. A charge of $0.1091/Dth collects annual Global settlement costs allocated from SoCalGas and $0.1749/Dth prepays costs authorized in D.94-12-052. Thus, there is a total of $0.2840 in Global Settlement obligation charge in current rates.

SDG&E proposes to terminate the collection of all Global Settlement related costs and remove the $0.2840/Dth from rates effective January 1, 1997 and use the funds in the Global Settlement Prepayment Tracking Account (GSPTA) to settle its obligation to SoCalGas under the Global Settlement. SDG&E, however, wants to reserve the right to petition the Commission to resume collecting a Global Settlement charge if it appears that the balance in GSPTA is insufficient to meet its actual obligation. SDG&E forecasts a balance of $40.5 million at December 31, 1996 for the GSPTA.

ORA's primary concern is that SDG&E has been unable to negotiate a Global Settlement prepayment with SoCalGas since January 1995 when it started collecting funds from ratepayers. ORA believes that the Commission authorized the early collection of SDG&E's Global Settlement obligation in anticipation that SDG&E would reach a settlement with SoCalGas. ORA feels that the ratepayers are better off without the prepayment.

SDG&E refutes ORA's concerns and testifies that it has acted properly in order to avoid a rate shock to its customers. SDG&E claims that it attempted to estimate its obligation to SoCalGas under the Global Settlement by presenting three scenarios in Chapter VII of its application. Based on its Base Case Scenario estimate of $36.0 million (others include Low Cost Scenario, $31.6 million; High Cost Scenario, $49.4 million), it decided to terminate the collection of these rates effective January 1, 1997.

Discussion

We will remove the Global Obligation rates as SDG&E proposed and terminate their collection immediately. SDG&E can use the amount in the GSPTA to pay SoCalGas on a monthly basis. The GSPTA should remain open until the next BCAP but any overcollection as a result of the disposition of the Global Settlement obligation should be timely refunded to ratepayers by advice letter filing. Any undercollection will be addressed in either the next BCAP, or the appropriate proceeding noted in the roadmap which we expect to follow our Natural Gas Strategy.

XV. Audit Issues

ORA did not perform an audit of any SDG&E accounts for this proceeding. In response to the ALJ's concerns, ORA on September 5, 1996 provided a plan for auditing eight gas balancing accounts (Exhibit 218). ORA expects to issue its report in mid-January 1997 and SDG&E will be given the opportunity to comment. No party objects to this proposal. We find it reasonable and adopt it.

XVI. Gas Revenue Requirement

SDG&E recommends we use the revenue requirement adopted for SDG&E under the SoCalGas application, A.94-03-041, with an adjustment for the Moreno Compression Credit, as reflected in Exhibit 204. We find this proposed reasonable and adopt it.

XVII. Rate Design

A. Residential Tier Closure

SDG&E initially proposed a nonbaseline to baseline ratio of 1.35 to 1.00. ORA in its testimony proposes a ratio of 1.25 to 1.00 and recommends this be achieved by applying virtually all of its recommended residential class revenue requirement decrease to the nonbaseline rate.

In its rebuttal testimony, SDG&E specifies one condition for acceptance of ORA's proposal: the implementation of a targeted tier closure must not produce a rate increase to the baseline residential rate. ORA agrees.

Although PG&E and SoCalGas have a 35% tier differential for their residential gas rates, we find it appropriate for SDG&E to have a lower differential because it does not have a customer charge. According to PU Code § 739(a), the baseline quantity of gas should represent "a significant portion of the reasonable energy needs of the average residential customer," and the customer charge and baseline rate are the price of this quantity. Therefore, the baseline rate can be higher in the absence of a customer charge. We adopt ORA's proposal of a tier differential of 1.25 to 1.00.

B. Core Deaveraging

SDG&E proposes allocating 60% of its recommended core decrease to the core commercial class, which would provide for further core-deaveraging while allowing a larger rate decrease (i.e., 2%) to its residential customers than was granted in SDG&E's last BCAP.

ORA does not oppose the concept of further deaveraging of residential and core commercial rates, but recommends that the residential rate decrease be at least 5%. ORA's proposed rates reflect the level of deaveraging incorporated in SDG&E's original filing, and produce a 7% residential rate decrease.

The update filing by SDG&E does not provide the same level of rate decrease as originally recommended by ORA under its proposals. We find it reasonable to use the level of deaveraging incorporated in SDG&E's original filing. This level of deaveraging provides the 2% residential rate decrease recommended by SDG&E and allocates 70% of the core decrease to the core commercial class.

C. Core Commercial GN-1 and GN-2 Schedules

SDG&E proposes to make the following changes:

1. For Schedule GN-1:

   (a) Lower the applicability of the amount of gas billed at the Tier 1 rate from 3,000 to 1,000 therms per month; and

   (b) To the extent that there is a decrease for this customer group, allocate the decrease to the Tier 1 rate.

2. For Schedule GN-2:

   (a) Increase the applicability of the amount of gas billed at the Tier 1 rate from 3,000 to 6,000 therms per month; and

   (b) Increase the customer charge from $60 to $75 per month. (Exhibit 201, Chapter X-4.)

ORA does not oppose this proposal, although in its rebuttal SDG&E mistakenly assumes otherwise. (ORA Opening Brief at 17.)

We find SDG&E's proposal is reasonable; therefore, it is adopted.

D. Transmission Level Service

SDG&E's rate design proposals include establishing a transmission level service for noncore customers who receive natural gas service directly from its transmission mains. It defines this as a service provided directly from its natural gas transmission pipe with a diameter of 10 inches or greater, operating at a hoop stress of 20% or more of specified minimum yield strength (SMYS), and a minimum rating of 400 pounds per square inch gauge (psig) at maximum allowable operating pressure (MAOP).

SDG&E states its proposal continues the trend towards more specific service level distinctions for noncore customers initiated by D.93-05-066, the LRMC implementation decision. The customers it believes qualify for its transmission level service are five cogeneration and seven UEG customers.

Kelco, a large noncore customer whose cogeneration load would qualify for the new service, supports SDG&E proposal. Kelco believes transmission level service rates should be adopted for SDG&E because the Commission had already approved such proposal for SoCalGas and PG&E. Kelco argues, "to deny qualifying SDG&E customers the availability of a service that is similar, if not identical, to offerings previously approved by the Commission for PG&E and SoCalGas would be grossly unfair and highly discriminatory" (Opening Brief at 8). Kelco believes that SDG&E's proposal will eliminate the current subsidy of other SDG&E customers by those customers who receive their gas deliveries directly from gas transmission mains.

Kelco agrees with SDG&E that SDG&E's proposal better aligns rates with the design and use of the gas system and that it costs less to serve transmission customers because of their proximity to SDG&E's facilities. Kelco and SDG&E believe that Commission's action in the LMRC implementation proceeding recognizes that the utilities could experience a substantial bypass of their gas systems by their largest customers if gas rates are not competitive with bypass alternatives. In its reply brief, Kelco asserts that even if the Commission finds that SDG&E's

proposal will unduly benefit SDG&E's UEG, at a minimum it should adopt a transmission level service for qualifying nonUEG customers.

ORA opposes SDG&E's proposal because of (1) SDG&E's failure to provide clear notice of this major issue and adequate time for ORA to properly review the issue; and (2) the significant cost shifts that it would create. ORA testifies that SDG&E's proposal to change the service level of 12 noncore customers would lower UEG customers' marginal cost revenues from $4.5 million to $2.6 million and also reduce cogeneration's marginal cost revenues from $7.0 million to $4.9 million, resulting in significant costs being shifted to other gas customers.

ORA asserts that SDG&E is proposing this change to further the interest of its UEG in the newly competitive electric industry. In support of this assertion, ORA testifies that SDG&E reduces the MAOP for transmission pipe from a minimum of 595 psig in the last BCAP to 400 psig in this BCAP; this lower level allows its UEG to qualify for the service.

Discussion

In D.92-12-058, we directed the respondent utilities "to work with interested parties to provide the information necessary for us to consider segmentation proposals that include service level distinction in the implementation proceedings." (47 CPUC2d at 470.) The three utilities filed their proposals in separate applications and each reached a settlement with interested parties. In D.93-05-066, we adopted the three settlement agreements submitted by the utilities.

PG&E proposed a service level industrial class segmentation, with two segments, transmission and distribution. The transmission segment consists of all customers receiving service on backbone local transmission or distribution feeder mains. Customers under the transmission schedule must be served directly from PG&E gas facilities that have a MAOP greater than 60 psig or meet annual service demand requirement of 3,000,000 therms.

SoCalGas' adopted proposal segregated industrial service based on medium-pressure distribution (MPS), high-pressure distribution (HPS), and transmission level service. Appendix C to the settlement agreement under "Eligibility" states that MPS customers receive service from distribution lines at pressures equal to or less than 60 psig and HPS customers receive service from distribution lines greater than 60 psig. Customers can move from MPS to HPS based on the customer's consumption pattern for the most recent 12 months. For transmission service, Special Condition 29 under Schedule No. GT-F (Firm Intrastate Transmission Service) states, "Customers served from the Utility's transmission related facilities as established by the Utility's capital accounting records, shall be classified as transmission GT-F3T." These customers, at their option, can elect HPS rate status.

SDG&E's proposed segmentation in the implementation proceeding was similar to that of SoCalGas except for the absence of transmission level service. SDG&E's Schedule GTNC (Natural Gas Intrastate Transmission Service For Noncore Customers), however, states that "HPS shall also be applicable to those customers who are receiving gas deliveries from the utility, where rated pipeline pressures, as determined by the utility, at the point of interconnection with the customer's facilities exceed 60 psig as of June 1, 1993."

We find it difficult to compare PG&E, SoCalGas, and SDG&E's criteria for the same type of service. SDG&E suggests all three utilities meet the federal definition of transmission pipe. PG&E adopted MAOP in excess of 60 psig for its transmission service while SoCalGas did not specify any level of pressure. Neither specifies the hoop stress of its pipe, a critical component of meeting the federal definition.

SDG&E testifies that one of its criteria for its transmission level service proposal is the Commission's definition of transmission pipe found in General Order (GO) 112-E, which governs the design, construction, testing, operation and maintenance of natural gas facilities. The GO incorporates all of Title 49 of the Code of Federal Regulations (49 CFR) Parts 190, 191, 192, 193, and 199. Part 192 defines "Transmission Line" as a pipeline, other than a gathering line, that:

a. Transports gas from a gathering line or storage facility to a distribution center or a storage facility.

b. Operates at a hoop stress of 20% or more of SMYS.

c. Transports gas within a storage field.

While SDG&E uses the engineering standards of GO 112-E as one of its proposed criteria, it does not establish that the Commission has previously used GO 112-E as a rate design criteria in establishing transmission level service offerings for PG&E and SoCalGas. The following table shows service level distinctions among the three utilities for comparison purposes.

Service Distinctions

	Distr.	Criteria	Trans.	Criteria
SDG&E	MPS HPS	less 60 psig 60 psi or more*	Proposed	10 in. pipe and more than 400 psig
SoCalGas	MPS HPS	less 60 psig 60 psi or more	Yes	Capital Records**
PG&E	single category	less 60 psig	Yes	60 psig or more than 3,000,000 therms

* SDG&E proposes to change its HPS criteria from 60 to 99 psig.

** Tariff does not specify psig level or other criteria.

This table shows that SDG&E and SoCalGas have the same MAOP for MPS and HPS distribution systems while PG&E adopted less than 60 psig for its distribution system and 60 psig or more for transmission. SDG&E proposes to change the MAOP of its HPS but does not explain why it should have a higher MAOP than SoCalGas. The record does not reflect the SMYS criteria used by PG&E and SoCalGas for transmission level service, or the minimum psig used by SoCalGas for this service.

Although SDG&E's proposal for transmission level service utilizes different service pressure and pipeline size thresholds than either SoCalGas or PG&E, SDG&E's proposal is based upon its unique system characteristics that define the ability of an SDG&E customer to take service off a transmission main. Most importantly, establishing transmission level service for SDG&E is consistent with our principles of allocating costs to those customers who cause them. Currently, customers on SDG&E's system who take service off a transmission main are allocated gas distribution system costs despite the fact that they do not utilize the gas distribution system. Establishing transmission level service removes this subsidy. For these reasons, we adopt SDG&E's proposal for tranmission level service.

E. UEG Rate Design

Other than the transmission level proposal discussed above, SDG&E's application proposes no change to its existing UEG rate design.

In its rebuttal testimony, SDG&E proposes changes to the calculation of the UEG components based on the uncertainties surrounding its renegotiation of a new master agreement with SoCalGas.

ORA does not oppose retaining SDG&E's existing UEG rate design and recommends that the Commission disregard SDG&E's rebuttal testimony with respect to UEG rates because subsequent events have superseded this testimony.

Discussion

We agree with the ORA that subsequent events have superseded SDG&E's uncertainty with respect to its contract with

SoCalGas. It signed a new contract with SoCalGas, and while this contract will expire at the end of 1997 unless renewed, there is no indication SoCalGas would not again renew its contract. Therefore, we retain the existing UEG rate design.

Based on comments on the proposed decision, we provide clarification on how the UEG rate design is calculated in Appendix C. Appendix C is calculated using SDG&E's workpapers, Exhibit 205, supporting the following testimony in its application:

> "Default utility gas transportation services for SDG&E's power plants are provided under Schedule GTUEG. The current UEG rate design for transportation services consists of a fixed monthly demand charge, and three tiers of volumetric rates applied to three different blocks for gas usage. The first increment of gas usage is billed at the igniter fuel rate, which historically amounts to approximately 1% of total UEG gas volumes consumed. Since igniter fuel volumes and costs are capture in the GN-2 customer class for purposes of cost allocation, it is appropriate that the igniter fuel rate should equal the average GN-2 rate for unbundled intrastate transportation services. The second increment of gas usage is billed at the Tier 1 rate, which is applicable to the first 18.5% of forecasted UEG gas volumes adopted in a BCAP, net of igniter volumes. The balance of UEG gas usage is billed at the Tier 2 rate. In prior BCAPs, SDG&E has requested and received authority to set the Tier 2 rate equal to the transport charges paid to SoCalGas for incremental volumes. This ratemaking procedure captures the notion that SDG&E should recover, at a minimum, its upstream costs for incremental services.
>
> "SDG&E is proposing no changes to the existing UEG rate design at this time." (Exhibit 201 at X-11.)

F. Schedule XGTS

SDG&E created Schedule XGTS as part of its proposal to introduce real-time pricing (RTP) for its Gas Department in the last BCAP. The Commission adopted SDG&E's proposal, which included Schedules XGSR for residential customers and XGTS for all other customers, with modifications. The Commission excluded UEG and cogeneration customers from Schedule XGTS and limited noncore customer participation to 10 per year. The Commission also imposed the following conditions: A provision of a 24-hour nonbidding forecast of contract closures; establishment of a separate core and noncore balancing account and off-peak allowances equal to the customer's peak day usage during the last 12-month billing periods, divided by 24, and a progress report of the program to ORA for monitoring purposes. (D.94-12-052, slip op. at 79-80.)

SDG&E proposes no changes to its rate design under Schedule XGTS. However, it wants to expand service eligibility to include some cogeneration and UEG loads and revise the customer maximum hourly peak-day demand allowance.

SDG&E believes that cogeneration and UEG customers are leaders in managing their energy use and as a result, could optimize utilization of SDG&E's pipeline system by shifting sizable load in a timely manner. It proposes to limit UEG and cogeneration participation in Schedule XGTS to 25% of their total load adopted in this BCAP in order to mitigate unexpected revenue shortfalls. SDG&E believes that UEG and cogeneration participation is essential to determine the success or failure of the program.

SDG&E's proposal also wants to revise the calculation of the maximum hourly demand to equal the customer's peak day usage divided by the number of normal operating hours of the facility. Currently, this is defined as equal to the customer's highest recorded gas demand, stated in therms per hour, during the current and prior 11 monthly billing periods excluding billing periods prior to January 1, 1995. SDG&E believes this calculation has dissuaded some customers from participating in the experimental program because they operate their business 8 hours a day, not 24 hours.

ORA opposes SDG&E's proposal because the program has been a costly experiment, and opening Schedule XGTS to UEG and cogeneration loads will only compound the problem by benefiting SDG&E's own UEG and shareholders at the expense of other gas ratepayers. ORA points to Scenario C, the worst case, illustrated by SDG&E in its response to SCUPP/IID data request, to support its position. ORA alleges that with limited volume and lower UEG rate used for that scenario, there is still a $1 million revenue shortfall. ORA, therefore, recommends that Schedules XGTS and XGRS be closed to new customers and terminated effective April 1, 1997. ORA also wants the amount in the Real Time Balancing Account to reflect a 25% allocation to SDG&E's shareholders. ORA recommends that if the Commission retains the schedules, it should amend the definition of peak day demand, assign 100% of the revenue shortfall to SDG&E's shareholders, and continue to exclude UEG and cogeneration customers, particularly UEG because SDG&E has no need to provide any further discounts to its UEG in order to balance gas loads; UEG loads under the interruptible rate schedule are curtailed prior to any other customer load.

SDG&E believes that participation under Schedule XGTS does not guarantee customer saving or PBR rewards for SDG&E and its customers since these depend on conditions that SDG&E or its customers cannot control, such as weather. SDG&E, therefore, argues that one customer's experience in an "extremely warm year" should not be used to judge the program, by extrapolating the revenue shortfall into several millions for future events, contrary to what SDG&E had demonstrated in its response to SCUPP/IID data request.[24] SDG&E believes that UEG and cogeneration participation holds operational benefits to SDG&E's gas system because these are efficient gas users that may optimize the use of its natural gas system given the appropriate price signals.

Kelco, the only customer under Schedule XGTS, also filed testimony in support of continuation and expansion of the program, particularly to cogeneration loads, in order to reduce its uncompetitive gas transportation costs. Kelco supports its assertion by citing RTP objectives as represented by SDG&E in the last BCAP and Commission's electric industry decisions that are in favor of time of use (TOU) pricing. Kelco's further arguments will not be repeated since they are similar to SDG&E's.

1. Discussion

We agree with ORA with respect to its concern for revenue shortfalls. We will not expand the service eligibility as proposed by SDG&E but we will keep Schedule XGTS for the BCAP period with any future requirement that SDG&E shareholders will be at risk for 25% of the revenue shortfall. We adopt SDG&E's proposal for the calculation of off-peak allowances. As there has been no residential customer interest in Schedule XGSR, we adopt ORA's recommendation to eliminate the tariff. SDG&E should work with ORA, TURN, and other interested parties to develop alternative residential programs. We will consider revisiting the future of the RTP schedules in our Natural Gas Strategy.

24 Attachment C of SDG&E's rebuttal testimony on rate design (Exh. 203, Chapter VI) contained several data request responses. In data request response labeled SCUPP/IID Data Request No. 1, Table A - Response to Question 5.9, SDG&E illustrated three possible outcomes of a UEG unit's participation under Schedule XGTS based on a typical year weather pattern, with variations due to response to peak pricing signals. Scenario C, a worst-case, from SDG&E's perspective, shows a $1.0 million revenue shortfall.

G. Liquefied Natural Gas (LNG) Rate

SDG&E has one LNG customer, the Roadrunner Club, a 312-space mobilehome park located in the desert community of Borrego Springs. SDG&E initiated LNG service as a pilot test in May 1968. It recruited a total of 31 large customers and communities, including the Roadrunner Club. The service has not been successful and SDG&E has terminated service to all but the Roadrunner Club. LNG revenues from the Roadrunner Club are about $138,000 per year.

SDG&E proposes to increase LNG rates by 5% annually until the total LNG charge recovers SDG&E's cost for providing LNG service. ORA opposes a rate increase but recommends that any rate decrease to LNG should lag other residential decreases by 2%.

Wright & Company, the owner of the Roadrunner Club, and the Roadrunner Club Association Inc., an association of mobilehome owners and residents in the Roadrunner Club, oppose the proposals by SDG&E and ORA because they contradict prior Commission decisions. They cite D.90-11-023, SDG&E's 1990 cost allocation proceeding, where the Commission said it would "...not approve rates that would increase the Roadrunners' average combined LNG and electric bill to exceed the average Borrego Springs all-electric bill" (38 CPUC2d 77, 112) and D.91-12-075, SDG&E's 1991 proceeding, where the Commission reaffirmed its position (42 CPUC2d 566, 608). The Roadrunner Club states that under this standard, it should receive a 9.3% rate decrease.

On August 23, 1996, SDG&E, ORA, and the Roadrunner Club signed a Joint Recommendation (Exhibit 212) that the Commission adopt a 4% reduction to SDG&E's existing Average Full Service LNG Rate. The Roadrunner Club states that this agreement will allow the parties to set aside their dispute concerning the appropriate rate level and focus on developing a long-term solution to the issues related to a unique SDG&E customer. (Opening Brief at 3.)

Based on the above discussion, we find this recommendation reasonable and we adopt it.

H. Cogeneration Parity

SDG&E states it did not address this issue because it assumes that the ruling of the Commission on the issue for SoCalGas will also apply to it. No party opposes this proposal. Therefore, we adopt the same cogeneration parity proposal for SDG&E.

XVIII. Uncontested Issues

SDG&E proposes in its application several changes that no party contests. These changes are:

- Simplification of its gas procurement tariffs for noncore customers. SDG&E proposes to reduce the number of itemized costs listed under its Schedule GCORE, core subscription services, from five to two. Further, it proposes to offer utility gas procurement services to noncore customers under one tariff rather than three. Lastly, it proposes to eliminate Schedule G-USTOR, a tariff that provides gas storage services for noncore customers who elect utility-managed procurement services.

- Proposed revisions to its Gas Rule 14, rules and procedures for gas curtailment. SDG&E proposes changes that it states are effectively clean-up items that will update its Rule 14 to conform with Commission-adopted changes on storage and transportation unbundling for SDG&E over the past few years.

- Proposal to add a separate line item to its noncore gas transportation tariffs to reflect recovery of Wheeler Ridge access fees. SDG&E states this proposal does not add any new charges, but simply "calls out" the Wheeler Ridge costs from total rates.

We find SDG&E's above proposals to be reasonable; therefore, we adopt the proposals.

Findings of Fact

1. In A.96-03-031, SoCalGas seeks a $137.7 million annual decrease in rates over the coming 31 months to reflect (1) the allocation among customers of the nongas costs of service previously authorized by the Commission for recovery in rates; (2) the amortization of the balances as of December 31, 1996 in various balancing, tracking and memorandum accounts previously authorized by the Commission; and (3) the forecasted cost of purchased gas for core customers.

2. In A.96-04-030, SDG&E proposes a annual rate decrease of $42 million based on its BCAP filing for the same 31-month period requested by SoCalGas.

3. In its update filing of October 15, 1996, SoCalGas requests an overall rate decrease of only $55.7 million, down from $137.7 million, due to changes in the forecasted level of its balancing accounts at December 31, 1996. SDG&E in its update filing of October 25, 1996 reflects an overall decrease of $26.98 million, down from a $42 million decrease.

4. The update increases of both applicants are attributable exclusively to revised forecasts of regulatory account balances that are under a balancing account mechanism.

SoCalGas Storage Program

5. SoCalGas has excess capacity in both its existing and expansion storage facilities.

6. SoCalGas does not establish that the additional capacity at Honor Rancho existed prior to its 1992 storage filing and that it could not be properly measured at that time.

7. There is only limited market interest in firm injection capacity, about 4 MMcf/d.

8. SoCalGas' storage field is being routinely fully utilized; therefore, it makes no sense to lower the amount of firm injection capacity for cost allocation purposes.

9. The additional 1.5 Bcf of capacity at Honor Rancho should be considered part of SoCalGas' expansion capacity.

10. SoCalGas should directly address the problem of large storage system overdeliveries on summer weekends by enforcing penalties for overdeliveries and by marketing its available capacity to customers who consistently overdeliver. We should retain 803 MMcf/d of firm injection capacity for cost allocation purposes.

11. SoCalGas' proposal to change the peak hour requirement to a 24-hour requirement for calculating firm withdrawal capacity is reasonable and should be adopted.

12. SoCalGas has not provided sufficient justification to reclassify the capacity of Playa del Rey.

13. We should adopt a firm withdrawal capacity of 3,381 MMcf/d, a 10% reduction from the existing level of 3,757 MMcf/d.

14. We should adopt a retail core firm withdrawal reservation of 1,985 MMcf/d.

15. Following the issuance of the Commission's Natural Gas Strategy, the Executive Director should direct staff to determine a procedural roadmap to ensure the proper proceeding wherein SoCalGas should provide a study of its storage operations. The study should include a) the cost-effectiveness of reserving varying amounts of withdrawal capacity versus other potentially less expensive alternatives (such as procuring more gas supplies at market rates on peak days), b) a clear definition of firm injection service, and c) a new load balancing study for injection capacity.

16. SoCalGas' recommended load balancing inventory level (5.3 Bcf) and withdrawal level (250 MMcf/d) are reasonable and should be adopted.

17. We should adopt a 355 MMcf/d injection level.

18. SoCalGas has "sold" more expansion withdrawal capacity than it has constructed, and intends to keep the excess revenue

(about $900,000 per year), even as its ratepayers are forced to pay for stranded existing facilities.

19. For purposes of cost allocation, SoCalGas should treat all marketed capacity as existing capacity as long as any existing capacity remains unmarketed; this requirement applies to all storage contracts, including off-system storage contracts.

20. SoCalGas' proposed modifications to the imbalance trading procedures should improve SoCalGas' load balancing service, therefore, we should adopt its proposal.

21. We should not adopt Enron's proposal to unbundle core storage in this BCAP.

22. We find SoCalGas has shown good cause for its request to eliminate the G-SWAP service.

LRMC Methodology

23. In D.92-12-058, the Commission directed that resource plans be filed in general rate cases rather than BCAPs in order to allow parties sufficient time to examine the complex issues.

24. Both SoCalGas and SDG&E include resource plans in their applications without having requested, or been granted, Commission authority to deviate from the filing requirements of D.92-12-058.

25. The Commission and interested parties need more time and resources to thoroughly review the utilities' resource plans.

26. SoCalGas includes investments such as the Adelanto Rewheel and Line 115/765 Uprating projects in its resource plan that are not growth-related; these investments are included by SoCalGas to provide the system more operational flexibility and to allow its customers increased access to alternative gas commodity markets.

27. Significant changes have occurred in SoCalGas' long-term forecast and, correspondingly, its proposed resource plan since its last BCAP proceeding in 1994.

28. The issues raised by parties regarding SoCalGas' long-term demand forecast and its transmission resource plan are

significant and beyond the scope of this proceeding to fully resolve.

29. SoCalGas has not shown the reasonableness of the manner in which it proposes to include the expansions of Line 6900 and 6902 in its transmission resource plan; therefore, the specific ratemaking treatment to be given Line 6900 and Line 6902 should be further investigated and fully resolved prior to final Commission action on the proposed Pacific Enterprises/Enova merger.

30. The specific problems with our adopted LRMC methodology that ORA identifies as needing further investigation will require a commitment of considerable Commission resources and a proceeding schedule similar to a GRC, not a BCAP.

31. We should use SoCalGas' filed resource plan for purposes of calculating LRMC methodology unless, and until, the Commission's later review of Lines 6900 and 6902 leads us to order a new resource plan filing; therefore, we should adopt for this BCAP a transmission resource plan of $88.53 million and a storage resource plan of $68.60 million.

32. Including future replacement costs is not an embedded costing methodology.

33. The gas industry is between the telephone and electric industries in its movement toward competitive markets.

34. Although in D.95-12-053, we found that including a replacement cost adder in PG&E's resource plan met the definition of marginal cost that we adopted in D.92-12-058; the evidence presented in this proceeding does not support the same finding.

35. The Global Settlement does not allow addition of replacement costs to the LRMC metholdogy because it results in a significant cost shift.

36. The Commission should more properly consider changes to the LRMC methodlogy in a reexamination of natural gas policies and strategies.

37. Staff should recommend a procedural roadmap following issuance of our Natural Gas Strategy which incorporates the analysis recommended by TURN examining the full cost and cost allocation ramifications of three alternative reliability standards.

38. For this proceeding, we find it reasonable to adopt SoCalGas' proposed 38-degree peak day design criteria.

39. We should retain cold year throughput as the cost allocator for transmission investments.

40. SoCalGas' proposals to change the MDMs for load balancing injection and withdrawal are reasonable and should be adopted.

41. SoCalGas has not presented sufficient justification that the MDM for load balancing inventory should be changed. We find the allocator should remain the same as that adopted in D.94-12-052.

42. SoCalGas should be able to institute the same level of efficiency and innovation as PG&E over the next thirty years. Therefore, we should remove the replacement cost multiplier factor from the calculation of replacement costs for service lines and distribution mains.

43. The New Customer Only (NCO) method is preferable to the rental method for measuring marginal customer capital costs.

44. The language in the Global Settlement classifies all marginal cost allocators as MDMs; therefore, in compliance with the terms of the Global Settlement, we should retain the use of the rental method for interclass cost allocation.

45. SoCalGas' revised service line, regulator and meter figures are reasonable and should be adopted.

46. SoCalGas should provide the following information with respect to its active meters and connected meters in the appropriate forum designated by the procedural roadmap issued following our Natural Gas Strategy: (1) a clear definition for

each category; (2) an explanation of how it collects the data for each category; (3) an illustration of how it uses each category and for what purpose; and (4) the O&M costs associated with exclusive use facilities assigned to the noncore in its marginal cost calculations.

47. It is reasonable to continue to treat compressor fuel as an LRMC component.

48. ARCO lease costs should be included as part of transmission O&M.

49. SoCalGas's proposal to maintain the zone rate credit eligibility limitations on Wheeler Ridge volumes established in its last BCAP and to prospectively return the credits this generates to its customers is reasonable and should be adopted.

50. SoCalGas should file an advice letter within 20 days showing how past savings resulting from the zone rate credit limitation have been or will be returned to ratepayers.

51. We should retain the existing scaler methodology. Wholesale customers should not be exempted from the scaler.

Interstate Pipeline Capacity Costs

52. In January 1996, SoCalGas exercised its contract right to step down capacity on El Paso from 1,450 MMcf/d to 1,150 MMcf/d. In November 1996, SoCalGas reduced Transwestern capacity from 750 MMcf/d to 300 MMcf/d.

53. The capacity stepdowns should help alleviate SoCalGas' stranded costs of interstate pipeline capacity, especially over the longer term. For the next few years, however, SoCalGas expects to pay a substantial surcharge over the base rates for its 1,450 MMcf/d of remaining interstate pipeline capacity.

54. Eliminating the core reservation in this BCAP could exacerbate excess capacity costs at a time when SoCalGas' customers will be faced with increased pipeline surcharges and the need to amortize large stranded cost balances. For these reasons, the Commission should maintain the schedule established in D.95-07-048

for the unbundling of interstate reservation charges from core rates by 1999.

55. The evidence does not support a change to the core reservation beyond a small downward adjustment for core migration to the noncore class.

56. The core reservation should remain based on forecast cold year requirements. We should adopt SoCalGas' proposal for a core reservation of 1,044 MMcf/d, consisting of 744 MMcf/d of El Paso capacity and 300 MMcf/d of Transwestern capacity.

57. We should maintain the allocation of ITCS to core customers in an amount equal to 10% of the core capacity reservation as established in D.92-07-025.

58. The core's cost responsibility for the core capacity reservation should include the base transportation rates in El Paso and Transwestern's tariffs, and any surcharges on the base rates which FERC has already or may in the future authorize to mitigate the pipelines' risk of unsubscribed capacity.

59. The record does not support SDG&E's proposal to allow SoCalGas to keep 10% of the capacity brokering revenues.

60. All internal company capacity brokering transactions should be made public to ensure that transactions occur at a fair market price; therefore, SoCalGas should post such transactions on its Gas Select bulletin board and the pipeline's bulletin board. This rule should apply to all prospective internal transactions involving SoCalGas' interstate capacity rights.

61. We should maintain the established framework regarding the allocation of capacity stepdowns. The core should pay the full cost of its capacity reservation (1044/MMcf/d) including base rates, an allocation of ITCS equal to 10% of its reservation, and surcharges, and the noncore will pay the remaining cost of 406 MMcf/d in capacity, including base rates and surcharges, through the ITCS. SoCalgas should account for these costs separately.

62. Wholesale customers should bear a full share of the ITCS costs if they do not take their full assignment of SoCalGas'

interstate pipeline capacity at the full tariff rate. This is consistent with the established precedent on the wholesale core ITCS issue in D.95-12-053.

63. SDG&E and Long Beach obtain their capacity at market prices and should assume cost responsibility for their share of the ITCS, including the amortization of the accumulated balance in the ITCS account. Should Long Beach or SDG&E elect in the future to reserve interstate pipeline capacity from SoCalGas at 100% of the as-billed rate, SoCalGas should apply the 10% ITCS cost cap to the amount reserved for the period either wholesale customer maintains its capacity reservation.

64. The ITCS account balance on December 31, 1996 should be amortized over the full BCAP period. We find a sufficient record exists to change the methodology to recover ITCS charges on a forecast basis.

65. Noncore customers with their own firm capacity have no entitlement to receive special treatment or to be relieved from paying their share of SoCalGas' ITCS liability.

Cost of Gas

66. A one-time refund of the Purchased Gas Account (PGA) overcollection avoids distortions in the price signal sent to customers and is consistent with our policy objectives.

67. We should adopt SoCalGas' forecasts of a weighted average cost of gas of $1.62/Dth, $1.76/Dth, and $1.82/Dth for BCAP years 1, 2, and 3, respectively.

68. Hub net revenues should be used to lower the cost of gas to the core. We should adopt the SoCalGas/ORA settlement proposal for treatment of Hub revenues beginning April 1, 1997. Hub revenues received from April 1, 1995 to March 31, 1997 should be booked to the CFCA.

69. SoCalGas should continue to record producer exchange revenues that move as transport revenues at the previously-existing

contract rate; any incremental revenues should be recorded as noncore transport revenue.

70. SoCalGas' forecast of volumes and revenues for Interutility Exchange service between SoCalGas and PG&E under the Master Exchange Agreement and its Enhanced Oil Recovery forecast are reasonable and should be adopted.

71. We should adopt a core brokerage fee of $0.00201 per therm.

Audit Issues

72. We should adopt ORA's recommendation to credit the Fuel Cell Proceeds Memorandum Account by $103,000 and direct that the account remain open for the coming period.

73. The $768,000 in the Audit Expense account should not be recovered now; rather, the balance should be deferred until the audit is complete.

74. SoCalGas' forecast of a $469,000 overcollection in the Research, Royalty, and Memo Account is reasonable.

75. We should accept ORA's recommendation to defer recovery of approximately $2 million in the Catastrophic Event Memorandum Account (CEMA) account pending final disposition of ORA's audit report in A.94-12-006.

76. We adopt ORA's proposal to do an in-depth audit on the CFCA and ITCS accounts in November 1996 with a report filed by mid-January 1997, followed by an in-depth audit of the PITCO/POPCO account with a report filed March 1, 1997. Parties may file comments and a request for hearing four weeks after each report is filed.

Rate Design

77. The evidence supports an increase in the service establishment charge for SoCalGas' low-income CARE customers to $10; this discounted rate should be available for every hookup by these customers.

78. We should not alter the current 15 percent low-income discount structure for SoCalGas.

79. We should not adopt SoCalGas' proposal to cap the CARE surcharge.

80. SoCalGas should amortize the CARE forecasted balance of $29 million over the 31-month BCAP cycle.

81. Until the generic issues being explored by the new low-income Governing Board established by D.97-02-014 have been addressed, we should follow the existing CARE guidelines established in D.89-11-018 and allow SoCalGas to continue its practice of line itemization of the CARE surcharge on customer bills.

82. We should retain the current residential customer charge.

83. The tier differentials should be calculated on a composite basis.

84. SoCalGas should reduce its summer baseline quantity to 15 therms to comply with statutory guidelines; winter baseline should remain unchanged.

85. We should further deaverage core rates 50 percent in this proceeding.

86. We should not adopt E&S's proposal for residential segmentation in this proceeding.

87. We should adopt PLB's proposal to unbundle customer-related costs because it provides improved costs signals and a more accurate pricing methodology.

88. We should retain the two separate core commercial/industrial classes of G-10 and G-20 and their existing customer charges.

89. The Residual Load Service (RLS) tariff continues to be required in order to discourage bypass which would leave SoCalGas providing high-cost peak rate service at low tariffed rates to customers who partially bypass.

90. SoCalGas' changes to the method for calculating the pre- and post-bypass load factors for the purpose of calculating the default RLS tariff rate appear equitable and necessary in order to

allow the RLS tariff to function as intended; therefore, we should adopt the changes.

91. TURN's proposal of a noncore retail rate cap of 20% and a wholesale rate cap of 12.5%, applied to the cost of intrastate transportation without the ITCS component, is reasonable and should be adopted.

LRMC Methodology for SDG&E

92. SDG&E has not followed Commission directives in its resource plan filing to provide (a) an explicit noncore reliability standard and (b) a core service reliability study that documents the value its core customers place on peak service reliability.

93. The magnitude of change that has occurred in SDG&E's long-term forecast since its last BCAP needs to be further reviewed. The schedule of a normal BCAP is not sufficient to adequately review the long-term demand forecast and other components of the resource plan.

94. Rather than requiring SDG&E to refile its entire resource plan, we instead direct it to provide the missing elements. SDG&E should file its completed plan within six months of this order.

95. A prehearing conference should be scheduled 60 days after SDG&E's filing to set a procedural schedule for addressing the filing.

96. SDG&E's proposal to use a beginning date of 1997 for its resource plan is a deviation from existing methodology. We should adopt ORA's calculation of a $56.3 million resource plan.

97. We should not adopt the replacement cost adder as a refinement to SDG&E's LRMC methodology.

98. SDG&E provides no new evidence to support its proposal to change its local transmission MDM and its proposal to change the allocator for SoCalGas' system costs is not persuasive. Therefore, we should retain the existing cost allocators.

99. SDG&E provides no new evidence to support its proposal to change the methodology for estimating the marginal cost of

transmission capital investments; therefore, we should retain our existing Total Investment Methodology.

100. For the same reasons we eliminated a replacement adjustment for SoCalGas, we should eliminate the 25% adjustment to SDG&E's replacement cost for distribution mains and service.

101. Consistent with our finding for SoCalGas, we should adopt the NCO method for calculating SDG&E's marginal customer costs.

102. SDG&E fails to explain why its SRM engineering estimates produce such different values from its own budget forecasts and, further, why its estimated customer costs differ so greatly from those we adopt in this decision for SoCalGas; therefore, we adopt ORA's recommendation to apply a 25% reduction to SDG&E's SRM costs.

<u>SDG&E's Unbundling</u>

103. We should unbundle core interstate pipeline demand charges on SDG&E's system in this proceeding.

<u>Other Issues</u>

104. We should adopt for SDG&E cogeneration throughput a revised forecast of 451.8 million therms.

105. We should adopt a UEG forecast of 421 million therms per year.

106. We should adopt for SDG&E a core and noncore brokerage fee of $0.00092 per therm.

107. SDG&E's position that the Global Settlement Obligation be removed from rates immediately is reasonable and should be adopted. SDG&E may use the amount in the GSPTA to pay SoCalGas on a monthly basis. The GSPTA should remain open until further notice by this Commission, but any overcollection as a result of the disposition of the Global Settlement obligation should be timely refunded to ratepayers by advice letter filing. Any undercollection will be addressed in the next BCAP, or the appropriate proceeding noted in the procedural roadmap issued following our Natural Gas Strategy.

108. ORA did not perform an audit of any SDG&E accounts for this proceeding.

109. We find ORA's audit plan reasonable and should adopt it.

110. We should adopt ORA's proposal of a tier differential of 1.25 to 1.00.

Rate Design

111. It is reasonable to use the level of deaveraging incorporated in SDG&E's original filing and to allocate 70% of the core decrease to the core commercial class.

112. SDG&E's proposal to make the following changes to GA-1 and GA-2 schedules is reasonable:

1. For Schedule GN-1:

   (a) Lower the applicability of the amount of gas billed at the Tier 1 rate from 3,000 to 1,000 therms per month; and

   (b) To the extent that there is a decrease for this customer group, allocate the decrease to the Tier 1 rate.

2. For Schedule GN-2:

   (a) Increase the applicability of the amount of gas billed at the Tier 1 rate from 3,000 to 6,000 therms per month; and

   (b) Increase the customer charge from $60 to $75 per month.

113. We should adopt SDG&E's proposal for transmission level service because it is consistent with our principle of allocating costs to those customers who cause them.

114. We should retain the existing UEG rate design.

115. We should not expand the service eligibility for Schedule XGTS. We should keep Schedule XGTS for the BCAP period with the requirement that SDG&E shareholders will be at risk for 25% of the future revenue shortfall. We should adopt SDG&E's proposal for the calculation of off-peak allowances.

116. We should adopt ORA's recommendation to eliminate the Schedule XGSR tariff. SDG&E should work with ORA, TURN, and other interested parties to develop alternative residential programs.

117. We find the joint recommendation for a 4% reduction to SDG&E's existing Average Full Service LNG Rate reasonable.

118. We should adopt the same cogeneration parity proposal for SDG&E as adopted for SoCalGas.

119. We should adopt the following SDG&E proposals:

- Simplification of its gas procurement tariffs for noncore customers.
- Proposed revisions to its Gas Rule 14, rules and procedures for gas curtailment.
- Add a separate line item to its noncore gas transportation tariffs to reflect recovery of Wheeler Ridge access fees.

Conclusions of Law

1. SDG&E should not defer collection of its regulatory balances.

2. The core's occasional use of noncore capacity on extreme peak days is consistent with the language adopted by the Commission in D.91-11-025 on the provisions for voluntary and involuntary noncore diversions.

3. SoCalGas should file an advice letter within 10 days (1) reconciling by month, beginning with January 1, 1995, its expansion contracts to the operating capacity at its expansion facilities and (2) crediting back any revenues from storage contracts in excess of its expansion capacity to the Storage Transition Cost account.

4. The time for a review of the LRMC methodology is in our Natural Gas Strategy.

5. Adoption of a replacement cost adder for SoCalGas violates the standards set forth in the Global Settlement.

6. It is the rate paid by the UEGs, not the tariff rate, which is the subject of Public Utilities Code § 454.4. To comply with § 454.4, a utility cannot ignore discounts offered to UEGs when establishing gas rates for cogenerators.

7. Section 454.4 requires that when a UEG enters into a nonvolumetric contract with a gas utility, cogenerators must be allowed to enter into similar agreements.

8. The public interest in the confidentiality of contracts between the utility and all electricity generators outweighs the public interest served by disclosure.

9. SoCalGas should file by advice letter redacted versions of all discount contracts with utility electric generators and provide the full contracts and supporting workpapers to the Energy Division and to all SoCalGas customers that execute an appropriate confidentiality agreement.

10. The revenue requirement, revenue and cost allocations, and rate changes adopted for SoCalGas are set forth in Appendices B and D.

11. The revenue requirement, revenue and cost allocations, and rate changes adopted for SDG&E are set forth in Appendices C, E, and F.

O R D E R

IT IS ORDERED that:

1. We hereby adopt the changes to Long-Run Marginal Cost (LRMC) methodology, storage cost allocation, interstate pipeline capacity cost allocation, and rate design for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) as set forth in the discussion, findings, and conclusions of this decision.

2. SoCalGas shall file, on or after the effective date of this order, and at least three days prior to their effective date,

revised tariff schedules which implement the adopted changes shown in Appendix B. The revised tariff schedules shall comply with General Order (GO) 96-A and shall apply to service rendered on or after their effective date.

3. SDG&E shall file, on or after the effective date of this order, and at least three days prior to their effective date, revised tariff schedules which implement the adopted changes shown in Appendix C. The revised tariff schedules shall comply with GO 96-A and shall apply to service rendered on or after their effective date.

4. The record is reopened for the limited purpose of entering Exhibit 124 into evidence.

5. Following the issuance of our Natural Gas Strategy, the Executive Director shall direct staff to develop a procedural roadmap to address the following natural gas issues as set forth in detail in the text of this decision:

a. A study of storage operations including the cost-effectiveness of withdrawal reservations, a definition of firm injection service, and a study of load balancing injection capacity.

b. A review of LRMC and resource planning issues as proposed by ORA in this proceeding and discussed in the LRMC section of this decision.

c. The appropriateness of maintaining a core reservation.

d. An analysis of the full cost and cost allocation ramifications of three alternative reliability standards as proposed by TURN and discussed in the LRMC/core peak day reliability section of this decision.

e. A customer classification study as discussed in the SoCalGas/core deaveraging portion of this decision.

f. Consideration of Global Settlement undercollections, if any, for SDG&E.

g. A review of potential real-time pricing schedules as discussed in the SDG&E/Schedule XGTS portion of this decision.

6. SoCalGas shall file an advice letter within 20 days showing (a) how past savings resulting from the zone rate credit limitation have been or will be returned to ratepayers; and (b) a plan to implement the offering of non-volumetric discount gas transportation contracts to cogenerators on similar terms and conditions as those offered to UEGs.

7. Within 30 days of the effective date of this decision, SoCalGas shall file by advice letter a one-time refund plan to be effective as soon as possible. The refund plan shall use the latest actual balance in the Purchased Gas Account in making the refund calculation. If the actual balance in the Purchased Gas Account is undercollected, SoCalGas shall immediately file in this docket, not by advice letter filing, a proposal to collect this balance.

8. SDG&E shall file an advice letter establishing an Interstate Transition Cost Surcharge balancing account to track the differential between its actual brokered capacity cost and the above market cost of its reservation of firm capacity on the El Paso Natural Gas Company transmission line on a monthly basis. SDG&E shall include in this advice letter filing the establishment of an initial surcharge to collect in rates from all core customers the cost differential between its brokered capacity costs and its El Paso above-market firm capacity costs. This initial surcharge shall be updated by advice letter whenever the unrecovered balance would result in the surcharge changing by 10% or more on a sustained basis.

9. The assigned Administrative Law Judge shall schedule a workshop within 60 days of the effective date of this order for the purpose of (1) developing a voluntary capacity assignment mechanism for SoCalGas that is consistent with FERC rules; and (2) considering whether to eliminate SoCalGas' minimum bid procedures.

10. SDG&E shall file a completed resource plan within six months of this order. The assigned Administrative Law Judge shall

schedule a prehearing conference 60 days after SDG&E's fling to set a procedural schedule.

This order is effective today.

Dated April 23, 1997, Francisco, California.

JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

I will file a dissent.

/s/ P. GREGORY CONLON
President

MASTER NOTICE LIST
A96-04-030/A96-03-031
CRTD: REH-4/12/96 REV: 1/22/97 bnk
CORR: 1/22/97 bnk
Doc. I.D. F10992

APPENDIX A
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(END OF APPENDIX A)

APPENDIX B
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Knight - Alternate Decision

SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF REVENUE CHANGES

	REVENUES AT PRESENT RATES (M$)	REVENUES AT PROPOSED RATES (M$)	INCREASE (DECREASE) (M$)	CHANGE (%)
	(A)	(B)	(C=B-A)	(D=C/A)
CORE SALES:				
RESIDENTIAL	1,766,427	1,802,952	36,525	2.068
G-10	390,823	370,258	(20,565)	(5.262)
G-20	15,397	16,085	688	4.465
GAS A/C	1,354	1,573	220	16.234
GAS ENGINE	6,306	9,095	2,789	44.231
TOTAL CORE SALES	2,180,307	2,199,964	19,657	0.902
CORE TRANSPORTATION:				
RESIDENTIAL	25,860	26,243	382	1.478
G-10	74,685	67,940	(6,745)	(9.032)
G-20	1,117	1,175	58	5.191
GAS A/C	0	0	0	0.000
GAS ENGINE	1,315	2,396	1,080	82.122
SUBTOTAL CORE TRANSPORTATION	102,978	97,753	(5,225)	(5.074)
TOTAL CORE	2,283,285	2,297,717	14,432	0.632
NONCORE:				
INDUSTRIAL	94,889	97,234	2,345	2.471
UEG	105,441	97,584	(7,858)	(7.452)
COGEN	43,718	40,460	(3,258)	(7.452)
NONCORE SUBTOTAL	244,048	235,277	(8,771)	(3.594)
WHOLESALE				
LONG BEACH	3,599	4,568	969	26.920
SAN DIEGO GAS & ELECTRIC	52,550	52,084	(466)	(0.886)
SOUTHWEST	4,774	5,536	761	15.947
TOTAL WHOLESALE	60,924	62,188	1,265	2.076
UNBUNDLED STORAGE	23,925	20,576	(3,349)	(13.997)
ZONE RATE CREDIT	(7,120)	(8,034)	(914)	12.836
NET CARE REVENUES	879	879	0	0.000
SYSTEM TOTAL	2,605,941	2,608,604	2,663	0.102
TOTAL CARE REVENUES	30,646	51,584	20,938	68.322
EOR REVENUES	33,407	32,616	(791)	(2.369)

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SOUTHERN CALIFORNIA GAS COMPANY
RESIDENTIAL MASTER-METER RATE SEGMENTATION

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Core Customer Class	Throughput	Present Rates Rate	Present Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue
	(Mth)	($/th)	($M)	($/th)	($M)
(A)	(B)	(C)	(D)	(E)	(F)
				Knight - Alternate Decision	
CORE SALES RATES					
RESIDENTIAL					
Customer Charge		$5.00	259,291		
Single Family				$5.00	169,920
Multi-Family Family				$5.00	86,759
Master Metered				$5.00	2,612
Submeter Credit			(2,131)		(11,272)
Tier I Volumetric	1,731,459	0.50867	880,743	0.53277	922,474
Tier II Volumetric	870,316	0.68671	597,651	0.71924	625,969
Subtotal	2,601,774	0.66707	1,735,555	0.69048	1,796,463
LARGE MASTER-METER					
Customer Charge	21	$5.00	1	582.61	148
Tier I Volumetric	7,807	0.50867	3,971	0.40360	3,151
Tier II Volumetric	5,855	0.68671	4,021	0.54487	3,190
Subtotal	13,662	0.58507	7,993	0.47500	6,490
CORE TRANSPORTATION RATES					
RESIDENTIAL					
Customer Charge		5.00	5,118		
Single Family				$5.00	3,354
Multi-Family Family				$5.00	1,712
Master Metered				$5.00	52
Submeter Credit			(42)		(222)
Tier I Volumetric	34,176	0.33423	11,422	0.35177	12,022
Tier II Volumetric	17,178	0.51226	8,800	0.53824	9,246
Subtotal	51,354	0.49262	25,298	0.50947	26,163
LARGE MASTER-METER					
Customer Charge	0	$5.00	0.03	582.81	2
Tier I Volumetric	154	0.33423	52	0.22260	34
Tier II Volumetric	116	0.51226	59	0.36386	42
Subtotal	270	0.41062	111	0.29219	79

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SOUTHERN CALIFORNIA GAS COMPANY

PRESENT AND PROPOSED CORE TRANSPORTATION RATES

Core Customer Class	Throughput	Present Rates Rate	Present Rates Revenue	Proposed Rates Rate	Proposed Rates Revenue
	(Mth)	($/th)	($M)	($/th)	($M)
(A)	(B)	(C)	(D)	(E)	(F)
				Knight - Alternate Decision	
CORE TRANSPORTATION RATES					
RESIDENTIAL					
Customer Charge		5.00	5,118		
Single Family				$5.00	3,354
Multi-Family Family				$5.00	1,712
Master Metered				$5.00	54
Submeter Credit			(42)		(222)
Tier I Volumetric	34,330	0.33423	11,474	0.35107	12,052
Tier II Volumetric	17,294	0.51226	8,859	0.53730	9,292
Subtotal Residential	51,624	0.49219	25,409	0.50835	26,243
G-10					
Customer Charge	46,027	$15.00	8,291	$15.00	8,285
Tier I Volumetric [1]	36,593	0.60247	22,046	0.60583	22,169
Tier II Volumetric	109,648	0.32011	35,100	0.29520	32,369
Tier III Volumetric	32,622	0.32011	10,443	0.15689	5,118
Subtotal G-10	178,862	0.42423	75,880	0.37985	67,940
G-20					
Customer Charge	4	$350.00	61	$350.00	18
Tier I Volumetric	1,696	0.16347	277	0.22834	387
Tier II Volumetric	4,905	0.16347	802	0.15689	770
Subtotal G-20	6,601	0.17278	1,141	0.17795	1,175
NON-RES GAS A/C					
Customer Charge		$150.00	0	$150.00	0
Volumetric	0	0.14224	0	0.19592	0
Subtotal Non-Res Gas A/C	0	0.17263	0	0.22241	0
GAS ENGINES					
Customer Charge		$50.00	184	$50.00	184
Volumetric	7,060	0.16017	1,131	0.31323	2,211
Subtotal Gas Engines	7,060	0.18631	1,315	0.33932	2,396
TOTAL CORE CARE SURCHARGE					
Previous BCAP	3,468,302	0.00884	30,646		
1996 BCAP	3,258,759			0.01151	37,500

[1] Tier I quantity equals first 250 therms per month in December - March, and first 100 therms per month in April - November.

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SOUTHERN CALIFORNIA GAS COMPANY

TABLE C.6: PRESENT AND PROPOSED NONCORE RATES

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Noncore Customer Class	Throughput (Mth)	Present Rates Rate ($/th)	Present Rates Revenue ($M)	Proposed Rates Rate ($/th)	Proposed Rates Revenue ($M)
(A)	(B)	(C)	(D)	(F)	(G)
RETAIL					
INDUSTRIAL G-30					
TRANSPORTATION RATES	1,223,933	0.05949	72,811	0.06644	81,321
ITCS	1,223,933	0.01804	22,078	0.01300	15,913
TOTAL	1,223,933	0.07753	94,889	0.07944	97,234
CARE SURCHARGE Present	1,223,933	0.00884	10,815		
CARE SURCHARGE Proposed	1,223,933			0.01151	14,084
UTILITY ELECTRIC GENERATION (UEG)					
VOLUMETRIC RATE	1,989,390	0.03496	69,555	0.03605	71,719
ITCS	1,989,390	0.01804	35,886	0.01300	25,865
TOTAL	1,989,390	0.05300	105,441	0.04905	97,584
COGENERATION					
VOLUMETRIC RATE	824,830	0.03496	28,838	0.03605	29,736
ITCS	824,830	0.01804	14,879	0.01300	10,724
TOTAL	824,830	0.05300	43,718	0.04905	40,460
WHOLESALE					
LONG BEACH					
STORAGE CHARGE			925		1,087
VOLUMETRIC RATE	65,100	0.03801	2,474	0.04054	2,639
ITCS	65,100	0.00784	510	0.01294	842
TOTAL	65,100	0.05529	3,599	0.07017	4,568
SDG&E					
STORAGE CHARGE			7,702		6,875
ALL VOLUMETRIC RATE	1,082,910	0.02987	32,344	0.02881	31,195
ITCS	1,082,910	0.01155	12,504	0.01294	14,014
TOTAL	1,082,910	0.04853	52,550	0.04810	52,084
SOUTHWEST GAS					
STORAGE CHARGE			1,558		1,504
TRANSPORTATION RATES	86,916	0.03168	2,754	0.03344	2,907
ITCS	86,916	0.00532	463	0.01294	1,125
TOTAL	86,916	0.05493	4,774	0.06369	5,536
BROKERAGE FEES	283,284	0.00266	754	0.00266	754
ZONE RATE CREDIT	1,928,824	(0.00355)	(6,857)	(0.00417)	(8,034)

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SOUTHERN CALIFORNIA GAS COMPANY

PRESENT AND ADOPTED NONCORE INDUSTRIAL (G-30) SEGMENTED RATES

Knight - Alternate Decision

			Present Rates					Proposed Rates				
Segmentat	Number Of Cust	Throughput (Mth)	Cust. Chg. ($/mo)	Vol. Chg. ($/th)	Cust. Chg. Revenues (M$)	Volumetric Revenues (M$)	Total Revenues (M$)	Cust. Chg. ($/mo)	Vol. Chg. ($/th)	Cust. Chg. Revenues (M$)	Volumetric Revenues (M$)	Total Revenues (M$)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
MEDIUM PRESSURE (Mdth)												
0 - 25	151	24,635	50	0.17355	91	4,275	4,366	150	0.12529	272	3,086	3,359
25-100	459	368,595	800	0.08747	4,403	32,243	36,646	800	0.07587	4,403	27,966	32,369
>100	69	156,494	1,200	0.08090	994	12,661	13,655	1,200	0.06938	994	10,858	11,852
Total	679	549,725			5,488	49,177	54,665			5,669	41,911	47,580
HIGH PRESSURE (Mdth)												
0 - 25	113	6,307	50	0.14375	68	907	974	150	0.08400	203	530	732
25-100	111	51,100	800	0.04506	1,062	2,303	3,365	800	0.05427	1,062	2,773	3,835
100-200	55	63,322	1,200	0.03993	790	2,528	3,318	1,200	0.04383	790	2,775	3,565
>200	116	506,223	1,800	0.03901	2,512	19,750	22,262	1,800	0.04130	2,512	20,906	23,418
Total	394	626,952			4,432	25,486	29,918			4,567	26,984	31,551
TRANSMISSION (Mdth)												
0-200	15	12,200	1,200	0.03853	218	470	688	1,200	0.04126	218	503	721
>200	8	35,056	1,800	0.03269	163	1,146	1,310	1,800	0.03724	163	1,306	1,469
Total	23	47,257			381	1,616	1,997			381	1,809	2,190
Total Noncore Industrial	1,096	1,223,933		0.07074	10,301	76,279	86,580		0.06644	10,617	70,704	81,321
I. T. C. S.				0.01804					0.01300			

APPENDIX B
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SOUTHERN CALIFORNIA GAS COMPANY

UNBUNDLED STORAGE RATES FOR EXISTING FACILITIES
Knight - Alternate Decision

	INJECTION	WITHDRAWAL	INVENTORY
	$/Mcfd	$/Mcfd	$/Mcf
MARGINAL COST	21.499	13.067	0.183
SCALING	16.85%	16.85%	16.85%
TOTAL ALLOCATED MARGIN	25.123	15.269	0.214
MARKETING COSTS	0.000	0.066	0.001
TARIFF RESERVATION RATE	25.123	15.336	0.215
	$/Dth/d	$/Dth/d	$/Dth
TARIFF RESERVATION RATE	24.156	14.746	0.207
DAILY INJECTION RATE	0.11740		
VARIABLE RATE, $/Dth	0.03377	0.02622	NA

(END OF APPENDIX B)

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SAN DIEGO GAS & ELECTRIC
1996 Biennial Cost Allocation Proceeding

GAS REVENUE ALLOCATION SUMMARY
By Customer Class
Effective January 1, 1997

				At Present Rates		At Proposed Rates		Changes		
			Proposed Volumes	Revenues	Average Rate	Revenues	Average Rate	Revenues	Rates	Percent
			A	D	E	G	H			
			mtherms	*$1000*	*c/therm*	*$1000*	*c/therm*	*$1000*	*c/therm*	
1	Residential	1/	340,731	$221,464	64.997	$216,046	63.406	($5,418)	-1.590	-2.4%
2	Small Commercial	1/	119,060	$70,059	58.844	$65,359	54.896	($4,700)	-3.948	-6.7%
3	Large Commercial	1/	10,609	$4,074	38.403	$3,726	35.126	($348)	-3.278	-8.5%
4										
5	**Total CORE**		470,400	$295,597	62.840	$285,131	60.615	($10,466)	-2.225	-3.5%
6										
7	Commercial/Industrial	1/	102,228	$27,787	27.182	$21,682	21.209	($6,105)	-5.972	-22.0%
8	Cogeneration	1,2/	135,067	$16,865	12.487	$12,317	9.119	($4,548)	-3.367	-27.0%
9	UEG	2/	421,296	$104,769	24.868	$100,239	23.793	($4,530)	-1.075	-4.3%
10										
11	**Total NONCORE**		658,591	$149,422	22.688	$134,238	20.383	($15,184)	-2.305	-10.2%
12										
13	RATE RECOVERY		1,128,991	$445,019	39.417	$419,369	37.145	($25,650)	-2.272	-5.8%
14	+ Miscellaneous Revenues			$2,804		$2,804		$0		
15										
16	GAS REVENUE REQUIREMENTS		1,128,991	$447,823		$422,173		($25,650)		-5.7%

Notes 1/ Includes transportation-only charges for customers who procure their own gas supplies. As such, these average rates exclude the purchase price of gas for transport-only customers.

2/ In accordance with CPUC Code 254.4, the proposed average rates for gas services offered to cogeneration and UEG customers are the same. Any differences in average rates between cogeneration and UEG customers reflect differences in gas service elections.

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SAN DIEGO GAS & ELECTRIC
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SUMMARY OF CORE RATES

	CUSTOMER GROUP	Units	Present Rates	Proposed Rates	Rate Change	%Change	
		A	B	C	D	E	
			1/				
1	**RESIDENTIAL:** *Schedules GR, GM, GS, GT*						1
2	Regular Baseline	C/therm	59.501	59.332	-0.169	-0.3%	2
3	Regular Non-Baseline 100%	C/therm	81.926	75.851	-6.075	-7.4%	3
4	Average Full Service Rate	C/therm	66.499	64.487	-2.012	-3.0%	4
5	NBL/BL Difference	C/therm	22.425	16.519	-5.906		5
6	NBL/BL Ratio		1.377	1.278			6
7							7
8	CARE Baseline	C/therm	48.724	50.056	1.332	2.7%	8
9	CARE Non-Baseline	C/therm	67.786	64.097	-3.689	-5.4%	9
10	CARE Surcharge	C/therm	0.612	0.443	-0.169		10
11							11
12	GS Unit Discount	C/day	-6.200	-6.200	0.000	0.0%	12
13	GT Unit Discount	C/day	-19.700	-19.700	0.000	0.0%	13
14							14
15	LNG Facility Charge *Schedule GL-1:*	$/month	$14.31	$13.59	($0.72)	-5.0%	15
16	LNG Volumetric Surcharge	C/therm	16.034	15.232	-0.802	-5.0%	16
17	Average Full Service LNG Rate	C/therm	130.244	125.035	-5.210	-4.0%	17
18							18
19							19
20	**CORE COMMERCIAL:** *Schedules GN-1 & GN-2*						20
21	GN-1 Present Proposed	$/month	$5.00	$5.00	$0.00	0.0%	21
22	Winter 1st 3000 1st 1000 therms	C/therm	72.289	74.551	2.262	3.1%	22
23	All excess All excess	C/therm	40.969	40.969	0.000	0.0%	23
24		Ratio	1.764	1.820			24
25							25
26	Summer 1st 3000 1st 1000 therms	C/therm	61.208	63.074	1.865	3.0%	26
27	All excess All excess	C/therm	40.310	40.310	0.000	0.0%	27
28		Ratio	1.518	1.565			28
29	Average Full Service Rate	C/therm	60.963	62.495	1.532	2.5%	29
30							30
31	GN-2 Present Proposed	$/month	$60	$75	$15	25.0%	31
32	Winter 1st 3000 1st 6000 therms	C/therm	72.289	63.595	-8.694	-12.0%	32
33	All excess All excess	C/therm	40.969	36.042	-4.927	-12.0%	33
34		Ratio	1.764	1.764			34
35							35
36	Summer 1st 3000 1st 6000 therms	C/therm	57.944	50.976	-6.969	-12.0%	36
37	All excess All excess	C/therm	38.090	33.509	-4.581	-12.0%	37
38		Ratio	1.521	1.521			38
39	Average Full Service Rate	C/therm	40.925	36.048	-4.877	-11.9%	39
40							40
41	NGV Bus Fleets *Schedule G-NGV*	C/therm	53.976	65.163	11.186	20.7%	41
42	Other	C/therm	75.976	91.722	15.746	20.7%	42
43	Uncompressed Gas	C/therm	37.476	34.679	-2.797	-7.5%	43
44	Co-Funded	C/therm	56.726	52.098	-4.628	-8.2%	44

Notes: 1/ Present Rates reflect monthly changing procurement prices in effect by year-end 1996.

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SAN DIEGO GAS & ELECTRIC

1996 Biennial Cost Allocation Proceeding

SUMMARY OF CORE TRANSPORTATION-ONLY RATES

	CUSTOMER GROUP	Units	Present Rates	Proposed Rates	Rate Change	%Change	
		A	B	C	D	E	
1	**RESIDENTIAL:** *Schedules GTC & GTCA*						1
2	Regular Baseline	C/therm	43.149	42.980	-0.169	-0.4%	2
3	Regular Non-Baseline	C/therm	65.574	59.499	-6.075	-9.3%	3
4							4
5	CARE Baseline	C/therm	32.373	33.704	1.331	4.1%	5
6	CARE Non-Baseline	C/therm	51.434	47.745	-3.689	-7.2%	6
7							7
8	**CORE COMMERCIAL:**						8
9	GN-1 Present Proposed	$/month	$5.00	$5.00	$0.00	0.0%	9
10	Winter 1st 3000 1st 1000 therms	C/therm	55.937	58.199	2.262	4.0%	10
11	All excess All excess	C/therm	24.617	24.617	0.000	0.0%	11
12							12
13	Summe 1st 3000 1st 1000 therms	C/therm	44.857	46.721	1.864	4.2%	13
14	All excess All excess	C/therm	23.958	23.958	-0.000	-0.0%	14
15							15
16	GN-2 Service Charge	$/month	$60	$75	$15	25.0%	16
17	Winter 1st 3000 1st 6000 therms	C/therm	55.937	47.243	-8.694	-15.5%	17
18	All excess All excess	C/therm	24.617	19.690	-4.927	-20.0%	18
19							19
20	Summe 1st 3000 1st 6000 therms	C/therm	41.592	34.623	-6.969	-16.8%	20
21	All excess All excess	C/therm	21.738	17.157	-4.581	-21.1%	21
22							22
23	GT-NGV Uncompressed Gas	C/therm	10.341	16.682	6.341	61.3%	23
24							24
25							25
26	**OTHER CORE RATES:**						26
27	CPGA Rate Adder	C/therm	0.000	0.000	0.000		27
28	CORE Procurement Rate 1/	C/therm	16.352	16.352	0.000	0.0%	28
29	CORE Interstate Pipeline Demand Charge	C/therm	3.237	1.536	-1.701	-52.5%	29

Notes 1/ Present Rates reflect monthly changing procurement prices in effect by year-end 1996.

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TYPICAL MONTHLY BILLS
Residential Customers

	Monthly Energy Usage	Present Bill	Proposed Bill	Change	%Change	
	A	B	C	D	E	
	therms	$1	$1	$1		
1	0	$0.00	$0.00	$0.00	0.0%	1
2	5	$2.98	$2.97	($0.01)	-0.3%	2
3	10	$5.96	$5.94	($0.02)	-0.3%	3
4	15	$8.94	$8.91	($0.03)	-0.3%	4
5	20	$12.27	$12.14	($0.13)	-1.0%	5
6	25	$15.81	$15.53	($0.28)	-1.8%	6
7	30	$19.35	$18.91	($0.44)	-2.3%	7
8	35	$22.89	$22.29	($0.60)	-2.6%	8
9						9
10	***40***	***$26.43***	***$25.68***	***($0.75)***	***-2.8%***	***10***
11						11
12	45	$30.16	$29.20	($0.96)	-3.2%	12
13	50	$34.26	$33.00	($1.26)	-3.7%	13
14	55	$38.36	$36.79	($1.57)	-4.1%	14
15	60	$42.46	$40.59	($1.87)	-4.4%	15
16	65	$46.56	$44.39	($2.17)	-4.7%	16
17	70	$50.66	$48.18	($2.48)	-4.9%	17
18	75	$54.76	$51.98	($2.78)	-5.1%	18
19	80	$58.86	$55.78	($3.08)	-5.2%	19
20	85	$62.96	$59.57	($3.39)	-5.4%	20
21	90	$67.06	$63.37	($3.69)	-5.5%	21
22	95	$71.16	$67.16	($4.00)	-5.6%	22
23	100	$75.26	$70.96	($4.30)	-5.7%	23
24	125	$95.76	$89.94	($5.82)	-6.1%	24
25	150	$116.26	$108.92	($7.34)	-6.3%	25
26	200	$157.26	$146.89	($10.37)	-6.6%	26
27	300	$239.27	$222.82	($16.45)	-6.9%	27
28	400	$321.27	$298.74	($22.52)	-7.0%	28
29	500	$403.27	$374.67	($28.60)	-7.1%	29
30	1,000	$813.28	$754.31	($58.98)	-7.3%	30
31	2,000	$1,633.31	$1,513.58	($119.73)	-7.3%	31

Notes *All typical bills in this table include CPUC regulatory surcharges.*
Present bill calculations reflect monthly changing procurement prices in effect by year-end 1996.
Italics & bold item reflects the overall typical bill for this customer group

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SAN DIEGO GAS & ELECTRIC

1996 Biennial Cost Allocation Proceeding

SUMMARY OF CORE SUBSCRIPTION RATES

Bundled Gas Service for Noncore Customers

	CUSTOMER GROUP				Units	Present Rates	Proposed Rates	Rate Change	%Change	
					A	B	C	E	F	
						0 278	0 000	(B - C)		
1	COMMERCIAL/INDUSTRIAL			*Schedule GCORE*						1
2	Volumetric	MPS	Winter		C/therm	21.717	11.392	-10.325	-47.5%	2
3	Charges		Summer		C/therm	17.575	9.191	-8.384	-47.7%	3
4					Ratio	1.236	1.239			4
5										5
6		HPS	Winter		C/therm	12.823	7.811	-5.012	-39.1%	6
7			Summer		C/therm	10.146	6.144	-4.002	-39.4%	7
8					Ratio	1.264	1.271			8
9										9
10		Transm	Winter		C/therm	n/a	6.765			10
11			Summer		C/therm	n/a	5.384			11
12					Ratio		1.255			12
13	Customer Charges:			*all service levels*						13
14	0 to	3,000	therms		$/month	$13	$16	$3	25.0%	14
15	3,001 to	7,000	therms		$/month	$66	$83	$17	25.0%	15
16	7,001 to	23,000	therms		$/month	$121	$151	$30	25.0%	16
17	23,001 to	126,000	therms		$/month	$242	$303	$61	25.0%	17
18	126,001 to	1,000,000	therms		$/month	$486	$608	$122	25.0%	18
19	Over	1,000,000	therms		$/month	$1,032	$1,290	$258	25.0%	19
20										20
21	AMR Charges			*all service levels*	$/month	$100	$100	$0	0.0%	21
22										22
23	AVERAGE TARIFF RATE				C/therm	15.043	8.560	-6.483	-43.1%	23
24										24
25	COGENERATION			*Schedule GCORE*						25
26	Volumetric	Transm	Winter		C/therm	11.266	6.765	-4.511	-40.0%	26
27	Charges		Summer		C/therm	9.036	5.384	-3.652	-40.4%	27
28					Ratio	1.247	1.255			28
29										29
30		Other	Winter		C/therm	11.266	7.476	-3.790	-33.6%	30
31			Summer		C/therm	9.036	5.959	-3.077	-34.1%	31
32					Ratio	1.247	1.255			32
33	Customer Charges:			*all service levels*						33
34	0 to	3,000	therms		$/month	$18	$23	$5	25.0%	34
35	3,001 to	7,000	therms		$/month	$98	$123	$25	25.0%	35
36	7,001 to	23,000	therms		$/month	$180	$225	$45	25.0%	36
37	23,001 to	126,000	therms		$/month	$360	$450	$90	25.0%	37
38	126,001 to	1,000,000	therms		$/month	$720	$900	$180	25.0%	38
39	Over	1,000,000	therms		$/month	$1,529	$1,911	$382	25.0%	39
40										40
41	AMR Charges			*all service levels*	$/month	$100	$100	$0	0.0%	41
42										42
43	AVERAGE TARIFF RATE				C/therm	10.006	6.283	-3.723	-37.2%	43
44										44
45	UTILITY ELECTRIC GENERATION			*Schedule GCORE*						45
46	Demand Charges				$1/month	$1,780	$1,448	($332)	-18.6%	46
47	Volumetric Charges:	Igniter Fuel			C/therm	22.209	19.414	-2.795	-12.6%	47
48		Tier 1			C/therm	4.979	3.825	-1.154	-23.2%	48
49		Tier 2			C/therm	2.336	1.674	-0.662	-28.3%	49
50										50
51	AVERAGE TARIFF RATE				C/therm	7.991	6.283	-1.708	-21.4%	51

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SUMMARY OF BUNDLED NONCORE TRANSPORTATION RATES
Bundled Intrastate Transportation Service without Storage

	CUSTOMER GROUP	Units	Present Rates	Proposed Rates	Rate Change	%Change	
		A	B	C	E	F	
					(B - C)		
1	COMMERCIAL/INDUSTRIAL: *Schedule GTNC*						1
2	Volumetric MPS Winter	C/therm	21.439	11.392	-10.047	-46.9%	2
3	Charges Summer	C/therm	17.297	9.191	-8.106	-46.9%	3
4		Ratio	1.239	1.239			4
5							5
6	HPS Winter	C/therm	12.545	7.811	-4.734	-37.7%	6
7	Summer	C/therm	9.868	6.144	-3.724	-37.7%	7
8		Ratio	1.271	1.271			8
9							9
10	Transm Winter	C/therm	n/a	6.755			10
11	Summer	C/therm	n/a	5.384			11
12		Ratio		1.255			12
13	Customer Charges						13
14	0 to 3,000 therms	$/month	$13	$16	$3	25.0%	14
15	3,001 to 7,000 therms	$/month	$66	$83	$17	25.0%	15
16	7,001 to 23,000 therms	$/month	$121	$151	$30	25.0%	16
17	23,001 to 126,000 therms	$/month	$242	$303	$61	25.0%	17
18	126,001 to 1,000,000 therms	$/month	$486	$608	$122	25.0%	18
19	Over 1,000,000 therms	$/month	$1,032	$1,290	$258	25.0%	19
20							20
21	AMR Charges	$/month	$100	$100	$0	0.0%	21
22							22
23	AVERAGE TARIFF RATE	C/therm	14.765	8.560	-6.205	-42.0%	23
24							24
25	COGENERATION *Schedule GTCG*						25
26	Volumetric Transm Winter	C/therm	10.988	6.755	-4.233	-38.5%	26
27	Charges Summer	C/therm	8.758	5.384	-3.374	-38.5%	27
28		Ratio	1.255	1.255			28
29							29
30	Other Winter	C/therm	10.988	7.476	-3.512	-32.0%	30
31	Summer	C/therm	8.758	5.959	-2.799	-32.0%	31
32		Ratio	1.255	1.255			32
33	Customer Charges:						33
34	0 to 3,000 therms	$/month	$18	$23	$5	25.0%	34
35	3,001 to 7,000 therms	$/month	$98	$123	$25	25.0%	35
36	7,001 to 23,000 therms	$/month	$180	$225	$45	25.0%	36
37	23,001 to 126,000 therms	$/month	$360	$450	$90	25.0%	37
38	126,001 to 1,000,000 therms	$/month	$720	$900	$180	25.0%	38
39	Over 1,000,000 therms	$/month	$1,529	$1,911	$382	25.0%	39
40							40
41	AMR Charges	$/month	$100	$100	$0	0.0%	41
42							42
43	AVERAGE TARIFF RATE	C/therm	9.728	6.283	-3.445	-35.4%	43
44							44
45	UTILITY ELECTRIC GENERATION *Schedule GTUEG*						45
46	*Transmission-level service:*						46
47	Demand Charges	$1k/month	$1,780	$1,398	($382)	-21.4%	47
48	Volumetric Charges: Igniter Fuel	C/therm	21.931	19.414	-2.517	-11.5%	48
49	Tier 1	C/therm	4.701	3.704	-0.997	-21.2%	49
50	Tier 2	C/therm	2.058	1.621	-0.437	-21.2%	50
51							51
52	*All Other service:*						52
53	Demand Charges	$1k/month	$1,780	$50	($1,730)	-97.2%	53
54	Volumetric Charges: Igniter Fuel	C/therm	21.931	19.414	-2.517	-11.5%	54
55	Tier 1	C/therm	4.701	45.196	40.495	861.4%	55
56	Tier 2	C/therm	2.058	19.759	17.701	860.1%	56
57							57
58	AVERAGE TARIFF RATE	C/therm	7.713	6.283	-1.430	-18.5%	58
59							59
60	ITCS: INTERSTATE TRANSITION COST SURCHARGE	*(Embedded in the Volumetric Tariff Rates)*					60
61	Core ITCS Rate	C/therm	0.316	1.241	0.925	292.7%	61
62	Noncore ITCS Rate	C/therm	1.946	1.241	-0.705	-36.2%	62

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SAN DIEGO GAS & ELECTRIC

1996 Biennial Cost Allocation Proceeding

SUMMARY OF UNBUNDLED NONCORE TRANSPORTATION RATES

Unbundled Intrastate Transportation Service without Storage

	CUSTOMER GROUP		Units	Present Rates	Proposed Rates	Rate Change	%Change	
			A	B	C	E	F	
						(B - C)		
1	**ALL NONCORE**	Schedule GITS		*(Delivery across the SoCalGas pipeline system)*				1
2	Demand Charge, Coincident Peak-Month Usag		C/therm	2.285	2.003	-0.282	-12.3%	2
3	Volumetric Rate, Current Billing Period Usage		C/therm	3.049	1.010	-2.039	-66.9%	3
4								4
5	AVERAGE TARIFF RATE		C/therm	5.130	2.834			5
6								6
7	**COMMERCIAL/INDUSTRIAL**	Schedule GTNC-SD		*(Delivery across the SDG&E pipeline system)*				7
8	Volumetric MPS Winter		C/therm	15.618	8.557	-7.061	-45.2%	8
9	Charges Summer		C/therm	12.600	6.357	-6.243	-49.6%	9
10			Ratio	1.240	1.346			10
11								11
12	HPS Winter		C/therm	6.636	4.976	-1.660	-25.0%	12
13	Summer		C/therm	5.220	3.310	-1.910	-36.6%	13
14			Ratio	1.271	1.504			14
15								15
16	Trans Winter		C/therm	n/a	3.921			16
17	Summer		C/therm	n/a	2.550			17
18								18
19	Customer Charges:							19
20	0 to 3,000 therms		$/month	$13	$16	$3	25.0%	20
21	3,001 to 7,000 therms		$/month	$66	$83	$17	25.0%	21
22	7,001 to 23,000 therms		$/month	$121	$151	$30	25.0%	22
23	23,001 to 126,000 therms		$/month	$242	$303	$61	25.0%	23
24	126,001 to 1,000,000 therms		$/month	$486	$608	$122	25.0%	24
25	Over 1,000,000 therms		$/month	$1,032	$1,290	$258	25.0%	25
26								26
27	AMR Charges		$/month	$100	$100	$0	0.0%	27
28								28
29	AVERAGE TARIFF RATE		C/therm	9.635	5.725	-3.909	-40.6%	29
30								30
31	**COGENERATION**	Schedule GTCG-SD		*(Delivery across the SDG&E pipeline system)*				31
32	Volumetric Transm Winter		C/therm	5.112	3.921	-1.191	-23.3%	32
33	Charges Summer		C/therm	4.075	2.550	-1.525	-37.4%	33
34			Ratio	1.254	1.538			34
35								35
36	Other Winter		C/therm	5.112	4.642	-0.470	-9.2%	36
37	Summer		C/therm	4.075	3.124	-0.951	-23.3%	37
38			Ratio	1.254	1.486			38
39	Customer Charges:							39
40	0 to 3,000 therms		$/month	$18	$23	$5	25.0%	40
41	3,001 to 7,000 therms		$/month	$98	$123	$25	25.0%	41
42	7,001 to 23,000 therms		$/month	$180	$225	$45	25.0%	42
43	23,001 to 126,000 therms		$/month	$360	$450	$90	25.0%	43
44	126,001 to 1,000,000 therms		$/month	$720	$900	$180	25.0%	44
45	Over 1,000,000 therms		$/month	$1,529	$1,911	$382	25.0%	45
46								46
47	AMR Charges			$100	$100	$0	0.0%	47
48								48
49	AVERAGE TARIFF RATE		C/therm	4.598	3.449	-1.150	-25.0%	49
50								50
51	**UTILITY ELECTRIC GENERATION**	Schedule GTUEG-SD		*(Delivery across the SDG&E pipeline system)*				51
52	*Transmission-level service:*							52
53	Demand Charges		$1/month	$11,000	$9,397	($1,603)	-14.6%	53
54	Volumetric Charges: Igniter Fuel		C/therm	18.330	16.619	-1.711	-9.3%	54
55	Tier 1		C/therm	2.222	1.980	-0.242	-10.9%	55
56	Tier 2		C/therm	0.973	0.867	-0.106	-10.9%	56
57								57
58	*All Other service:*							58
59	Demand Charges		$1/month	$11,000	$603	($10,397)	-94.5%	59
60	Volumetric Charges: Igniter Fuel		C/therm	18.330	16.619	-1.711	-9.3%	60
61	Tier 1		C/therm	2.222	43.471	41.249	1856.4%	61
62	Tier 2		C/therm	0.973	19.004	18.031	1853.2%	62
63								63
64	AVERAGE TARIFF RATE		C/therm	2.583	3.449	0.866	33.5%	64

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1996 Biennial Cost Allocation Proceeding

SUMMARY OF NONCORE PROCUREMENT & STORAGE RATES

	CUSTOMER GROUP	Units	Present Rates	Proposed Rates	Rate Change	%Change	
		A	B	C	D	E	
1	INTERSTATE TRANSPORTATION						1
2			*Last*				2
3	Schedule GPIN		*Adopted*				3
4	Volumetric Charges, 1-year purchase	C/therm	1.953	1.282	-0.671	-34.4%	4
5	Volumetric Charges, monthly purchase	C/therm	1.953	1.282	-0.671	-34.4%	5
6							6
7	AVERAGE TARIFF RATE	C/therm	1.953	1.282	-0.671	-34.4%	7
8							8
9							9
10	GAS PROCUREMENT SERVICES						10
11							11
12	Schedule GPNC, 1-year purchase commitment		*Rates Not Applicable for this filing*				12
13	Schedule GPNC-S, monthly purchase commitment		*Rates Not Applicable for this filing*				13
14							14
15							15
16							16
17	GAS STORAGE SERVICES						17
18							18
19	Schedule G-USTOR						19
20	Reservation Charge, per therm of Inventor	C/therm	2.277	0.000	-2.277	-100.0%	20
21	Volumetric Rate, per therm of throughput	C/therm	0.160	0.000	-0.160	-100.0%	21
22	Average Tariff Rate, per therm of Inventory	C/therm	6.247	0.001			22
23							23
24	Schedule G-CSTOR		*(Reflects Charges on SoCalGas Schedule G-LTS)*				24
25	Reservation Charges for:						25
26	Inventory capacity reserved for the year	C/dtherm	39.000	18.800	-20.200	-51.8%	26
27	Injection capacity reserved for the month	C/dthm/day	16.677	22.083	5.406	32.4%	27
28	Withdrawal capacity reserved for the yea	$/dthm/day	$9.161	$13.400	$4.239	46.3%	28
29							29
30	Injection Charges: In-Kind	%reduction	2.440%	2.440%			30
31	O&M	C/therm	0.439	0.307	-0.132	-30.1%	31
32							32
33	Withdrawal Charges	C/therm	0.189	0.238	0.049	26.0%	33

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SUMMARY OF REAL-TIME PRICING RATES

	CUSTOMER GROUP			Units	Present Rates	Proposed Rates	Rate Change	%Change	
				A	B	C	D	E	
1	Schedule XGSR		*Bundled Residential Services (Stand Alone Tariff)*						1
2									2
3	Special Metering Fee			$/month	$3.28	$3.28	0.000	0.0%	3
4	On-Peak Energy Charge			C/therm	130.554	111.852	-18.702	-14.3%	4
5	Off-Peak Energy Charge			C/therm	49.367	47.817	-1.550	-3.1%	5
6									6
7									7
8									8
9	Schedule XGTS		*SDG&E Transportation-Only Service to be taken in conjunction with GITS*						9
10									10
11	Special Metering Fee			$/month	$207	$207	0.000	0.0%	11
12	Contact Closure Service Fee			$/month	$110	$110	0.000	0.0%	12
13									13
14	Customer Charges								14
15									15
16	0	to 5	therms per hour	$/month	$15	$10	($5)	-33.3%	16
17	6	to 10	therms per hour	$/month	$25	$15	($10)	-40.0%	17
18	11	to 25	therms per hour	$/month	$50	$35	($15)	-30.0%	18
19	26	to 50	therms per hour	$/month	$100	$65	($35)	-35.0%	19
20	51	to 150	therms per hour	$/month	$200	$130	($70)	-35.0%	20
21	151	to 250	therms per hour	$/month	$400	$260	($140)	-35.0%	21
22	251	to 500	therms per hour	$/month	$800	$540	($260)	-32.5%	22
23	501	to 1,000	therms per hour	$/month	$1,600	$1,100	($500)	-31.3%	23
24	1,001	to 3,000	therms per hour	$/month	$2,500	$1,700	($800)	-32.0%	24
25	3,001	to 6,000	therms per hour	$/month	$5,000	$3,400	($1,600)	-32.0%	25
26	6,001	to 20,000	therms per hour	$/month	$10,000	$6,500	($3,500)	-35.0%	26
27	20,001	to 40,000	therms per hour	$/month	$20,000	$13,000	($7,000)	-35.0%	27
28	Over	40,000	therms per hour	$/month	$40,000	$27,000	($13,000)	-32.5%	28
29									29
30	Contract Minimum Demand Charge			$/month	$30.059	$46.909	16.850	56.1%	30
31									31
32	On-Peak Energy Charge			C/therm	282.249	440.458	158.209	56.1%	32
33	Off-Peak Energy Charge			C/therm	0.464	0.643	0.179	38.7%	33

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SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS

Knight - Alternate Decision

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	UNBUNDLED STORAGE	ZONE RATE CREDIT	SYSTEM TOTAL
1	MARGINAL CUSTOMER COST REVENUE	694,783	15,514	2,032	1,654	N/A	0	713,983
2	MARGINAL MEDIUM PRESSURE DISTRIBUTION COST REVENUE	289,881	18,597	0	0	N/A	0	308,478
3	MARGINAL HIGH PRESSURE DISTRIBUTION COST REVENUE	30,549	7,563	163	0	N/A	0	38,275
4	MARGINAL TRANSMISSION COST REV.	36,206	37,410	5,342	12,235	N/A	(5,665)	85,528
5	STORAGE LOAD BALANCING COST	688	10,425	2,080	1,245	N/A	0	14,439
6	SEASONAL STORAGE COSTS	49,525	0	0	7,786	17,532	0	74,844
7	COMPANY USE TRANSMISSION	4,356	4,906	707	1,493	N/A	(2,929)	8,534
8	SYSTEM MARGINAL COST REVENUE	1,105,989	94,415	10,324	24,414	17,532	(8,594)	1,244,081
9	SCALING MARKUP:	180,290	15,391	20,318	3,980	2,858	(1,401)	221,436
10	MARKETING COSTS	79,578	4,711	350	248	89	0	84,976
11	ARCO PIPELINE LEASE	0	0	0	0	N/A	0	0
11a	SDG&E MORENO CREDIT	528	45	N/A	(573)	N/A	N/A	0
12	ZONE RATE CREDIT ELEGIBILITY CREDIT	(1,805)	(154)	N/A	(40)	N/A	1,999	(0)
13	SCALED SYSTEM MARGINAL COST REV.	1,364,579	114,408	30,992	28,030	20,479	(7,996)	1,560,492
14	UNCOLLECTIBLES	6,468	542	0	0	97	(38)	7,069
15	TOTAL ALLOCATED MARGIN	1,371,047	114,950	30,992	28,030	20,576	(8,034)	1,567,561

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SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	UNBUNDLED STORAGE	ZONE RATE CREDIT	SYSTEM TOTAL
	OTHER OPERATING COSTS AND REVENUES							
1	Exchange Revenues & Interutility Transactions	(371)	(383)	0	(125)	N/A	N/A	(879)
2	Core Brokerage Fee Adjustment	(6,717)	0	N/A	N/A	N/A	N/A	(6,717)
3	Noncore Brokerage Fee Adjustment	N/A	(577)	N/A	(178)	N/A	N/A	(754)
3a	HUB Revenues	0	0	0	0	N/A	N/A	0
4	Fuel Cell Equipment Fee Revenues	(375)	(32)	0	(8)	N/A	N/A	(415)
5	Company Use Gas: Storage	2,971	195	28	407	N/A	N/A	3,601
6	Other Company Use Gas	343	387	56	118	N/A	N/A	904
7	Unaccounted For Gas	16,468	4,224	1,540	1,445	N/A	N/A	23,677
8	Carrying Cost Storage Inv.: Load Balancing	0	72	0	25	N/A	N/A	97
9	Well Incidents and Surface Leaks	267	10	0	3	0	N/A	279
10	Pitas Point PPSA and F & U	(94)	(106)	0	(32)	0	N/A	(232)
	TRANSITION COSTS							
11	MPO Transition Cost Adjustment	21	24	0	7	N/A	N/A	52
12	Pitco/Popco Transition Cost	42,721	48,109	0	14,644	N/A	N/A	105,474
13	Interstate Trans. Cost Surcharge Acount (ITCS)	12,153	52,502	0	15,982	N/A	N/A	80,636
	BALANCING AND TRACKING ACCOUNTS							
14	NGV Account (NGVA)	5,939	6,688	0	251	N/A	N/A	12,878
	Noncore Storage Balancing Account (NSBA)							
15	Subscribed Storage Revenue Subaccount	N/A	(497)	0	(151)	N/A	N/A	(648)
16	Storage Transition and Bypass Subaccount	5,835	6,571	0	2,000	N/A	N/A	14,406
17	Zone Rate Credit Limitation Memorandum Account (ZRCLM	(133)	(11)	0	(3)	N/A	N/A	(147)
18	N/C Brokerage Fee Balancing Account (BFBA)	N/A	145	0	44	N/A	N/A	189
19	Interim Zone Rate Credit Account (IZRCA)	25	25	0	6	N/A	N/A	56
20	Hazardous Substances Cost Recovery Account (HSCRA)	2,569	2,893	0	881	N/A	N/A	6,343
21	Conservation Expense Account (CEA)	(57,998)	(166)	0	0	N/A	N/A	(58,164)
22	RD&D Expense Account (RDDEA)	(13,001)	(1,110)	0	(296)	N/A	N/A	(14,396)
23	Core Fixed Cost Account (CFCA)	157,480	0	N/A	N/A	N/A	N/A	157,480
24	1993 BCAP Phase IV Settlement (CFCA)	N/A	4,186	N/A	N/A	N/A	N/A	4,186
25	Enhanced Oil Recovery Account (EORA)	10,022	812	N/A	209	N/A	N/A	11,043
26	Minimum Purchase Obligation (MPO)	N/A	(2,649)	N/A	(806)	N/A	N/A	(3,456)
27	Pipeline Demand Charges (PDC)	N/A	0	N/A	0	N/A	N/A	0
28	Carrying Cost of Storage (CCS)	N/A	13	N/A	0	N/A	N/A	13
29	Take-or-Pay (TOP)	N/A	(864)	N/A	(263)	N/A	N/A	(1,128)
30	Non-Core Fixed Cost Account (NFCA)	N/A	444	N/A	135	N/A	N/A	580
31	Non-Core Cost/Revenue Memo Acct(NCRMA)	0	0	0	0	N/A	N/A	0
32	Auditing Expense Account (AEA)	0	0	0	0	N/A	N/A	0
33	Intervenor Compensation (IN)	0	0	0	0	N/A	N/A	0
34	Research Royalty Memorandum Account (RRMA)	(548)	(47)	0	(12)	N/A	N/A	(607)
35	Environmental Fee Account (EFA)	(5,781)	(494)	0	(127)	N/A	N/A	(6,401)
36	Fuel Cell Proceeds Memorandum Account (FCPMA)	(454)	(39)	0	(10)	N/A	N/A	(503)

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SOUTHERN CALIFORNIA GAS COMPANY

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS

LINE #	DESCRIPTION	CORE	RETAIL NONCORE	EOR	NONCORE WHOLESALE	UNBUNDLED STORAGE	ZONE RATE CREDIT	SYSTEM TOTAL
37	Pipeline Demand Charges: EP & TW Traditional - Core	150,447	N/A	N/A	N/A	N/A	N/A	150,447
38	TOTAL TRANSPORTATION REVENUE REQUIREMENT	1,692,837	235,277	32,616	62,188	20,576	(8,034)	2,035,460
39	TOTAL TARIFFED REVENUE REQUIREMENTS	1,692,837	235,277	N/A	62,188	20,576	(8,034)	2,002,846
40	Average Year Throughput (Mdth)	358,595	403,815	N/A	123,493	N/A	N/A *	885,903
41	TARIFFED TRANSPORTATION RATE (¢/th)	47.208	5.826	N/A	5.036	N/A	(0.417)	22.608
	GAS PRUCHASES AND RELATED COSTS							
42	Cost of Gas	588,744						
43	Core Brokerage Fee Adjustment	6,717						
44	CPGA	0						
45	Carrying Cost of Storage Inv.: Other (CCSI)	2,018						
46	Total Gas Costs	597,479						
47	Sales Volumes (Mdth)	334,160						
48	Total Gas Costs (¢/th)	17.879						
49	Pipeline Demand Charges; San Juan Lateral only	7,402						
50	Pipeline Demand Charges (¢/th)	0.221						
51	Total Sales Related Procurement Costs	604,881						
52	Total Sales Related Procurement Rate (¢/th)	18.100						
53	Total Sales Rate (¢/th)	65.832						
	CPGA - Direct Refund	(80,291)						
	Total Sales Related Procurement Costs w/CPGA Refund	524,590						
	* Throughput for Zone Rate Credit (Mdth)	192,882						

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SOUTHERN CALIFORNIA GAS COMPANY

CORE REVENUE ALLOCATION
Knight - Alternate Decision

LINE #	MARGINAL COST COMPONENTS	LRMC COST ALLOCATION (M$);MARGINAL COST REVENUE					
		CORE					
		RESIDEN-TIAL	COM/IND				Total Core
			G10	G20	NonRes A/C	Gas Engine	
		(b)	(c)	(d)			(f)
	CUSTOMER RELATED						
(1)	NUMBER OF CUSTOMERS	4,406,830	215,909	33	67	1,067	4,623,915
(2)	MARGINAL CUSTOMER COST	0.13630	0.41254	3.09256	6.16203	4.27944	
(3)	MARGINAL CUSTOMER COST REVENUE	600,631	89,070	102	413	4,566	694,783
	COMMON DISTRIBUTION - MEDIUM PRESSURE						
(4)	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	2,415	551	25	1	1	2,993
(5)	MARGINAL DISTRIBUTION COST	96.8594	96.8594	96.8594	96.8594	96.8594	
(6)	MARGINAL DISTRIBUTION COST REVENUE	233,915	53,370	2,421	97	77	289,881
	COMMON DISTRIBUTION - HIGH PRESSURE						
(7)	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	45,683	10,486	598	31	38	56,835
(8)	MARGINAL DISTRIBUTION COST	0.5375	0.5375	0.5375	0.5375	0.5375	
(9)	MARGINAL DISTRIBUTION COST REVENUE	24,555	5,636	321	17	20	30,549
(10)	TOTAL COMMON DISTRIBUTION COST REVENUE	258,470	59,005	2,743	114	98	320,430
	TRANSMISSION						
(11)	COLD YEAR THROUGHPUT (MDTH)	296,862	89,764	5,379	390	2,454	394,838
(12)	MARGINAL TRANSMISSION COST	0.0917	0.0917	0.0917	0.0917	0.0917	
(13)	TOTAL TRANSMISSION COST REVENUE	27,216	8,235	493	36	225	36,206

SOUTHERN CALIFORNIA GAS COMPANY

CORE REVENUE ALLOCATION

Knight - Alternate Decision

MARGINAL COST COMPONENTS — **LRMC COST ALLOCATION (M$):MARGINAL COST REVENUE**

LINE #		CORE					
		RESIDEN-TIAL	COM/IND				Total Core
			G10	G20	NonRes A/C	Gas Engine	
	STORAGE						
	INVENTORY:						
(14)	INVENTORY RESERVATION (MMCF)	59,324	10,003	672	0	0	70,000
(15)	MARGINAL INVENTORY COST	0.1832	0.1832	0.1832	0.1832	0.1832	
(16)	MARGINAL INVENTORY COST REVENUE	10,870	1,833	123	0	0	12,820
	INJECTION CAPACITY:						
(17)	INJECTION RESERVATION (MMCFD)	277	47	3	0	0	327
(18)	MARGINAL INJECTION COST	21.499	21.499	21.499	21.499	21.499	
(19)	MARGINAL INJECTION CAPACITY COST REVENUE	5,960	1,005	66	0	0	7,032
	VARIABLE INJECTION COST:						
(20)	INJECTIONS (MDTH)	61,410	10,355	696	7	331	72,800
(21)	VARIABLE O&M COST	0.029	0.029	0.029	0.014	0.014	
(22)	TOTAL VARIABLE INJECTION COST REVENUE	1,775	299	20	0	5	2,099
	WITHDRAWAL CAPACITY:						
(23)	WITHDRAWAL RESERVATION (MMCFD)	1,602	365	17	1	1	1,985
(24)	MARGINAL WITHDRAWAL COST	13.067	13.067	13.067	13.067	13.067	
(25)	MARGINAL WITHDRAWAL CAP. COST REVENUE	20,930	4,775	217	9	7	25,938
	VARIABLE WITHDRAWAL COST:						
(26)	WITHDRAWALS (MDTH)	61,410	10,355	696	7	331	72,800
(27)	VARIABLE O&M COST	0.022	0.022	0.022	0.011	0.011	
(28)	TOTAL VARIABLE WITHDRAWAL COST REVENUE	1,378	232	16	0	4	1,630
(29)	SUBTOTAL - SEASONAL STORAGE	40,913	8,145	443	9	15	49,525
	LOAD BALANCING COST						
(30)	MARGINAL LOAD BALANCING COST REVENUE	512	161	10	1	5	688
(31)	COMPANY USE GAS: TRANSMISSION	3,240	1,019	62	5	30	4,366
(32)	SYSTEM MARGINAL COST REVENUE	930,983	165,636	3,864	677	4,939	1,105,969
	SCALED LRMC REVENUE	1,082,746	192,637	4,482	670	5,744	1,286,278
(33)	MARKETING (including DSM)	53,870	25,193	407	3	105	79,578
(34)	ARCO Cuyama/Casitas Pipeline Lease (C)	0	0	0	0	0	0
	SDG&E Moreno Credit EPMC)	444	79	2	0	2	528
(35)	Zone Rate Credit Elegibility Adjustment EPMC)	(1,519)	(270)	(6)	(1)	(8)	(1,805)
(36)	MARGINAL COST REVENUE W/MKTG & ARCO	1,132,731	223,773	4,886	388	2,802	1,364,579
(37)	UNCOLLECTIBLES	5,382	1,032	23	3	28	6,468
(38)	TOTAL ALLOCATED MARGIN	1,140,921	216,671	4,906	676	5,871	1,371,047
(39)	AVERAGE YEAR THROUGHPUT, MDth	266,706	83,903	5,141	390	2,454	358,595

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SOUTHERN CALIFORNIA GAS COMPANY

CORE REVENUE ALLOCATION

	OTHER COST COMPONENTS	OTHER COSTS: ALLOCATION (M$)					
		Residential	G-10	G-20	NonRes A/C	Gas Engine	Total Core
Line	Forecast Period Costs	Cost	Cost	Cost	Cost	Cost	Cost
	TRANSPORTATION REVENUE REQ.						
(40)	Subtotal - Margin - Base	1,140,921	218,671	4,908	676	5,871	1,371,047
	Other Operating Costs and Revenues						
(41)	Exchange Revenues & Interutility Transactions	(279)	(84)	(5)	(0)	(2)	(371)
(42)	Core Brokerage Fee Adjustment	(4,996)	(1,572)	(96)	(7)	(46)	(6,717)
(43)	Noncore Brokerage Fee Adjustment	N/A	N/A	N/A	N/A	N/A	N/A
(43a)	HUB Revenues Pre 1997	-	-	-	-	-	-
(44)	Fuel Cell Equipment Revenues	(315)	(56)	(1)	(0)	(2)	(375)
(45)	Company Use Gas: Storage	2,489	438	29	0	14	2,971
(46)	Other Company Use Gas	255	80	5	0	2	343
(47)	Unaccounted For Gas	15,842	675	(65)	2	14	16,468
(48)	Carrying Cost Storage Inv.: Load Balancing	-	-	-	-	-	-
(49)	Well Incidents & Surface Leaks	226	38	3	-	-	267
(50)	Pitas Point PPSA & F&U	(70)	(22)	(1)	(0)	(1)	(94)
(51)	Subtotal Other Operating Costs and Revenues	13,152	(502)	(133)	(5)	(20)	12,492
	Transition Costs						
(52)	MPO Transition Cost Adjustment	16	5	0	0	0	21
(53)	Pitco/Popco Transition Costs	31,774	9,996	612	46	292	42,721
(54)	Interstate Trans. Cost Surcharge Acount (ITCS)	9,039	2,844	174	13	83	12,153
(55)	Subtotal Transition Costs	40,828	12,844	787	60	376	54,895

* Average Year Throughput, Core 10% of PL Demand Cap

SOUTHERN CALIFORNIA GAS COMPANY

CORE REVENUE ALLOCATION

	OTHER COST COMPONENTS	OTHER COSTS: ALLOCATION (M$) Residential	G-10	G-20	NonRes A/C	Gas Engine	Total
Line	Forecast Period Costs	Cost	Cost	Cost	Cost	Cost	Core Cost
	Balancing and Tracking Accounts:						
(56)	NGV Account (NGVA)	4,417	1,390	85	6	41	5,939
	Noncore Storage Balancing Account (NSBA)						
(57)	Subscribed Storage Revenue Account	N/A	N/A	N/A	N/A	N/A	N/A
(58)	Storage Transition and Bypass Subaccount	4,340	1,365	84	6	40	5,835
(59)	Zone Rate Credit Limitation Memo Acct(ZRCLMA)	(112)	(20)	(0)	(0)	(1)	(133)
(60)	N/C Brokerage Fee Balancing Account (BFBA)	N/A	N/A	N/A	N/A	N/A	N/A
(61)	Interim Zone Rate Credit Account (IZRCA)	18	6	0	0	0	25
(62)	Hazardous Substan. Cost Recov. Acct (HSCRA)	1,911	601	37	3	18	2,569
(63)	Conservation Expense Account (CEA)	(38,402)	(18,531)	(1,003)	-	(63)	(57,996)
(64)	R D & D Expense Account (RDDEA)	(10,944)	(1,947)	(46)	(7)	(56)	(13,001)
(65)	Core Fixed Cost Account (CFCA)	117,282	36,896	2,261	(37)	1,079	157,480
(66)	1993 BCAP Phase IV Settlement (CFCA)	N/A	N/A	N/A	N/A	N/A	N/A
(67)	Enhanced Oil Recovery Account-Core(EORA)	8,436	1,501	35	5	45	10,022
(68)	Enhanced Oil Recovery Account-N/C (EORA)	N/A	N/A	N/A	N/A	N/A	N/A
(69)	Minimum Purchase Obligation (MPO)	N/A	N/A	N/A	N/A	N/A	N/A
(70)	Pipeline Demand Charges (PDC)	N/A	N/A	N/A	N/A	N/A	N/A.
(71)	Carrying Cost of Storage (CCS)	N/A	N/A	N/A	N/A	N/A	N/A
(72)	Take-or-Pay (TOP)	N/A	N/A	N/A	N/A	N/A	N/A
(73)	Non-Core Fixed Cost Account (NFCA)	N/A	N/A	N/A	N/A	N/A	N/A
(74)	Non-Core Cost/Revenue Memo Acct(NCRMA)	-	-	-	-	-	-
(75a)	Auditing Expense Account (AEA)	-	-	-	-	-	-
(75b)	Intervenor Compensation (IN)	-	-	-	-	-	-
(75c)	Research Royalty Memorandum Account (RRMA)	(461)	(82)	(2)	(0)	(2)	(548)
(75d)	Environmental Fee Account (EFA)	(4,866)	(866)	(20)	(3)	(26)	(5,781)
(75e)	Fuel Cell Proceeds Memorandum Acct (FCPMA)	(382)	(68)	(2)	(0)	(2)	(454)
(75)	Subtotal Balancing and Tracking Accounts	81,238	20,245	1,429	(27)	1,071	103,956
(76)	Subtotal-Transportation Revenue Requirement	1,276,139	251,257	6,992	704	7,297	1,542,389
(77)	Subtotal- Transportation Revenue Requirement (¢/th)	47,848	29,948	13,599	18,045	29,737	43,012

APPENDIX D

SOUTHERN CALIFORNIA GAS COMPANY

CORE REVENUE ALLOCATION

Line	OTHER COST COMPONENTS Forecast Period Costs	OTHER COSTS: ALLOCATION (M$) (Cont) Residential Cost	G-10 Cost	G-20 Cost	NonRes A/C Cost	Gas Engine Cost	Total Core Cost
(78)	Subtotal-Transportation Revenue Requirement	1,276,139	251,257	6,992	704	7,297	1,542,389
(79)	Pipeline Demand Charges-EP&TW Trad-Core	111,896	35,201	2,157	164	1,030	150,447
(80)	UEG/Cogeneration Parity Adjustment	0	0	0	0	0	0
(81)	SDG&E LTK Reconciliation Account	0	0	0	0	0	0
	Transportation Revenue Req w/o N/C Rate Cap	1,388,035	286,459	9,149	867	8,327	1,692,837
(82)	TOTAL TRANS. REV. REQ. w/Cap	1,388,035	286,459	9,149	867	8,327	1,692,837
	Tariffed Rates						
(83)	Total Transportation Costs (Line 46) Less: EOR	1,388,035	286,459	9,149	867	8,327	1,692,837
(84)	Core Averaging	(32,246)	32,246	-	-	-	-
(85)	TOTAL TRANS. REV. REQ. w/o EOR	1,355,790	318,704	9,149	867	8,327	1,692,837
(86)	Average Year Throughput (MDth)	266,706	83,903	5,141	390	2,454	358,595
(87)	TARIFFED TRANSPORTATION RATES (¢/th)	50.835 *	37.985 *	17.796	22.241	33.932	47.206
	* Reflects Partial Core Deaveraging.						
(88)	ITCS Rate (¢/th)						
	Gas Purchases & Related Costs						
(89)	WACOG	460,776	116,306	7,895	687	3,080	588,744
(90)	Core Brokerage Fee Adjustment	5,257	1,327	90	8	35	6,717
(91)	CPGA	-	-	-	-	-	-
(92)	Carrying Cost Storage Inv: Other (CCSI)	1,579	399	27	2	11	2,018
(93)	Subtotal-Purchased Gas Costs	467,612	118,032	8,012	697	3,126	597,479
(94)	Gas Purchases Cents Per Therm Basis	17.879	17.879	17.879	17.879	17.879	17.879
(95)	Core Pipeline Demand Charges (SJ Lateral)	5,793	1,462	99	9	39	7,402
(96)	Core Pipeline Demand Charges (¢/th)	0.221	0.221	0.221	0.221	0.221	0.221
(97)	TARIFFED SALES RATES (¢/th)						
(98)	Average Year Sales (MDth)	261,544	66,017	4,481	390	1,748	334,180
(99)	CORE SALES REVENUES (M$)	1,802,962	370,258	16,085	1,573	9,095	2,199,964
(99a)	CPGA - Direct Refund	(62,839)	(15,861)	(1,077)	(94)	(420)	(80,291)
(99b)	Total Core Sales Revenues w/CPGA Refund (M$)	1,740,113	354,397	15,008	1,480	8,676	2,119,674
(100)	Core Pipeline Demand Reserved for Transport (M$)	190					

APPENDIX D

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SOUTHERN CALIFORNIA GAS COMPANY

NONCORE REVENUE ALLOCATION

Knight - Alternate Decision

LINE #	MARGINAL COST COMPONENTS	LRMC COST ALLOCATION (M$);MARGINAL COST REVENUE: NONCORE RETAIL					NONCORE WHOLESALE				NBUNDLED NONCORE STORAGE	NONCORE TOTAL	Zone Rate Credit
		COM/IND G30	COGEN G50	UEG G60	EOR G40	otal Noncore Retail	Long Beach	SDG&E	Southwest Gas	otal Noncore Wholesale			
	CUSTOMER RELATED	(g)	(j)	(k)	(m)		(n)	(o)			(p)	(q)	
(1)	NUMBER OF CUSTOMERS	1,096	239	8	72	1,415	1	1	1	3	N/A	1,416	
(2)	MARGINAL CUSTOMER COST	8.14700	7.40656	601.8099	28.22059		400.9506	1,159.585	93.6343		N/A	0.00000	
(3)	MARGINAL CUSTOMER COST REVENUE	8,929	1,771	4,814	2,032	17,546	401	1,160	94	1,654	0	19,200	
	COMMON DISTRIBUTION - MEDIUM PRESSURE												
(4)	MEDIUM PRESSURE PEAK DAY DEMAND (MMCFD)	183	9	0	0	192	0	0	0	0	N/A	192	
(5)	MARGINAL DISTRIBUTION COST	96.8504	96.8504	96.8504	96.8504		96.8504	96.8504	96.8504		N/A	0.0000	
(6)	MARGINAL DISTRIBUTION COST REVENUE	17,725	872	0	0	18,597	0	0	0	0	N/A	18,597	
	COMMON DISTRIBUTION - HIGH PRESSURE												
(7)	HIGH PRESSURE PEAK MONTH DEMAND (MMCF)	10,262	2,677	1,132	303	14,374	0	0	0	0	N/A	14,374	
(8)	MARGINAL DISTRIBUTION COST	0.5375	0.5375	0.5375	0.5375		0.5375	0.5375	0.5375		N/A	0.0000	
(9)	MARGINAL DISTRIBUTION COST REVENUE	5,516	1,439	608	163	7,726	0	0	0	0	N/A	7,726	
(10)	TOTAL COMMON DISTRIBUTION COST REVENUE	23,241	2,311	608	163	26,323	0	0	0	0	N/A	26,323	
	TRANSMISSION												
(11)	COLD YEAR THROUGHPUT (MDTH)	124,136	82,483	201,139	58,228	465,986	6,692	117,340	9,328	133,360	N/A	599,346	241,103
(12)	MARGINAL TRANSMISSION COST	0.0917	0.0917	0.0917	0.0917		0.0917	0.0917	0.0917		N/A	0.0000	(0.0235)
(13)	TOTAL TRANSMISSION COST REVENUE	11,389	7,567	18,454	5,342	42,752	614	10,766	856	12,236	N/A	54,987	(5,665)

SOUTHERN CALIFORNIA GAS COMPANY

NONCORE REVENUE ALLOCATION

Knight - Alternate Decision

LINE #	MARGINAL COST COMPONENTS	LRMC COST ALLOCATION (M$):MARGINAL COST REVENUE — NONCORE RETAIL: COM/IND G30	COGEN G50	UEG G60	EOR G40	otal Noncore Retail	NONCORE WHOLESALE: Long Beach	SDG&E	Southwest Gas	otal Noncore Wholesale	NBUNDLED NONCORE STORAGE	NONCORE TOTAL	Zone Rate Credit
	STORAGE												
	INVENTORY:												
(14)	INVENTORY RESERVATION (MMCF)	N/A	N/A	N/A	N/A	N/A	750	8,000	1,500	10,250	29,750	40,000	
(15)	MARGINAL INVENTORY COST	N/A	N/A	N/A	N/A	N/A	0.1832	0.1832	0.1832		0.1832	0.0000	
(16)	MARGINAL INVENTORY COST REVENUE	N/A	N/A	N/A	N/A	N/A	137	1,466	275	1,878	5,451	7,329	
	INJECTION CAPACITY:												
(17)	INJECTION RESERVATION (MMCFD)	N/A	N/A	N/A	N/A	N/A	4	30	7	41	0	41	
(18)	MARGINAL INJECTION COST	N/A	N/A	N/A	N/A	N/A	21.499	21.499	21.499		21.499	0.000	
(19)	MARGINAL INJECTION CAPACITY COST REVENUE	N/A	N/A	N/A	N/A	N/A	75	653	151	879	0	879	
	VARIABLE INJECTION COST:												
(20)	INJECTIONS (MDTH)	N/A	N/A	N/A	N/A	N/A	780	8,320	1,560	10,660	30,940	41,600	
(21)	VARIABLE O&M COST	N/A	N/A	N/A	N/A	N/A	0.029	0.029	0.029		0.029	0.000	
(22)	TOTAL VARIABLE INJECTION COST REVENUE	N/A	N/A	N/A	N/A	N/A	23	240	45	308	894	1,202	
	WITHDRAWAL CAPACITY:												
(23)	WITHDRAWAL RESERVATION (MMCFD)	N/A	N/A	N/A	N/A	N/A	50	233	60	343	803	1,146	
(24)	MARGINAL WITHDRAWAL COST	N/A	N/A	N/A	N/A	N/A	13.067	13.067	13.067		13.067	0.000	
(25)	MARGINAL WITHDRAWAL CAP. COST REVENUE	N/A	N/A	N/A	N/A	N/A	653	3,045	784	4,482	10,493	14,975	
	VARIABLE WITHDRAWAL COST:												
(26)	WITHDRAWALS (MDTH)	N/A	N/A	N/A	N/A	N/A	780	8,320	1,560	10,660	30,940	41,600	
(27)	VARIABLE O&M COST	N/A	N/A	N/A	N/A	N/A	0.022	0.022	0.022		0.022	0.000	
(28)	TOTAL VARIABLE WITHDRAWAL COST REVENUE	N/A	N/A	N/A	N/A	N/A	17	187	35	239	694	933	
(29)	SUBTOTAL - SEASONAL STORAGE	0	0	0	0	0	906	5,591	1,290	7,786	17,532	25,319	
	LOAD BALANCING COST												
(30)	MARGINAL LOAD BALANCING COST REVENUE	2,410	1,624	6,391	2,080	12,505	213	848	184	1,245	N/A	13,751	
(31)	COMPANY USE GAS: TRANSMISSION	1,487	1,002	2,417	707	5,613	79	1,310	105	1,493	N/A	7,107	(2,929)
(32)	SYSTEM MARGINAL COST REVENUE	47,456	14,276	32,684	10,324	104,740	2,213	19,673	2,528	24,414	17,532	146,686	(8,694)
	SCALED LRMC REVENUE	55,192	16,602	38,012	30,642	140,448	2,573	22,880	2,940	28,394	20,390	189,233	(9,995)
(33)	MARKETING (Including DSM)	3,275	739	697	350	5,061	80	89	79	248	89	5,398	0
(34)	ARCO Cuyama/Castias Pipeline Lease (C)	0	0	0	0	0	0	0	0	0	N/A	0	0
	SDG&E Moreno Credit EPMC)	23	7	16	N/A	46	1	(576)	1	(573)	N/A	(528)	N/A
(35)	Zone Rate Credit Elegibility Adjustment EPMC)	(77)	(23)	(53)	-	(154)	(4)	(32)	(4)	(40)	N/A	(194)	1,999
(36)	MARGINAL COST REVENUE W/MKTG & ARCO	58,412	17,326	38,671	30,992	145,400	2,651	22,362	3,017	28,030	20,479	193,909	(7,996)
(37)	UNCOLLECTIBLES	277	82	183	-	542	-	-	-	-	97	639	(38)
(38)	TOTAL ALLOCATED MARGIN	58,689	17,407	38,854	30,992	145,942	2,651	22,362	3,017	28,030	20,576	194,548	(8,034)
(39)	AVERAGE YEAR THROUGHPUT, MDth	122,393	82,483	198,939	58,228	462,043	6,510	108,291	8,692	123,493	N/A	585,535	241,103

Appendix E

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SAN DIEGO GAS & ELECTRIC

1996 Biennial Cost Allocation Proceeding

GAS LONG-RUN MARGINAL COST SUMMARY

Effective January 1, 1997

		CORE					NONCORE				SYSTEM
		Resid	GN-1	NGV	GN-2	Core	GTNC	Cogen	UEG	Noncore	TOTALS
		A	B	C	D	E	F	I	J	K	L
			Small Comml	Small Comml Vehicles	Large Comml		[illegible]				
1	**CUSTOMER COSTS:**										
2	$/Customer-Year	$99.59	$127.91	$542	$4,931	$102	$6,522	$8,208	$46,266	$9,306	$104
3	No. Customers	697,464	27,201	1,795	18	726,498	97	57	9	163	726,601
4											
5	**CUSTOMER $1000**	$69,464	$3,479	$973	$89	$74,005	$633	$468	$416	$1,517	$75,522
6											
7	**DISTRIBUTION COSTS:**										
8	HPS $/Mcfd	$39.98	$39.98	$39.98	$39.98	$39.98	$39.98	$39.98	$39.98	$39.98	$39.98
9	Normal Peak Day	278,500	56,100	1,100	3,800	339,500	23,000	20,900	100	44,000	383,500
10											
11	High Pressure $1000	$11,134	$2,243	$44	$152	$13,573	$920	$836	$4	$1,759	$15,332
12											
13	MPS $/Mcfd	$98.78	$98.78	$98.78	$98.78	$98.78	$98.78	$98.78	$98.78	$98.78	$98.78
14	Normal Peak Day	278,500	56,100	1,100	3,300	339,000	10,600	1,900	0	12,500	351,500
15											
16	Medium Pressure $1000	$27,510	$5,542	$109	$326	$33,486	$1,047	$188	$0	$1,235	$34,721
17											
18	**DISTRIBUTION $1000**	$38,645	$7,784	$153	$478	$47,060	$1,967	$1,023	$4	$2,994	$50,054
19											
20	**TRANSMISSION COSTS:**										
21	$/Mcf	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89	$1.89
22	Cold-Yr CPM (mmcf)	5,398	1,419	28	115	6,959	855	1,129	2,916	4,900	11,859
23											
24	Non-Fuel $000	$10,202	$2,681	$53	$217	$13,153	$1,616	$2,134	$5,511	$9,261	$22,414
25											
26	$/mtherm	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08	$1.08
27	Adj.Avg-Year, mtherms	340,731	115,810	3,250	12,695	472,486	102,228	135,067	419,210	656,505	1,128,991
28											
29	Fuel $000	$369	$125	$4	$14	$511	$111	$146	$454	$710	$1,222
30											
31	**TRANSMISSION $1000**	$10,570	$2,806	$57	$231	$13,664	$1,726	$2,280	$5,965	$9,971	$23,636
32											
33	**RECAP:**										
34	**CUSTOMER $1000**	$69,464	$3,479	$973	$89	$74,005	$633	$468	$416	$1,517	$75,522
35	**DISTRIBUTION $1000**	$38,645	$7,784	$153	$478	$47,060	$1,967	$1,023	$4	$2,994	$50,054
36	**TRANSMISSION $1000**	$10,570	$2,806	$57	$231	$13,664	$1,726	$2,280	$5,965	$9,971	$23,636
37											
38	**LRMC TOTALS $1000**	$118,679	$14,070	$1,182	$798	$134,729	$4,325	$3,771	$6,385	$14,482	$149,211
39	*DRA PROPOSAL*										
40	*Total EPMC Factors*	*79.5%*	*9.4%*	*0.8%*	*0.6%*	*90.3%*	*2.9%*	*2.5%*	*4.3%*	*9.7%*	*100.0%*

Appendix E
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SAN DIEGO GAS & ELECTRIC
1996 Biennial Cost Allocation Proceeding

GAS COST ALLOCATION SUMMARY
By Type of Cost
Effective January 1, 1997

	CORE					NONCORE				SYSTEM
	Resid	GN-1	NGV	GN-2	Core	GTNC	Cogen	UEG	Noncore	TOTALS
	A	B	C	D	E	F	I	J	K	L
		Small Comml	*Small Comml*	*Large Comml*		*[illegible]*				
1 Gas Margin Recovery										$197,825
2 Less Miscellaneous Revenues										$2,804
3 Less Brokerage Fees										$903
4										
5 Margin Recovered in Rates	$154,397	$18,305	$1,538	$1,036	$175,276	$5,627	$4,906	$8,307	$18,840	$194,118
6 *EPMC Allocators*	*79.5%*	*9.4%*	*0.8%*	*0.5%*	*90.3%*	*2.9%*	*2.5%*	*4.3%*	*9.7%*	*100.0%*
7										
8 + SDG&E Acct Balances	$5,068	$1,722	$48	$189	$7,027	$798	$944	$3,666	$5,409	$12,437
9 + Net SDGE CARE Costs	$1,015	($893)	($25)	($82)	$15	($788)	$0	($0)	($788)	($773)
10 + Other SDG&E Costs	$1,125	$322	$8	$33	$1,489	$250	$331	$678	$1,259	$2,748
11										
12 = SDG&E Transport	$161,606	$19,456	$1,570	$1,178	$183,810	$5,887	$6,181	$12,653	$24,720	$208,530
13										
14 + SoCalGas Transport	$10,164	$3,301	$91	$355	$13,911	$2,864	$3,764	$11,807	$18,455	$32,366
15 + *SoCalGas Storage*	$5,030	$1,013	$21	$86	$6,150	$120	$164	$441	$725	$6,875
16 + Procurement	$55,653	$16,466	$534	$1,452	$74,105	$11,798	$3,376	$67,528	$82,701	$156,806
17 + Interstate PDC	$5,260	$1,788	$50	$164	$7,261	$945	$271	$5,411	$6,627	$13,888
18 + Brokerage Fees	$320	$95	$3	$8	$427	$68	$19	$389	$476	$903
19										
20 = Rate Revenue Allocations	$238,033	$42,119	$2,269	$3,243	$285,664	$21,682	$13,795	$98,228	$133,705	$419,369
21 + *Capped Revenues*	($21,987)	$20,971	$0	$1,016	($0)	($0)	($0)	$1	$0	($0)
22 + *Igniter Adjustments*				($533)	($533)			$533	$533	$0
23 + *UEG/Cogen Parity*							($1,477)	$1,477	$0	$0
24										
25 = Gas Rate Recovery	$216,046	$63,090	$2,269	$3,726	$285,131	$21,682	$12,317	$100,239	$134,238	$419,369
26 + Misc. Revenues	$2,230	$264	$22	$15	$2,532	$81	$71	$120	$272	$2,804
27										
28 Gas Revenue Requirements	$218,276	$63,355	$2,291	$3,741	$287,663	$21,763	$12,388	$100,359	$134,510	$422,173

Cogen	UEG	
$12,317	$100,239	Rate Recovery
$3,376	$67,528	- Procurement
$271	$5,411	- Interstate PDC
$164	$441	- Storage
$8,506	$26,859	= Default Transport $
42,096	1,229	/ Volumes
20.205	2185.472	= Parity Rate

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SOUTHERN CALIFORNIA GAS COMPANY COMPARISON OF CURRENT AND PROPOSED MARGINAL COSTS

Knight - Alternate Decision

MARGINAL COSTS	Units	Proposed	Current [1]
Common Distribution			
Medium Pressure	$/Mcfd of Peak Day Demand	96.85940	102.72429
High Pressure	$/Mcf of Peak Month Demand	0.53750	0.52549
Transmission			
Northern Zone Marginal Cost	$/Dth of Cold Year Throughput	0.06825	0.07258
Base Rate Marginal Cost	$/Dth of Cold Year Throughput	0.09175	0.08946
Zone Rate Credit	$/Dth of Cold Year Throughput	(0.02350)	(0.01687)
Storage			
Inventory:			
Marginal Cost	$/Mcf of Inventory Reservation	0.18323	0.36188
Injection Capacity:			
Marginal Cost	$/Mcfd of Injection Reservation	21.49898	32.04147
Variable O&M	$/Dth of Injection	0.02890	0.04394
Withdrawal Capacity:			
Marginal Cost	$/Mcfd of W/D Res. PD Demand	13.06699	8.55393
Variable O&M	$/Dth of Withdrawal	0.02244	0.01890
Load Balancing:			
Core	$/Dth of Average Year Throughput	N/A	0.00866
Noncore	$/Dth of Average Year Throughput	N/A	0.02115

[1] Current marginal costs are in 1994 dollars, proposed marginal costs are in 1996 dollars.

(END OF APPENDIX D)

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SOUTHERN CALIFORNIA GAS COMPANY

NONCORE REVENUE ALLOCATION

Line	OTHER COST COMPONENTS Forecast Period Costs	OTHER COSTS: ALLOCATION (M$) Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Retail Non-Core Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Total Wholesale Cost	Unbundled Noncore Storage	Total Noncore Cost	Zone Rate Credit Cost
(78)	Subtotal-Transportation Revenue Requirement	97,234	41,581	96,462	32,616	267,893	4,568	52,084	5,536	62,188	20,576	350,657	(8,034)
(79)	Pipeline Demand Charges-EP&TW Trad-Core	-	-	-	-	-	-	-	-	-	-	-	-
(80)	UEG/Cogeneration Parity Adjustment	0	(1,122)	1,122	N/A	(0)	0	0	0	0	0	(0)	0
(81)	SDG&E LTK Reconciliation Account	0	0	0	N/A	0	0	0	0	0	0	0	0
	Transportation Revenue Req w/o N/C Rate Cap	97,234	40,460	97,584	32,616	267,893	4,568	52,084	5,536	62,188	20,576	350,657	(8,034)
(82)	TOTAL TRANS. REV. REQ. w/Cap	97,234	40,460	97,584	32,616	267,893	4,568	52,084	5,536	62,188	20,576	350,657	(8,034)
	Tariffed Rates												
(83)	Total Transportation Costs (Line 46) Less: EOR	97,234	40,460	97,584	N/A	236,277	4,568	52,084	5,536	62,188	20,576	316,042	(8,034)
(84)	Core Averaging	-	-	-	N/A	-	-	-	-	-	-	-	-
	Core Deaveraging Alternative												
(85)	TOTAL TRANS. REV. REQ. w/o EOR	97,234	40,460	97,584	N/A	236,277	4,568	52,084	5,536	62,188	20,576	316,042	(8,034)
(86)	Average Year Throughput (MDth)	122,393	82,483	198,939	N/A	403,815	6,510	108,291	8,692	123,493	N/A	527,308	-
(87)	TARIFFED TRANSPORTATION RATES (¢/th)	7.944	4.905	4.905	N/A	5.826	7.017	4.810	6.369	5.036	N/A	6.031	(0.417)
	* Reflects Partial Core Deaveraging.												
(88)	ITCS Rate (¢/th)	1,300	1,300	1,300	N/A	1,300	1,294	1,294	1,294	1,294	N/A	1,299	
	Gas Purchases & Related Costs												
(89)	WACOG												
(90)	Core Brokerage Fee Adjustment												
(91)	CPGA												
(92)	Carrying Cost Storage Inv. Other (CCSI)												
(93)	Subtotal-Purchased Gas Costs												
(94)	Gas Purchases Cents Per Therm Basis												
(95)	Core Pipeline Demand Charges (SJ Lateral)												
(96)	Core Pipeline Demand Charges (¢/th)												
(97)	TARIFFED SALES RATES (¢/th)												
(98)	Average Year Sales (MDth)												
(99)	CORE SALES REVENUES (M$)												
(99a)	CPGA - Direct Refund												
(99b)	Total Core Sales Revenues w/CPGA Refund (M$)												
(100)	Core Pipeline Demand Reserved for Transport (M$)												

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SOUTHERN CALIFORNIA GAS COMPANY

NONCORE REVENUE ALLOCATION

OTHER COST COMPONENTS		OTHER COSTS: ALLOCATION (M$)												
Line	Forecast Period Costs	Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Retail Non-Core Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Total Wholesale Cost	Unbundled Noncore Storage	Total Noncore Cost	Zone Rate Credit Cost
	Balancing and Tracking Accounts:												
(56)	NGV Account (NGVA)	2,027	1,366	3,295	-	6,688	107	-	143	251	N/A	6,939	-
	Noncore Storage Balancing Account (NSBA)												
(57)	Subscribed Storage Revenue Account	(151)	(104)	(245)	N/A	(497)	(8)	(133)	(11)	(151)	N/A	(648)	-
(58)	Storage Transition and Bypass Subaccount	1,992	1,342	3,237	-	6,571	105	1,754	141	2,000	N/A	8,571	-
(59)	Zone Rate Credit Limitation Memo Acct(ZRCLMA)	(6)	(2)	(4)	-	(11)	(0)	(2)	(0)	(3)	N/A	(14)	-
(60)	N/C Brokerage Fee Balancing Account (BFBA)	44	30	72	N/A	146	2	39	3	44	N/A	189	-
(61)	Interim Zone Rate Credit Account (IZRCA)	8	5	12	-	25	0	7	1	8	N/A	34	-
(62)	Hazardous Substan. Cost Recov. Acct (HSCRA)	877	591	1,425	-	2,893	46	772	62	881	N/A	3,774	-
(63)	Conservation Expense Account (CEA)	(165)	-	-	-	(165)	-	-	-	-	N/A	(165)	-
(64)	R D & D Expense Account (RDDEA)	(558)	(168)	(384)	-	(1,110)	(26)	(230)	(30)	(286)	N/A	(1,395)	-
(65)	Core Fixed Cost Account (CFCA)	-	-	-	N/A	-	N/A	N/A	N/A	N/A	N/A	-	N/A
(66)	1993 BCAP Phase IV Settlement (CFCA)	4,186	N/A	N/A	N/A	4,186	N/A	N/A	N/A	N/A	N/A	4,186	N/A
(67)	Enhanced Oil Recovery Account-Core(EORA)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
(68)	Enhanced Oil Recovery Account-N/C (EORA)	408	123	281	N/A	812	19	168	22	209	N/A	1,021	-
(69)	Minimum Purchase Obligation (MPO)	(803)	(541)	(1,305)	N/A	(2,649)	(43)	(707)	(57)	(806)	N/A	(3,455)	-
(70)	Pipeline Demand Charges (PDC)	-	-	-	N/A	-	-	-	-	-	N/A	-	-
(71)	Carrying Cost of Storage (CCS)	4	3	7	N/A	13	-	-	-	-	N/A	13	-
(72)	Take-or-Pay (TOP)	(262)	(177)	(426)	N/A	(864)	(14)	(231)	(19)	(263)	N/A	(1,128)	-
(73)	Non-Core Fixed Cost Account (NFCA)	136	91	219	N/A	444	7	119	10	136	N/A	580	-
(74)	Non-Core Cost/Revenue Memo Acct(NCRMA)	-	-	-	-	-	-	-	-	-	N/A	-	-
(75a)	Auditing Expense Account (AEA)	-	-	-	-	-	-	-	-	-	N/A	-	-
(75b)	Intervenor Compensation (IN)	-	-	-	-	-	-	-	-	-	N/A	-	-
(75c)	Research Royalty Memorandum Account (RRMA)	(24)	(7)	(16)	-	(47)	(1)	(10)	(1)	(12)	N/A	(59)	-
(75d)	Environmental Fee Account (EFA)	(248)	(75)	(171)	-	(494)	(12)	(102)	(13)	(127)	N/A	(621)	-
(75e)	Fuel Cell Proceeds Memorandum Acct (FCPMA)	(19)	(6)	(13)	-	(39)	(1)	(8)	(1)	(10)	N/A	(49)	-
(75)	Subtotal Balancing and Tracking Accounts	7,445	2,474	5,984	-	15,903	184	1,436	250	1,870	-	17,773	-
(76)	Subtotal-Transportation Revenue Requirement	97,234	41,681	96,462	32,016	267,893	4,568	52,084	5,536	62,188	20,576	350,657	(8,034)
(77)	Subtotal- Transportation Revenue Requirement (¢/th)	7.944	5.041	4.849	-	6.634	7.017	4.810	6.369	5.036	-	6.800	(0.417)

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SOUTHERN CALIFORNIA GAS COMPANY

NONCORE REVENUE ALLOCATION

Line	OTHER COST COMPONENTS Forecast Period Costs	OTHER COSTS: ALLOCATION (M$) Com/Ind Cost	Cogen Cost	UEG Cost	EOR Cost	Total Retail Non-Core Cost	Wholesale Long Beach Cost	Wholesale SDG&E Cost	Wholesale Southwest Gas	Total Wholesale Cost	Unbundled Noncore Storage	Total Noncore Cost	Zone Rate Credit Cost
	TRANSPORTATION REVENUE REQ.												
(40)	Subtotal - Margin - Base	56,689	17,407	38,854	30,992	145,942	2,651	22,362	3,017	28,030	20,576	194,548	(8,034)
	Other Operating Costs and Revenues												
(41)	Exchange Revenues & Interutility Transactions	(117)	(78)	(189)	-	(383)	(6)	(110)	(9)	(125)	N/A	(509)	-
(42)	Core Brokerage Fee Adjustment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
(43)	Noncore Brokerage Fee Adjustment	(175)	(118)	(284)	N/A	(577)	(9)	(156)	(12)	(176)	N/A	(754)	-
(43a)	HUB Revenues Pre 1997	-	-	-	-	-	-	-	-	-	N/A	-	-
(44)	Fuel Cell Equipment Revenues	(16)	(5)	(11)	-	(32)	(1)	(7)	(1)	(8)	N/A	(40)	-
(45)	Company Use Gas: Storage	59	40	96	28	223	33	370	4	407	N/A	630	-
(46)	Other Company Use Gas	117	79	191	56	442	6	103	8	118	N/A	560	-
(47)	Unaccounted For Gas	737	1,231	2,256	1,540	5,764	96	1,225	124	1,445	N/A	7,209	N/A
(48)	Carrying Cost Storage Inv.; Load Balancing	22	15	36	-	72	1	22	2	25	N/A	97	-
(49)	Well Incidents & Surface Leaks	3	2	5	-	10	0	3	0	3	-	13	-
(50)	Pilus Point PPSA & F&U	(32)	(22)	(52)	-	(106)	(2)	(26)	(2)	(32)	-	(139)	-
(51)	Subtotal Other Operating Costs and Revenues	596	1,146	2,046	1,624	5,413	119	1,423	114	1,655	-	7,068	-
	Transition Costs												
(52)	MPO Transition Cost Adjustment	7	5	12	-	24	0	6	1	7	-	31	-
(53)	Pitco/Popco Transition Costs	14,581	9,827	23,701	-	48,109	772	12,842	1,031	14,644	-	62,753	-
(54)	Interstate Trans. Cost Surcharge Accunt (ITCS)	15,913	10,724	25,865	-	52,502	842	14,014	1,125	15,982	-	68,484	-
(56)	Subtotal Transition Costs	30,501	20,556	49,577	-	100,634	1,615	26,862	2,156	30,633	N/A	131,267	-

* Average Year Throughput, Core 10% of PL Demand Cap

PRESIDENT P. GREGORY CONLON, DISSENTING:

I disagree with the majority's viewpoint on how to allocate the costs and benefits of SoCalGas' relinquishment of 750 MMcf/day of interstate pipeline capacity. I am troubled by the logic that was used to reach this conclusion.

SoCalGas' relinquishment significantly reduces, by approximately $50 million per year, the cost of SoCalGas' unsubscribed or underutilized interstate pipeline capacity. [1] Because today's decision retains the core reservation policies we adopted in D.91-11-025 and D.92-07-025, the entire benefit of this $50 million reduction will benefit SoCalGas' non-core customers.

In contrast, the corresponding costs associated with these relinquishments, approximately $150 million spread out over about five years, are allocated approximately 2/3rd to core customers, and 1/3rd to non-core customers. These costs relate to settlements entered into by SoCalGas with the interstate pipelines (El Paso and Transwestern), to ensure that the pipelines would not try and reallocate any of the costs of the relinquished capacity back on to SoCalGas by increasing the cost of the remaining capacity held by SoCalGas.

Under my proposed alternate decision on this issue, I had advocated treating the costs associated with the settlement as transition costs associated with interstate pipeline capacity to be collected through the Interstate Transition Cost Surcharge (ITCS). Under this approach, non-core customers would have paid most, perhaps even all, of the costs associated with the step-downs but also would have received all of the benefits. The assignment of costs with benefits is a fundamental tenet of ratemaking.

[1] SoCalGas' demand charges associated with this pipeline capacity less revenues received from brokering this capacity.

In the public debate over this item, several of my colleagues recognized that non-core customers received most of the benefits and that core customers paid most of the costs but believed that there were offsetting benefits that, although unquantified, could entirely offset the costs that the core would be paying.

It is this contention that I find troubling. The majority appears to believe that you can take a dollar from one customer, give it to another customer, and that in doing so somehow the economy will grow at such a level that the first customer gets more than his entire dollar back in reduced costs or increased wages. In order for this to be true, it would require an economic multiplier effect significantly greater than any we have ever seen. I think it is useful to note that the representatives of the core customers, the alleged direct beneficiaries of the approach advocated by the majority, do not share their enthusiasm for this economic theory. I am not sure that any of this argument is on the record of this proceeding.

I am very sympathetic to the need to create a good business climate for California. I agree with the tenets of economic theory that the total size of the economy can be affected by the allocation decisions that we make today. It is a far larger, and unsupportable, leap of faith that <u>all</u> customers will be better off under this approach. As I noted in my comments at the Commission meeting, the BCAP is a zero-sum game. Every dollar in costs allocated to one class of customers is a dollar less that those customers have to purchase goods and services. The majority overlooks the inter-relationships of our economic system. They appear to focus primarily on the role of business as a provider of goods and services, and ignore the now reduced purchasing power of the consumer who we must rely on to purchase those very same goods and services.

Finally, although the majority have categorized today's debate as between business and consumers, they overlook that the vast majority of Southern California businesses are small enough to be core customers. It is these types of businesses that are playing a major role in Southern California's economic recovery, and that are being hurt by today's decision.

A number of other arguments were also raised as to why core customers should pay for a portion of the costs related to the settlement of the relinquishment issues. As discussed below, I do not find merit in these arguments.

Consistency with Capacity Brokering Decisions

Some have argued that the approach adopted today is consistent with our previous capacity brokering decisions (D.91-11-025 and D.92-07-025). Nowhere in these decisions is there justification for the allocation method adopted today. These Commission decisions have clearly and consistently chosen to define the costs associated with obligations that existed prior to the gas industry restructuring as transition costs and to allocate them as such, regardless of whether these costs are incurred as surcharges, direct bills, or demand charges.

Reduced Transwestern Demand Charges

In comments on the proposed decision, parties have raised the argument that the core benefits from the stepdowns through lower transportation rates (exclusive of the surcharges) on the Transwestern and El Paso systems. This argument overlooks that the settlements covered a number of other issues (GRC revenue requirements, take-or-pay issues, unbundling of gathering facilities) in addition to the stepdown issue. Much of the reduction in Transwestern demand charges, for example, can be attributed to efforts that were on-going and predated the settlements. The unbundling of gathering charges and the phase-out of certain take-or-pay charges are examples of this. No party has presented convincing evidence that the resolution of the stepdown issue, as a part of the larger settlement, resulted in the cost to ratepayers being either lower (or higher) than they otherwise would have been.

Flow-through of PG&E Relinquishment Costs

A third argument, is that a significant portion of the settlement costs are related to interstate capacity on the El Paso system that was not held by SoCalGas, but that was being relinquished by PG&E. There are several problems with this argument. First, in its GRC filing at FERC, El Paso never proposed to reallocate any of its costs associated with the PG&E step-down to SoCalGas. Instead, El Paso sought to recover these costs directly from PG&E through an exit fee, a position that FERC rejected (79 FERC 61,028, mimeo at p. 2). Second, in order to try and justify a benefit to core ratepayers, proponents of this argument assume an unlikely and worst-case scenario that all of the costs of the relinquished capacity would have been reallocated back to SoCalGas. Finally, this argument assumes that some portion of SoCalGas' current surcharge payments to El Paso are related to the PG&E relinquishment. As FERC itself found in approving the El Paso settlement, PG&E's own contribution of $58.4 million to the settlement "does much to protect the remaining customers from the impact of PG&E's contract termination." (79 FERC 61,028, mimeo at p. 2). Thus it is unclear, how much of SoCalGas' El Paso settlement costs are related to PG&E's relinquishment.

San Francisco, California
May 2, 1997

P. Gregory Conlon

P. GREGORY CONLON,
President