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Decision 82 04 116 APR 28 1982

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY and PACIFIC LIGHTING GAS SUPPLY COMPANY to Increase Revenues Under the Consolidated Adjustment Mechanism to Offset Changed Gas Costs Resulting from Increases in the Price of Natural Gas Purchased from EL PASO NATURAL GAS COMPANY, TRANSWESTERN PIPELINE COMPANY, PACIFIC INTERSTATE TRANSMISSION COMPANY, PACIFIC GAS AND ELECTRIC COMPANY and California sources; to Adjust Revenues to Recover the Undercollection in the CAM Balancing Account; to Reflect in the CMA Balancing Account Costs Related to Franchise Fees and Uncollectible Expense and Increased Carrying Costs on Natural Gas Stored Underground; and to Revise Section II of the Preliminary Statement of the Tariffs.	Application 60867 (Filed September 4, 1981)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY FOR Authority to Increase its Gas Rates and Charges Pursuant to its Proposed Consolidated Adjustment Mechanism.	Application 60901 (Filed September 15, 1981)

In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY and PACIFIC LIGHTING GAS SUPPLY COMPANY to Increase Revenues Under the Consolidated Adjustment Mechanism to Offset Changed Gas Costs Resulting From Increases in the Price of Natural Gas Purchased from El Paso Natural Gas Company, Transwestern Pipeline Company, Pacific Interstate Transmission Company, Pacific Gas and Electric Company and California sources; to Adjust Revenues to Recover the Undercollection in the CAM Balancing Account; to Reflect in the CAM Balancing Account costs Related to Franchise Fees and Uncollectible Expense and Increased Carrying Costs on Natural Gas Stored Underground; and to Revise Section H of the Preliminary Statement of the Tariffs.	Application 82-03-16 (Filed March 5, 1982)
In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY FOR Authority to Increase its Gas Rates and Charges Pursuant to its Filed Consolidated Adjustment Mechanism.	Application 82-03-38 (Filed March 9, 1982)

(Appearances are listed in Appendix A.)

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OPINION

I. Summary

In these consolidated gas offset applications, we are asked to authorize increases in natural gas rates for SoCal and SDG&E to offset increased purchased gas costs from their respective suppliers. SoCal originally requested approval of rate increases which would provide $1.289 billion in additional revenues; this request was subsequently revised to $1.106 billion. Our decision today grants SoCal additional rate relief of about $834.3 million.

Since SDG&E purchases gas from SoCal under wholesale Schedule G-61, the rate relief granted SoCal will have a direct and immediate impact upon SDG&E's operations and expenses. To recover the increased costs of its gas supplies and to amortize under- and overcollections in the PGA and SAM balancing accounts, we will authorize SDG&E to increase rates to generate additional revenue of $66.3 million.

In addition to authorizing rate increases for SoCal and SDG&E, today's decision addresses several significant economic issues and establishes policies in the following areas:

(1) The appropriate rate design guidelines for SoCal;

(2) An appropriate economic test for new long-term gas supply projects, and

(3) An appropriate economic test for short-term discretionary gas purchases.

The rate design guidelines adopted today are based upon the premise that gas customers should pay as close to the utility's marginal supply costs as revenue requirement constraints and minimization of fuel switching allow. The most efficient allocation of gas resources should occur when the customer pays the marginal or resource cost of gas.

The adopted guidelines move toward accomplishment of this goal. Since adoption of rates completely based on marginal costs would collect more revenues than SoCal requires, the guideline rates invert residential rates while pricing the lifeline rate at less than marginal cost to solve the overcollection problem.

In order to provide a useful supply planning tool for SoCal, the Commission adopts an economic test for determining the prudency of new long-term gas supply acquisitions. If the net cost of the new gas supply at the California border should exceed the cost of imported crude delivered to California refiners over the life of the gas supply project, failure by SoCal to demonstrate that it considered the economic test in the planning, negotiating, and certificating phases of acquiring the new gas supply will create a presumption that the new gas supply purchases are imprudent.

The Commission also adopts an economic test to apply to the purchase of discretionary volumes of gas under existing supply contracts. In adopting rate design guidelines for SoCal, a "marginal rate" was developed. The "marginal rate" is developed by considering:

(1) A reasonable price for discretionary purchasers;

(2) The variable cost of the most expensive gas supply; and

(3) The price of alternate fuels such as 0.25% and 0.5% low sulfur fuel oil and #2 distillate oil.

All these elements are relevant to an economic test for discretionary purchases. The marginal rate, which this decision establishes in a range from 51.7¢/th to 52.6¢/th, will provide an adequate benchmark for making a threshold determination of whether a certain discretionary supply purchase is prudent or not. If discretionary purchases are made at prices in excess of the marginal rate, a presumption is created that such purchases are imprudent.

Finally, with respect to SDG&E's rates, the staff's recommended rate design, with two exceptions, is adopted. First, the lifeline rate is maintained at 80% of the system average cost. Secondly, the staff's recommended GN-5 rate is lowered to 50.5¢/th. The GN-5 rate, which covers sales from SDG&E's gas department to its electric department, was revised downward to mitigate some of the impact of today's authorized gas rate increase upon SDG&E's electric customers.

PROCEDURAL HISTORY

On September 4, 1981, Southern California Gas Company (SoCal) and Pacific Lighting Gas Supply Company (PLGS) filed Application (A.) 60867, seeking Commission authority to increase their natural gas rates by about $790 million. Since San Diego Gas & Electric Company (SDG&E) purchases gas from SoCal under wholesale Schedule G-61, SoCal's request for rate recovery of purchased gas costs has a direct and immediate impact upon SDG&E's operations and expenses. Accordingly, on September 15, 1981, SDG&E filed its application to increase its gas revenues by $56.7 million to reflect the increased G-61 rate proposed by its supplier, SoCal. Given the clear interrelationship, A.60867 and A.60901 were consolidated for hearing.

On September 24, 1981 in Los Angeles, public hearing was held to review the requests of both SoCal and SDG&E for interim authority to increase their gas rates and charges collected through their respective Consolidated Adjustment Mechanisms (CAM). Subsequently, SoCal filed affidavits indicating that certain Federal Energy Regulatory Commission (FERC) actions had resulted in a tentative decrease in its $790 million request to $715 million. SoCal sought interim relief at 80% of that amount, or $572 million. Correspondingly, SDG&E revised its request downward and asked for interim relief at 80% of $38.1 million, or $30.5 million.

On October 20, 1981, the Commission issued Decision (D.) 93629 granting interim increases to SoCal of $572 million and to SDG&E of $30.5 million, both subject to refund. All other substantive issues, including rate design, were reserved for resolution in the final order in the consolidated applications. Further hearings were set for November and December. The rate design issue engendered controversy and required considerable hearing time. Hearings continued for 21 days, finally concluding on February 26, 1982. Seventy-three exhibits were received in evidence. The consolidated applications were finally submitted, subject to the filing of concurrent briefs on March 17, 1982. Briefs were filed by SoCal, SDG&E, Southern California Edison Company (Edison), the City of Long Beach (Long Beach), Tehachapi-Cummings County Water District (Tehachapi), California Farm Bureau Federation (Farm Bureau), California Ammonia Producers, California Manufacturers Association (CMA), General Motors Corporation (GM), Toward Utility Rate Normalization (TURN), Regents of the University of California (UC), Pacific Gas and Electric Company (PG&E), Department of General Services (DGS), and the Commission staff (staff).

On March 5, 1982, prior to the issuance of a Commission decision in A.60867 and 60901, SoCal filed its April, 1982 CAM, A.82-03-16. SDG&E followed suit and filed A.82-03-38 on March 9, 1982. Once again the two matters were consolidated for hearing. Public hearings on these consolidated applications were held from March 22 through March 25, 1982. After oral argument by applicants, interested parties, and the Commission staff, A.82-03-16 and 82-03-38 were submitted on March 25, 1982.

All four of the above-referenced applications will be consolidated, and we will publish one decision disposing of all matters raised by the four applications. We are now prepared to issue our decision.

INTRODUCTION

Today's decision will consist of two major components. The first component involves SoCal's A.60867 and 82-03-16 and the issues which they have raised. The second component addresses SDG&E's A.60901 and 82-03-38 and the issues generated by their filing.

Our review of SoCal's applications will focus on the following issues:

1. The authorized revenue requirement to recover past undercollections and projected costs for the CAM forecast period of April 1, 1982 to March 31, 1983.

2. The appropriate rate design for spreading the revenue requirement among SoCal's customers; and

3. The appropriate economic tests for determining the reasonableness of long-term gas supply projects and short-term discretionary purchases.

Our review of SDG&E's applications will resolve the following issues:

1. The authorized revenue requirement to recover costs associated with SDG&E's CAM and Supply Adjustment Mechanism (SAM) for the forecast period of April 1, 1982 to March 31, 1983; and

2. The appropriate rate design for spreading the revenue requirement among SDG&E's customers.

II. SoCal's A.60867 and A.82-03-16

A. Revenue Requirement

1. SoCal's Position

A.82-03-16, as originally filed, requested Commission approval of rate increases which would provide $1.289 billion in additional revenues for SoCal. However, on March 23, 1982, the FERC took action on filings made by the out-of-state suppliers of SoCal and PLGS-El Paso Natural Gas Company (El Paso), Transwestern Pipeline Company (Transwestern), and Pacific Interstate Transmission Company

(Pac Interstate). As a result of the FERC action, SoCal submitted evidence which revised its revenue requirement request downward to $1.106 billion.

The requested $1.106 billion increase in revenue requirements is prompted by the following elements: (a) increased costs for basic purchases from present supply sources, (b) costs of best efforts purchases from PG&E and Michigan Consolidated (Mich-Con), and (c) revenue required to recover CAM undercollection of April 30, 1982 and the carrying cost of increased value of gas in storage, including franchise fees and uncollectible accounts (F&U).

SoCal's amended showing indicates that El Paso's and Transwestern's revised tariffs will increase the cost of gas to SoCal for the 12-month period commencing April 1, 1982 by about $693 million. The cost of Transwestern gas will increase by about $300 million for the test period. Included in this increase is $53 million due to a general rate increase which became effective February 28, 1982. The increased cost of El Paso gas is about $393 million during the forecast period. This increase includes $82 million for 9 months of El Paso's general rate increase which becomes effective July 1, 1982. In addition, Pac Interstate's revised tariff will increase the cost to PLGS by about $1 million. The total cost increases from basic supply sources, which include federal offshore, California, and Pan-Alberta source gas, are about $707 million or 64% of the total claimed revenue requirement.

The cost of PG&E and Mich-Con best efforts gas amounts to about $194 million. This cost is reduced by $182 million due to increased sales at current rates. Thus, the increased revenue requested for these purchases is approximately $12 million.

SoCal also seeks authority to adjust its rates to amortize the CAM balancing account undercollection estimated to total about $153 million by April 30, 1982. This date was selected in anticipation of a Commission decision in mid-April. The inclusion of the April 30 estimated balance in the revenue requirements projection was intended to provide a more accurate representation of conditions closer to the decision date and will reduce overall cost to customers by reducing interest. SoCal proposes to amortize the estimated April 30 undercollection over a 6-month period. Such an amortization of the CAM undercollection would produce an annual revenue requirement of $346.4 million.

SoCal also seeks recovery through its CAM for certain costs which are currently pending before the Commission in A.60339. SoCal requests recovery of $8.5 million in carrying costs related to the increased value of natural gas in storage over adopted test year levels. Furthermore, SoCal proposed in A.60339 that a balancing account be authorized to ensure that no more or no less than the actual incurred franchise fee expense and uncollectible accounts expense is collected in rates. Authorization of this request and its inclusion in the current CAM would increase the revenue requirement by about $26 million.

In sum, SoCal's requested revenue requirement of $1.106 billion was derived as follows:

		M$
1.	Cost of Gas Purchased	4,270,423
2.	CAM Balance Annualized*	346,379
3.	Subtotal	4,616,802
4.	Associated F&U Expense @ 1.7275%	79,755
5.	Gas Margin	752,188
6.	Primary Revenue Requirement (Lines 3 + 4 + 5)	5,448,745
7.	Revenue at Present Rates	4,377,826
8.	Revenue Requirement Excluding Revenues Pending in A.60339 (L6-L7)	1,070,919
9.	Revenue Pending in A.60339	
	a. Carrying cost of storage	8,466
	b. Prior period F&U annualized	25,651
	c. Associated F&U (L9a + 9b x 1.7275%)	589
10.	Subtotal	34,706
11.	Total Revenue Requirement	1,105,625

*CAM balance estimated as of April 30, 1982.

2. Staff Position

Staff recommends that an additional revenue requirement of $834,294,000 be authorized for collection by SoCal through its CAM. Staff's estimate of $834,294,000 is $271,331,000 less than the $1,105,625,000 requested by SoCal. The reasons for the lower staff recommendation are as follows:

a. Carrying cost of Storage Inventory - SoCal includes a revenue requirement of $8,466,000 to recover the carrying cost on an increase in the value of gas stored underground based on the difference between the value of such gas established in SoCal's 1981 general rate case and its estimated forecast period value. The issue of whether or not SoCal should be authorized to recover carrying costs on the value of gas stored underground on a current basis is now before the Commission in A.60339. Accordingly, staff does not include such costs in its recommended revenue requirement.

b. SoCal's estimated revenue requirement includes $25,651,000 to recover an undercollection of franchise fees and uncollectible expenses for the period August 12, 1978 through September 17, 1979. This issue, as is the case with carrying costs of storage inventory, is pending in A.60339 and is not included in staff's recommendation.

c. CAM Balancing Account -- The SoCal revenue requirement includes the effect of amortizing its April 30, 1982 undercollections ($153,401,000) over a six-month period, resulting in a revenue requirement of $346,379,000. The staff-estimated revenue requirement attributable to CAM undercollections is developed using the estimated March 31, 1982 CAM balance of $89,358,000 amortized over the six-month period beginning April 1, 1982. The resulting revenue requirement is $201,770,000 on an annual basis.

d. Cost of Gas - SoCal's estimate of the cost of gas purchased from El Paso includes the effects of El Paso's general rate increase application which under FERC procedures is scheduled to become effective on July 1, 1982. The CAM procedures established by the Commission do not permit SoCal to reflect in current filings the effects of FERC increases which are to become effective subsequent to the revision date. SoCal's request for authorization to reflect such costs in the revenue requirement is effectively a request for a deviation from the tariff procedures. SoCal's estimated revenue requirement also includes an increase in the cost of transporting the Pan-Alberta gas on the El Paso system occasioned by the July 1, 1982 El Paso general increase. The effect of including only those rate increases effective on or before the revision date results in a staff-estimated revenue requirement to offset increases in the cost of gas that is approximately $88 million less than SoCal's estimates.

The staff's recommended revenue requirement of $834,294,000 was tabulated as follows:

		M$
1.	Cost of Gas	4,182,533
2.	CAM Balance Annualized*	201,770
3.	Subtotal	4,384,303
4.	Franchise Fees & Uncollectibles (Line 3 x 1.7275%)	75,739
5.	Gas Margin	752,188
6.	Subtotal Revenue Requirement	5,212,230
7.	Revenue at Present Rates	4,377,936
8.	Additional Revenue Requirement (Line 6 - Line 7)	834,294

*CAM balance estimated as of March 31, 1982.

3. TURN's Position

TURN raises three points with respect to the revenue requirements issue. First, TURN supports the staff recommendation to exclude future gas cost increases, such as the July 1, 1982 El Paso general rate increase, in determining the ultimate revenue requirement for SoCal's April 1982 CAM.

Secondly, TURN urges the Commission to adopt a 12-month amortization of the balancing account. If the staff-recommended revenue requirement were revised to provide a 12-month amortization of the CAM balancing account, the additional revenue requirement for SoCal would total $719,940,000. TURN admits that such an approach is not without risk and further acknowledges that a 12-month amortization would stretch out the recovery of costs and potentially leave some hundred million dollars for recovery in SoCal's October 1982 CAM proceeding. However, in light of the enormous increase sought by SoCal and given the possibility that El Paso's and Transwestern's undercollections might be amortized by the next CAM proceeding, TURN argues that delay of SoCal's undercollection recovery through the annual period could actually result in rate stability, with a smaller increase now and the possibility of minimal increases in October.

By its third recommendation TURN asks the Commission to disallow $2,883,000 in unnecessarily and imprudently incurred gas costs. During October 1981, SoCal purchased the contract minimum daily quantity of Pan-Alberta gas. Purchase of the 2,598 MMcf of Pan-Alberta gas forced the rejection of an equal amount of lower-cost El Paso supply. TURN contends that proper planning and foresight by SoCal could have avoided rejection of the El Paso gas.

The pipeline capacity constraint that produced this problem will occur anytime El Paso is delivering full contract quantities to both SoCal and PG&E. In order to avoid similar El Paso rejections in the future, SoCal's transportation affiliate, Pac Interstate, applied to the FERC on October 15, 1981 for authority to use an alternative route for Pan-Alberta supply. Had such permission been obtained prior to October 1981, the rejections in that month would not have been required.

The "reasonableness" question facing this Commission is whether SoCal should reasonably have anticipated the possibility of capacity constraints and acted to obtain FERC approval of the Pacific Gas Transmission (PGT)/PG&E route prior to the beginning of the actual gas flow on October 1. TURN believes that the evidence is overwhelming that SoCal should have had this minimal degree of foresight.

According to TURN since there is no valid reason beyond simple negligence for SoCal's failure to obtain advance approval for the PGT/PG&E route, so the $2,883,000 cost of the resulting El Paso rejections must be disallowed from the CAM balancing account as an unnecessary and imprudent gas cost.

4. Discussion

We find the staff's recommended additional revenue requirement of $834,294,000 to be reasonable, and we will adopt it. We agree with the staff adjustments to SoCal's projected revenue requirement increases for the CAM forecast period. Issues pending in A.60339, i.e. carrying costs on the increased value of gas in storage and recovery of certain past period franchise fees and uncollectible expenses, will be resolved in a separate decision issued today. In computing the authorized additional revenue requirement, we also find it more appropriate to use balancing account information as of March 31, 1982 rather than April 30, 1982. The March 31 estimate reflects a predominance of recorded information and tracks actually incurred costs more closely than SoCal's recommendation which includes estimated costs for April, 1982. We have previously stated our preference for use of recorded rather than estimated data in calculating balancing account undercollections and overcollections. No sufficient rationale for departure from this practice has been presented.

With respect to the calculation of gas costs, we do not think it is appropriate to allow SoCal to reflect in the current filings the effect of FERC increases which will become effective subsequent to the April 1, 1982 CAM revision date. The tariff is clear, and the current situation does not warrant deviation from its terms. We acknowledge that in typical circumstances the effect on the CAM balancing account of excluding increases in gas costs scheduled to become effective between the April 1 and October 1, 1982 revision dates is the accumulation of undercollections in the CAM balancing account. Such undercollections can serve to increase the costs passed on to the consumer in SoCal's next CAM above the level that would result from any increases in supplier rates approved by the FERC in October, 1982.

However, there are circumstances in the current proceeding which militate in favor of allowing such undercollections to accrue. Specifically, there is a large component in the forecast period costs to recover past period undercollections. In effect, rates authorized to produce additional revenues of $834,294,000 will contain a large component in rates which is significantly above the rates necessary to recover currently incurred costs. The importance in the instant case is that the authorized rates, with the component in excess of current costs, will provide an offsetting effect to increases in the cost of gas to SoCal that may occur between SoCal's April and October revision dates. Therefore, we find staff's method for calculating gas costs appropriate.

We are sympathetic to TURN's request for 12-month amortization of the CAM balancing account. Particularly in this time of economic difficulty and limited resources, we seek to be alert to viable alternatives which might lead to lower rates for customers. However, we do not believe that adoption of a 12-month amortization period is in the best interests of either the ratepayer or SoCal. Irrespective of its effect on the utility's cash flow, a 12-month amortization would inevitably result in the accrual of large undercollections with attendant increases in interest costs. It was just this failure to amortize past undercollections in a timely fashion which has contributed to the size of the increase we are compelled to grant today. We would not be doing the ratepayer a favor by slightly mitigating the impact of today's rate increase through adoption of a 12-month amortization period while ensuring another large increase in gas rates in SoCal's October CAM. Instead, we will adopt a 6-month amortization of the CAM balancing account in the hope that such an action will result in minimal gas rate adjustments in the October CAM.

Finally, we will defer action on TURN's request to disallow $2,883,000 gas costs as imprudently incurred. Rather, we will reserve review of that issue for SoCal's October 1982 CAM proceeding. Staff has recommended that an annual reasonableness review be adopted for SoCal's CAM. We will adopt the staff recommendation. The review period shall be the 12-month period ending one month prior to the revision date. During its review SoCal will be expected to submit its daily operating records as part of its reasonableness showing. During SoCal's October CAM, the reasonableness of SoCal's past purchases for the period September 1, 1981 through August 31, 1982 will be the subject of Commission inquiry. At such time, TURN's allegation of imprudence will be given full scrutiny. We will note in passing that during hearing on the consolidated applications TURN moved to defer consideration of reasonableness issues until the October 1982 CAM. The stipulated motion was granted, and we will ratify that ruling by today's action.

B. Rate Design

1. SoCal's Proposal

From the outset of these consolidated proceedings, SoCal has steadfastly maintained that generic consideration of rate design issues is most properly addressed in general rate proceedings. However, in response to a ruling by the administrative law judge that consideration of new rate design concepts was appropriate in the CAM proceeding, SoCal presented its proposed rate design guidelines, along with supporting evidence. SoCal's recommended rate design guidelines are as follows:

(1) A two-part wholesale rate: (a) the monthly fixed charge based on the percentage of margin-related costs (excluding any costs related to conservation activities) allocated to the wholesale customers in the Base Supply and Load Equation Cost Allocation Study, approved in the last general rate case; (b) the commodity charge based on the system average cost of gas (including the applicable cost of discretionary gas supply purchases), plus amounts to reflect the wholesale customer's share of franchise fees and the cost of gas portion of the CAM balancing account.

(2) GN-3, GN-4 and GN-5 rates referenced to the price of 0.5% sulfur #6 fuel oil with the rate to GN-5 not to exceed 80% the cost of 0.25% sulfur #6 fuel oil. It is recommended that the three-cent differential between GN-36/46 and GN-32/42 rates be eliminated.

(3) Average residential, GN-1 and GN-2 rates referenced to a price which is at least 2 cents per therm above the GN-3 rate established prior to the allocation of any discretionary gas supply purchase; maintain customer charges at current levels.

(4) Lifeline rate referenced to the average cost of gas excluding discretionary purchases plus at least 2 cents per therm; excess block of the residential rate at the highest rate on the system not to exceed the highest variable cost of gas.

(5) The cost of discretionary gas supply purchases allocated to those classes of customers which experience reduced curtailment because of such purchases as indicated in the average temperature forecast year gas balances, as long as no other guidelines are violated.

The sequence of steps taken in determining the guideline rates is as follows:

<u>Step 1</u> - Adopt a revenue requirement, sales figure and a reference price for 0.5% sulfur #6 fuel oil. Also determine a revenue requirement and sales figure excluding discretionary purchases.

<u>Step 2</u> - Determine wholesale rates and revenues according to guideline (1) above and subtract the wholesale revenue from the total revenue requirement (excluding the cost of discretionary purchases) to derive the retail revenue requirement.

<u>Step 3</u> - Set the GN-3, 4, and 5 rates at the 0.5% sulfur #6 fuel oil reference price.

Step 4 - Set the average residential, GN-1 and GN-2 rates 2 cents per therm above the GN-3, 4, and 5 reference price. Set any special rates such as Ammonia Producers rates.

Step 5 - Determine if the rates in Steps 3 and 4 collect the retail revenue requirement excluding discretionary purchases;

(a) If an overcollection results, reduce all retail class rates on an equal cents-per-therm basis and allocate the cost of discretionary purchases to those customers experiencing reduced curtailment as a result of those purchases up to the 0.5% sulfur fuel oil reference price for P-3 and P-4 customers and 80% of the weighted average cost of 0.25% sulfur #6 fuel oil for GN-5 customers; and

(b) If an undercollection results, increase average residential GN-1 and GN-2 rates on an equal cents-per-therm basis to collect the revenue requirement and allocate the cost of discretionary purchases to those customers experiencing reduced curtailment as a result of those purchases as long as no other guidelines are violated.

Step 6 - Within the residential class, generally attempt to maintain existing rate relationships and,

(a) Set the Tier III rate at the highest variable cost of gas on the system;

(b) Set the lifeline rate at the average cost of gas excluding discretionary purchases plus 2 cents-per-therm; and,

(c) Set the Tier II rate residually.

Step 7 - Check all rates to determine if the rates exhibit stability from period to period.

The critical element of SoCal's rate design is the establishment of a reference price for 0.5% sulfur #6 fuel oil which is used to set the rates for GN-3, 4, and 5 sales. SoCal strongly urges the Commission to set rates for P-3 and P-4 customers so that those rates do not exceed the low end of the price range for those customers' alternate fuels. If P-3 and P-4 rates are set at the high end of the price range for alternate fuels, substantial fuel switching by P-3 and P-4 customers, in addition to potential loss of considerable sales, would almost certainly result. It is unlikely that utility electric customers can absorb any significant amounts of gas made available to them as a consequence of fuel switching by P-3 and P-4 customers since the sales forecast for the P-5 customers assumes almost the complete displacement of oil by gas.

Because P-5 customers could not likely absorb any significant amounts of the additional gas made available to them, the only alternative would be for SoCal to cut back on purchases from PG&E, Mich-Con, and Transwestern. Because PG&E's price is lower than any retail rate SoCal proposes in the April CAM, with the exception of the Ammonia Producers rate, fuel switching by P-3 and P-4 customers would cause a margin undercollection since SoCal would not have PG&E gas to sell at rates in excess of its cost. Every therm of less expensive PG&E additional gas not taken contributes to a revenue under-collection that must be made up from those classes, i.e. P-1, P-2, and possibly a few P-3 and P-4 customers, remaining on the system. In turn, such fuel switching and loss of load would result in higher balancing account deficits and higher rates for high priority customers.

The evidence in this proceeding indicates that alternate fuel oil is available for purchase at the low end of the price range. Furthermore, crude oil prices are currently falling, not rising. Since fuel oil is available for purchase at the low end of the range, whenever natural gas rates to P-3 and P-4 customers rise above that low end, some of those customers may switch to their alternate fuel. SoCal requests the Commission to reference lower priority rates to the low range of 0.5% sulfur #6 fuel oil which currently approximates 44¢/th to 51¢/th.

SoCal argues as follows: Its rate design guidelines are clear and easy to apply. By contrast, staff witness Cavagnaro's proposed guidelines are so subjective that two individuals applying his guidelines might very well come up with entirely different rate schedules. The process of setting a lifeline rate and a "marginal" rate under Cavagnaro's guidelines requires so much judgment that staff rate design experts are incapable of doing so independently. From the standpoint of ease of application, SoCal's proposed rate design guidelines are preferable and produce a much more objective result.

Additionally, SoCal's guidelines are designed to retain P-3 and P-4 customers on the utility system because those customers provide an economic benefit to the system, i.e., their rates result in a positive contribution to the fixed costs of the system. To the extent those customers leave the utility system and switch to alternate fuels under present circumstances, higher priority rates will increase. Under Cavagnaro's proposed guidelines, the benefits of keeping P-3 and P-4 customers on the system would most likely be lost through fuel switching.

Finally, SoCal's proposed guidelines are equitable in that the same rate design criteria are used to establish rates to all retail customer classes. SoCal's proposed guidelines reference rates for P-1 and P-2 customers to the same price as rates for P-3 and P-4 customers, plus a premium for the higher value of firm service. However, that premium has a limit. It would not be retained beyond the point where the lower priority customers ceased contributing to the fixed costs of the system.

Presented below is an illustration of rates which application of SoCal's proposed rate design guidelines to its requested revenue requirement of $1,105,625,000 would produce. Illustrative rates based upon a revenue requirement of $923,812,000, which assumes use of March 31, 1982 CAM balancing account undercollections, are also provided for comparison.

Class of Service	Present Rates (1-1-82)	($1,105,625,000 Rev. Req.) Guideline Rates	($1,105,625,000 Rev. Req.) Guideline Rates Adjusted**	($923,812,000 Rev. Req.) Guideline Rates	($923,812,000 Rev. Req.) Guideline Rates Adjusted**
RESIDENTIAL					
Lifeline*	28.297	45.578	43.729	43.498	40.653
Tier II	38.177	55.578	53.729	53.498	50.653
Tier III	56.721	75.578	73.729	73.493	70.653
Total Residential		55.658	53.809	53.578	50.733
COMMERCIAL-INDUSTRIAL					
GN-1	38.177	55.658	53.809	53.578	50.733
GN-2	38.177	55.658	53.809	53.578	50.733
G-COG	45.767	49.000	52.000	49.000	52.000
GN-32/42	44.654	49.000	51.000	49.000	51.000
Scattergood Unit #3	45.767	48.149	52.000	48.149	52.000
GN-36/46	41.654	49.000	49.000	49.000	49.000
GN-5	45.767	48.149	52.000	48.149	52.000
Ammonia Producers	35.319	43.478	43.478	43.478	43.478
WHOLESALE					
Long Beach	32.431	40.456	40.456	40.456	40.456
San Diego	32.431	40.350	40.350	40.350	40.350

* Customer charge of approximately 6.6¢/th not included.

** Three adjustments were made from the guideline rates determined in steps 1 through 6. First, the 3-cents-per-therm-differential between GN-32/42 and GN-36/46 rates was lowered to 2 cents per therm so that it would be phased out over time and not all at once. Second, in the same way, the differential between GN-5 and other lower priority rates (i.e., GN-3 and GN-4) was decreased but not eliminated. Third, historical relationships were used to set the rates in the various residential blocks. That is, a 10-cent per therm differential was maintained between lifeline and Tier II and a 20-cent per therm differential between Tier II and Tier III.

2. Staff's Proposal

Staff witness Cavagnaro, testifying on behalf of the Policy and Planning Division, proposes rate design guidelines that would set rates for customer classes as close to marginal supply cost as possible, after consideration is given to lifeline and Ammonia Producers rates. In a period of rapidly escalating gas prices and a soft oil market, Cavagnaro maintains that correct price signals are critically needed. The most efficient allocation of gas resources should occur when gas customers pay as close to the utility's marginal supply costs as the constraints of revenue requirement and potential fuel switching will allow. Since application of full marginal cost rates would generate revenues in excess of SoCal's requirement, Cavagnaro suggests use of what he terms a "marginal rate" as the foundation for establishing gas rates.

The marginal rate would be established once a year by the Commission during SoCal's annual reasonableness review.1/ Development of the marginal rate would be based upon consideration of the following elements: (1) a reasonable price for discretionary purchases;2/ (2) the variable cost of the most expensive gas supply, and (3) the price of 0.25% and 0.5% low sulfur fuel oil and the price of #2 distillate oil. The marginal rate is the central element of the proposed rate design guidelines and would be used to set rates for all customer classes with the exception of lifeline, Tier III residential sales, and the initial block for GN-1 and GN-2 customers.

1/ Such a rate would not be calculated with mathematical certainty, but rather judgment would be applied to various factors to develop a limited range for the marginal rate. For this proceeding only, the marginal rate was derived mathematically since fuel switching and economic studies necessary for its development were unavailable.

2/ This issue is addressed in subsequent portions of the decision.

In setting rates, Cavagnaro's rate design guidelines would be implemented in the following sequence:

1. A marginal rate is established;
2. The marginal rate is used to calculate the resulting revenues for the GN-1 and GN-2 quantities in excess of 300 therms, the residential Tier II quantities, and the GN-5 quantities;
3. The initial 300-therm block of the GN-1 and GN-2 rate is set at 5¢/therm below the GN-1 and GN-2 excess quantity rate;
4. The Tier III residential rate is set at 10¢/therm above the Tier II rate;
5. The lifeline rate is set residually at a level between 15% and 25% below the average system rate; and
6. In the event the above calculations produce an excess or deficiency in the revenue requirement, each rate is to be adjusted downward or upward on a uniform ¢/therm basis.

The virtue of Cavagnaro's rate design is that it moves nearly all gas rates, at the same pace, toward a rate level recognized in economic theory as optimal pricing for maximum efficiency in resource allocation--i.e., marginal cost. Those rates which are not set at the marginal rate, in order to avoid collection of excess revenues, are set at rate levels consistent with strong social policy objectives. For example, Cavagnaro recommends that the lifeline rate be set within a range of 15-25% below the average system rate consistent with the intent of Public Utilities (PU) Code Section 739. Additionally, Cavagnaro recommends that Tier III residential rate be set at 10¢/therm above Tier II rate, and that the GN-1 and GN-2 initial blocks be set 5¢/therm less than the excess quantity rates, in order to encourage conservation through inverted rates.

Application of Cavagnaro's guidelines to produce an additional revenue requirement of $882,527,000 would result in the following illustrative rates:

(¢/therm)

	Present Rates	Guidelines D.L. 20% Below	CCA+ GEDA	Illustrative Rate	Increase %
Lifeline*	35.0¢	38.8¢	1.0¢	39.8¢	13.7%
Tier II	38.2	52.1	1.0	53.1	39.0
Tier III	56.7	62.1	1.0	63.1	11.3
Avg. Resid.	38.2	44.4	1.0	45.4	18.8
GN 1/2 Initial	38.2	47.1	1.0	48.1	25.9
GN 1/2 Excess	38.2	52.1	1.0	53.1	39.0
C-COG	45.8	52.1	0.1	52.2	14.0
GN 32/42	44.7	52.1	1.0	53.1	18.8
Scattergood	45.8	52.1	0.1	52.2	14.0
GN 36/46	41.7	52.1	1.0	53.1	27.3
GN 5	45.8	52.1	0.1	52.2	14.0
NH 3	35.3	42.5		42.5	20.4
Total Retail	41.5	49.4	0.7	50.1	20.7
Avg. Wholesale	33.8	41.7	0.1	41.8	23.7
Avg. System	40.7	48.5	0.6	49.1¢	20.6%
<u>Below Sys. Avg.</u>					
Lifeline	14%	20%		18.9%	
Residential	6.1%	8.5%		7.5%	

*Including customer charge of approximately 6.6¢/th.

During the hearings on the consolidated applications, both SoCal and staff were asked, for purposes of comparison and in an effort to forecast the future trend of rate levels, to apply their respective rate design guidelines to SoCal's forecasted revenue requirement needs for January 1, 1983. Both SoCal and staff assumed a January 1, 1983 total revenue requirement of $5,514,704,000.[3]

3/ By contrast, the total revenue requirement sought by SoCal in these proceedings is $5,483,461,000. The staff's recommended total revenue requirement is $5,212,230,000.

The rates developed are as follows:

	1983 Forecast Guidelines	
	Staff Rates	SoCal Rates
	(¢/th)	
Residential		
Lifeline*	43.7	56.5
Tier II	58.5	59.8
Tier III	68.5	79.8
Average Residential	49.7	60.3
Commercial-Industrial		
GN-1 and GN-2		
Initial	53.5	60.3
Excess	58.5	60.3
Average	57.6	60.3
GN-36/46	58.5	50.5
G-COG	58.5	50.5
GN-32/42	58.5	50.5
Scattergood	58.5	49.6
GN-5	58.5	49.6
Ammonia Producers	43.7	-
Total System	53.9	53.9
Wholesale	41.0	38.2
Lifeline below System Average	20.0%	4.8% (abv)
Residential below System Average	8.0%	11.9% (abv)

*Includes customer charge of approximately 6.6¢/th.

Staff counsel contends that the above-referenced tabular comparison demonstrates a clear preference for Cavagnaro's proposed guidelines. It is staff counsel's position that SoCal's guidelines are nothing more than an attempt to have firm customers subsidize interruptible customers' gas purchases. Staff counsel argues that SoCal's rate design proposal amounts to a scheme whereby SoCal can continue purchasing gas at any cost by charging firm customers more and more as the price of gas is driven above SoCal's recommended 0.5% sulfur fuel oil reference price. This result can readily be seen from the application of SoCal's guidelines to the forecasted January 1983 revenue requirements. By January 1983, even with a forecast of oil prices increasing 4.6% from current prices, SoCal's guidelines would require the firm customers to pay about 10¢/therm more than interruptible retail customers, and about 20¢/therm more than wholesale customers. Moreover, in this example the lifeline rate is set higher than the GN-5 rate even without including the customer charge, and is above the GN-3 and 4 rates when the customer charge is included.

Staff also challenges SoCal's assertion that substantial fuel switching will occur if interruptible rates are not set at the low range of prices for 0.5% sulfur fuel oil. No probative evidence was presented in support of SoCal's contention. Staff maintains that in the event of fuel switching to 0.5% sulfur fuel oil in any significant degree it is quite likely that stricter air quality restrictions will be imposed to require P-3 and P-4 customers to burn more expensive 0.25% sulfur fuel oil. Furthermore, SoCal presented no credible evidence indicating whether its customers had any air quality permit restrictions which would prevent them from burning #6 fuel oil, or whether there were end-use limitations on P-3 and P-4 customers in SoCal's service area which might prevent them from switching to oil, or whether SoCal's interruptible customers would be willing to pay a premium for gas above 0.5% sulfur fuel oil.

Finally, staff disputes SoCal's claim that any fuel switching would cause an increase in the rates to firm customers. The following example shows why 20% fuel switching could potentially lead to a reduced revenue requirement.

1. Assume P-3 and P-4 sales are at 1,463 M^2 therms.
2. Assume that the staff's recommended rate of 58.5¢/therm, as opposed to SoCal's recommended rate of 50.5¢/therm, causes a 20% loss in the P-3 and P-4 market.
3. The revenue obtained from SoCal rates would be:

   1463 x 50.5 = $739 million.
4. The revenue obtained from staff rates would be:

   1170 x 58.5 = $685 million.
5. Thus there would be $54 million less collected in rates because of the 20% reduction in P-3 and P-4 sales.
6. There would also be 293 M^2 therms less discretionary gas purchased, causing a reduction in the cost of purchased gas as follows:

   a. 153 M^2 Therms (Pan Alberta) x 55.6 = $85 million

   b. 140 M^2 Therms (PG&E) x 47.6 = $67 million

   total = $152 million
7. The revenue requirement for other than P3/4 customers would thus be reduced by $98 million ($152 million decreased costs less $54 million in decreased revenues).

Thus, in this example the effect of a 20% loss of the P-3 and P-4 market because of gas rates set above the 0.5% reference price--a totally speculative assumption until a fuel switching study is developed to show that this would be the result--is a net savings to other customers of $98 million. It can be therefore seen that SoCal's effort to raise the specter of massive fuel switching and system load loss is completely speculative and insufficient reason for rejecting Cavagnaro's proposed rate design guidelines.

The other staff member who made rate design recommendations was Mr. Fowler, who testified for the Commission's Gas Branch. His recommendation is to use existing Commission guidelines and modify them to take account of the fact that during the forecast period Pan-Alberta supplies will primarily benefit the P-5 customers. Fowler also contends that since PG&E gas will be purchased to serve the P-5 customers, they should bear those costs as well. Thus Fowler recommended that in establishing the GN-5 rate the full commodity cost of Pan-Alberta gas and PG&E discretionary gas should be allocated to these customers benefiting from this supply. Additionally, Fowler notes that since 42% of wholesale customers' purchases are for P-5 sales, the commodity rate for the wholesale customer should be bifurcated, one rate for sales for P-1 through P-4 use, the other to cover P-5 use. Fowler justifies these departures from existing guidelines on the grounds that the Commission stated in the Pan-Alberta decision that it was interested in seeing "a rate design ... which more closely correlates the actual costs and actual benefits experienced by a class or classes of customers as a result of the Pan-Alberta additions." (D.93370, p. 46.)

3. <u>TURN's Position</u>

TURN supports the Cavagnaro rate design proposal and its promotion of conservation, efficiency, and equity. Citing PG&E's D.93887 in which the Commission noted with approval the benefits of marginal cost pricing, TURN maintains that Cavagnaro's proposal is the next logical step in the Commission's implementation of marginal cost pricing for natural gas.

TURN also defends Cavagnaro's use of marginal supply costs while excluding marginal distribution, transmission, and storage costs. TURN notes that the Commission has previously adopted marginal supply costs in its recent Edison D.92549 and PG&E D.93887. Despite SoCal's stated objection to the use of only marginal supply costs, a proposed exhibit from SoCal's pending general case, which was received in evidence in these proceedings, indicates that SoCal ~~itself assumes its marginal transmission, distribution, and storage costs to be zero.~~

TURN also counters the time-worn argument that marginal cost pricing theory cannot be applied when marginal costs exceed the revenue requirement. The Commission has for several years adopted appropriate reconciliation procedures with respect to electric rates, and it can surely do the same with gas. Cavagnaro's approach requires first setting the lifeline rate, including customer charge revenue, at a percentage discount from the system average rate. This method is certainly consistent the intent of the lifeline legislation. All other rates are then set as close to marginal costs as the revenue requirement permits.

This treatment, in combination with the inverted residential rate structure, provides all customers with a strong conservation price signal. Since 76.1% of residential gas sales go to customers who exceed their lifeline allowances 4/, consumers in this class face marginal rates equivalent to those of the other classes. Both the Residential Conservation Service (RCS) cost-effectiveness calculations and the Energy Commission's building and appliance efficiency standards consider the marginal rates faced by customers. Inverted rates increase the cost-effectiveness of conservation investments from the customer's point of view. Classes which do not have inverted rates face a marginal rate that is the same as their average (flat) rate.

Contrary to arguments raised by SoCal that the Cavagnaro proposal is subjective and confusing, TURN finds the procedure clear and straightforward. After wholesale and Ammonia Producers rates are set according to formula, the lifeline rate, including customer charge revenue, is established in a range of 15-25% below the system average rate, with 20% below as a starting point. The "marginal rate" for the other schedules is then derived mathematically, with adjustments for the residential third tier (10¢ above the marginal rate) and the GN-1 and 2 first block (5¢ below the marginal rate). Any two people performing the calculations should come up with identical results.

4/ Based on 1980 consumption by single-family residences in Zone 1, which contains over 90% of total class sales. Since 1980 was a warm year, the average year percentage facing the marginal rate would be even higher.

Cavagnaro also proposed a moderate inversion in the GN-1 and GN-2 rates, under which the first 300 therms would be priced 5¢/therm below the marginal rate. Such inversion permits the marginal rate for all classes to be moved closer to marginal cost, while providing a small amount of relief to hard-pressed small businesses. Since the maximum value of the "discount" is only $15 per month, problems of discrimination among competitors are not seriously raised. Realistically, this proposal does no more than level out the effective declining block rate created by the monthly customer charges in these schedules. TURN supports the Cavagnaro recommendation in its entirety.

4. Edison's Proposal

Edison asserts that over the many years modern regulation of public utilities has been in existence, these fundamental regulatory principles have evolved:

> 1. A primary objective of rate regulation is to protect consumers from exploitation which can result from "what-the-market-will-bear" pricing.
>
> 2. To prevent such exploitation by the serving utility, regulatory bodies have over the years determined the total revenue requirement (including a reasonable return on investment) on the basis of costs ascertained under generally accepted accounting principles, and not on the basis of "alternate fuel prices," "marginal costs," "avoided costs" or other esoteric economic theories.
>
> 3. To prevent such exploitation as between customer classes, the normal starting point in establishing just and reasonable rates--determined in the accounting sense--for each of the customer classes is on the basis of the cost of rendering that service to that class, and not on the basis of "alternate fuel prices," "marginal costs," "avoided costs" or other esoteric economic theories.

In July 1977, the Commission in D.87587—with the objective of gas conservation—discarded as the benchmark fully allocated average cost of service and since that time has instead applied an alternate fuel price "referencing" criterion as the basis for setting gas rates by SoCal to retain electric utilities such as Edison. The Commission justified its "radical restructuring" of gas rates to the GN-5 electric utilities on the ground that if:

> "We were to allow unrealistically low gas prices, it would be a cruel hoax; for industry would be lulled into a false sense of security and be disruptively shaken and set back when the day of drastic increases...arrives." (82 CPUC at p. 197.)

Edison maintains that the result has been almost five years of what-the-traffic-will-bear gas pricing for GN-5 electric utilities and other industrial customers, with a concomitant subsidy of SoCal's residential gas customers. Edison points to evidence that the subsidy (i.e., the disparity between CPUC-authorized GN-5 rates and SoCal's allocated cost of service to GN-5 customers) created by the Commission's inverted gas rate policies adopted in 1977 will aggregate for Edison alone about $580 million by the end of 1981 (about 1/3 of all Edison ECAC increases during 1977-1981) and could aggregate as much as $800 million by the end of 1982.

Edison argues that the Commission's own rate design policies have now perpetrated that cruel hoax on SoCal's residential customers, who have been lulled into a false sense of security by unrealistically low gas prices. Now with rapidly rising gas prices and a softening oil market, the Commission—having essentially imposed all that the traffic will bear upon the GN-5 electric utilities—must face the prospect in upcoming SoCal proceedings of imposing the bulk of the increases on those residential customers. SoCal—faced with significantly softening oil prices which could continue for a number of years in the future—is only able to propose a 13.5% increase to GN-5 customers in an effort to preserve the market and consequently must now place the bulk of its additional revenue requirement burden on the residential and P-1 and P-2 commercial and industrial customers. SoCal's proposal calls for nearly a 50% increase to those customer classes.

During the course of SoCal's gas rate proceedings over the years, Edison has argued that allocated cost of service should be used as the benchmark for rate design for all customers. Edison again urges the Commission to abandon its "alternate fuel pricing" gas rate design and to return to using allocated cost of service as the benchmark for rate design on the SoCal system.

If, however, the Commission is disposed to continue in effect the substance of its "alternate fuel pricing" rate design for the GN-5 electric utilities served by SoCal, Edison urges the Commission to take the following steps:

1. The GN-5 rate ceiling to Edison should be reduced from 80% to 76% of the cost of alternate fuel oil, so that Edison can pay the costs associated with using unanticipated supplies of gas (such as underlift charges) and still realize an economic advantage from burning such gas.

2. Moreover, if the Commission is disposed to attribute for rate design purposes SoCal's highest cost gas supply, e.g., Pan-Alberta, to electric utilities, both Long Beach and SDG&E--which make considerable P-5 sales--should bear their fair share of that cost burden. In the mid-1970s, when P-5 supplies were short, the Commission established the principle of "parity of P-5 supply" as between P-5 end users whether served directly or indirectly (through wholesale customers) by SoCal. That parity of P-5 supply

> principle should be applied to any rate design criterion which would attribute a high cost supply to P-5 end users.

Both GM and CMA concur with Edison that fully allocated cost of service is, at a minimum, the appropriate starting point for the establishment of just and reasonable natural gas rates. They also agree that marginal cost concepts of gas rate design lead to distortions of economic theory, to inequities between customers, to adverse impacts on the economy, and do not produce as much conservation as rates which are based on fully distributed costs.

GM as well as the Farm Bureau also strongly object to the proposed inversion of the GN-1 and GN-2 rates. GM, with particular interest in the GN-2 rate, argues that the inverted rate proposal lacks any rational foundation and blatantly discriminates against the larger customers served under Schedules GN-1 and GN-2. Furthermore, the assumption underlying the adoption of inverted rates for residential gas customers, i.e., the discouragement of wasteful gas use, does not pertain to customers served under Schedule GN-2.

The preferable course of action, and that which GM urges upon the Commission, is that it require a showing as to the impact of an inverted rate structure featuring a more realistic break-point before it considers further any move in the direction of inverted rates for nonresidential gas customers.

5. <u>Position of SDG&E and Long Beach</u>

SDG&E participates in SoCal's proceedings on behalf of its ratepayers. The costs which the Commission assigns to SDG&E through SoCal's Schedule G-61 are in turn passed on to SDG&E ratepayers in SDG&E's CAM proceedings. The current Commission guideline calls for Schedule G-61 to include a single commodity rate based on the average cost of gas plus SoCal's GEDA rate. This guideline was developed after extensive testimony and argument by SoCal, SDG&E, and the staff in A.59316, leading to D.92497 of December 5, 1980. The guideline adopted in that general rate case decision has since been followed in D.93190 of June 16, 1981 and also in D.93269 of October 20, 1981 (the first interim decision in this proceeding). SDG&E submits that current guideline, or formula, for setting wholesale rates should be retained for Schedule G-61 because it serves to equitably allocate revenue requirement to SDG&E as efficiently as possible.

Long Beach concurs with SDG&E that it is appropriate to continue to design wholesale commodity rates which are based upon the system average cost. Further, Long Beach recommends that the refund-recollection factor of $.00215 included in the Long Beach wholesale rate by virtue of D.93190 be eliminated effective October 1, 1981.

Long Beach also supports, and SDG&E does not dispute the staff position that wholesale customers should participate in the purchased gas adjustment (PGA) balancing account. It would be inappropriate for other customers on SoCal's system to bear any portion of the actual cost of gas delivered to wholesale customers for resale to their customers. Since wholesale customer sales result in franchise fee payments by SoCal, Long Beach agrees that it is reasonable for SoCal to receive reimbursement of those costs on either an actual or an appropriate percent basis.

Both SDG&E and Long Beach object to the staff proposal to allocate uncollectible costs to wholesale customers. Uncollectible expenses are incurred by every distribution utility system. Since each of SoCal's wholesale customers experience retail service uncollectibles on their respective systems, they are recovered from all retail customers on their system. To take the position of staff, i.e. that wholesale customers should share in SoCal's uncollectible expense, is asking all retail customers of SDG&E and Long Beach to pay for SoCal uncollectible accounts and SDG&E's and Long Beach's uncollectibles. This would be inequitable and result in retail customers of Long Beach and SDG&E paying twice for uncollectibles.

6. Proposals of DGS and UC

DGS proposes that the Commission adopt a cogeneration incentive gas rate in the form of a 5¢/therm fixed reduction in the otherwise applicable SoCal rate. This proposed incentive rate would be proportional to the incentive rate originally established by the Commission in D.91239 and 92792.

In its original decisions, the Commission allowed cogenerators to pay the electric utility gas rate. This action created a price reduction for cogenerators that averaged approximately 3¢/therm among the State's three large gas utilities.

Recently, it has become increasingly apparent that the cogeneration incentive rate is eroding. Under SoCal's proposed rate changes there would be no incentive whatsoever for cogenerators since the GN-5 rate would be higher than either the GN-32/42 or GN-36/46 rates. At the time of D.91239 and 92792, few could have predicted this proposed serious alteration of GN-5 rates from the lowest gas rate to one of the highest. Given the probability of such an alteration, DGS argues that a new incentive rate mechanism is needed to preserve the concept originally adopted by this Commission.

DGS seeks to prevent the erosion of cogeneration incentives by proposing a mechanism whereby the incentive calculation is derived from the cogenerator's applicable rate instead of the electric utility gas purchase rate. DGS further recommends that the original approximate 3¢/therm incentive be replaced by a 5¢/therm incentive. This apparent increase in the incentive rate reflects the difference between gas prices in 1980 and 1982 (30¢/therm vs. 50¢/therm). Due to inflation, this revised incentive rate would actually be unchanged in real dollar terms. Thus, DGS' proposal requests that the Commission adopt a new measure that sets the cogeneration incentive at 5¢/therm to directly reduce the cogenerator's otherwise applicable gas rate. If such an incentive gas rate is not approved, the economic feasibility of planned state cogeneration projects will be severely impaired.

UC recommends that the Commission diversify its encouragement and incentive for cogeneration development by establishing a truly incentive cogeneration facility natural gas rate. Such a natural gas rate should be independent of the electric utility gas rate since that latter rate is now subject to "new criteria." UC recommends establishment of a special tariff schedule for cogeneration gas rate, set at a premium discount of 3¢/therm below the gas rate otherwise applicable to the cogenerator. Such a tariff schedule would clearly provide an encouragement for every potential cogenerator without regard to its current tariff schedule, and would be the same incentive for every potential cogenerator. Such a "fixed cents per therm rate" below the otherwise applicable commercial-industrial gas rate would also provide certainty to the potential cogenerators' attempt to predict the necessary payback period for the capital investment associated with a cogeneration facility.

7. Position of Los Angeles Department of Water and Power (DWP)

Both SoCal's and Cavagnaro's proposed GN-5 rates pose a dilemma for DWP. DWP has a four-year contract for an alternate fuel (0.25% sulfur content fuel oil) at a gas equivalent price of 49.5¢/therm. Additionally, it is entirely possible that the price of this alternate fuel may drop to as little as 42¢/therm (gas equivalent price) within the next six months. The proposed GN-5 rate of 52¢/therm for natural gas is significantly higher than the present or expected price of fuel oil, and higher yet than the 40.5¢/therm cost to SoCal of providing DWP its gas service.

The result is a radical departure from historical trends. DWP is now faced with a situation wherein economic incentives may favor the use of fuel oil in lieu of available natural gas as the primary fuel for DWP's steam-electric generating plants located in the South Coast Air Basin. The resulting negative impact on the flexibility of the gas supply system and the degradation of air quality in the South Coast Air Basin were discussed at length during the proceedings before this Commission.

DWP plans to await the Commission's GN-5 rate signal prior to any further fuel procurement action. However, if the proposed GN-5 rate is placed into effect without further consideration of the economic factors raised by DWP, then the escalating costs of supplying reliable electrical service to DWP's customers will necessitate a reevaluation of DWP's existing policy of displacing fuel oil with natural gas whenever the latter is available.

8. <u>Ammonia Producers' Proposal</u>

PU Code Section 741 specifies that the gas rates to Ammonia Producers can be no higher than the average price paid by the utility for gas from all suppliers, plus 10%, and no lower than the rate in effect on December 31, 1979. The Ammonia Producers have proposed a rate equal to SoCal's average cost of gas, excluding purchases from the Pan-Alberta project and excluding PG&E discretionary gas, plus 10%. In the hearings following interim D.93629, they presented evidence that such rate, at 32.37¢/therm, would unquestionably compensate SoCal for the gas supplied, and for SoCal's other costs, including a fair rate of return. The Ammonia Producers presented evidence that with a charge of 32.37¢ they have a reasonable chance of covering their own costs and operating on an economically viable basis. The Ammonia Producers' proposed rate reflects the fact that for the foreseeable future SoCal's Pan-Alberta purchases and its PG&E discretionary purchases, while resulting in increased supplies to other customers, will have no such effect on the Ammonia Producers.

9. Tehachapi's Proposal

Tehachapi sells water both for agricultural and municipal purposes. It uses 16 engines driven by natural gas to import water from the State Water Project to Tehachapi. Every 5¢/therm is equivalent to about $25 of gas cost per acre foot. As such, Tehachapi is a large purchaser of gas from SoCal, and has a direct interest in rate design.

Tehachapi recommends that a lower rate structure than any of the proposed GN-2 rates should be provided to priority customers who pump water for ultimate sale to the public, whether that water purveyor is a public utility, a public entity, or a mutual water company. Tehachapi submits that the pumping of water for uses by customers normally served by public utilities should be set at a lower rate so that the inverted rate schedule for domestic services can extend to domestic service of water. It is conceded that it is impractical to separate out the end uses in this regard. The same basic argument can be made for agriculture. Tehachapi asserts that implementation of Commission policy on water lifeline rates, as well as consistency with the territory of SoCal and Edison, indicates that rates for pumping water for ultimate use through water purveyors (and agriculture) should be set at approximately 10% below the rate which the average residential customer pays per therm. This would mean 34.616¢ minus 3.46¢ or 31.156¢/therm.

In any event, the GN-2 rate should be equated to the average cost per therm sustained by SoCal's average residential customer. The Commission, for some time, has been establishing GN-1 and GN-2 rates at the same rate as the second tier domestic rate. Implicit in this is some kind of assumption that rates are being equalized between GN-1 and GN-2 customers and residential customers, whereas, in fact, as of October 21, 1981, the GN-1 and GN-2 customers were paying over 3¢ more per therm than the average residential customer. Since, by any calculation of cost of service, GN-1 and GN-2 customers, and particularly GN-2, have a lower cost of service than residential and perform essential functions for the economy, Tehachapi urges that GN-1 and GN-2 rates be made equal to the rate paid by the average residential customer and not the average of the three tiers of domestic rates and not equal to the middle tier.

10. Discussion

The problems posed by the need to design rates which will generate the adopted additonal revenues of $834,294,000 are exceedingly difficult. Residential customers and businesses, both large and small, have testified that they have reached the limit of gas costs they can reasonably bear. Edison and DWP state that any further gas rate increases may well cause them to reject gas volumes in favor of fuel oil. Tehachapi, the Ammonia Producers, and the cogenerators all request a lower gas rate to serve their unique needs. CMA, GM, as well as Edison, request gas rates based on a fully allocated cost of service, with the attendant consequence of raising the current average residential rate by about 50 to 80% in one fell swoop.

Unfortunately there are no simple solutions to the problems occasioned by constantly escalating gas rates, and the contrasting interests of the various affected classes of customers cannot be reconciled. As gas prices move inexorably higher in accordance with the provisions of the NGPA, no class of SoCal's customers will be insulated from the increases. In response to this situation, we find it more appropriate to develop a uniform rate design policy applicable to all classes rather than a piecemeal, ad hoc response to the special needs of individual classes of customers.

Our review leads us to reject the rate design guidelines proposed by SoCal and the fully allocated cost of service rates recommended by Edison. We agree with TURN that there is little logic in a rate proposal, like SoCal's, which uses as a critical reference point the price of 0.5% sulfur fuel oil, a fuel that no one is currently using and that in all probability could not be burned on any regular basis given air quality constraints. SoCal's guidelines appear to be an effort to impose the increased costs of gas on high priority customers while insuring that there will be a minimal loss of system load occasioned by the fuel switching of P-3, P-4, and P-5 customers.

SoCal contends that massive fuel switching will occur, with resulting increased costs to high priority customers, if its guidelines are not adopted. SoCal failed to adequately support its contention. Despite repeated and long-standing requests to SoCal by the staff for an analysis of P-3 and P-4 customer air quality permits to determine which customers could switch to fuel oils, SoCal has failed to provide useful or complete information. This must be viewed as a failure to meet its burden of proof.

With respect to the request of Edison and CMA for fully allocated embedded cost of service, we have previously concluded that it is not a meaningful measure in setting gas rates. Price signals based on the cost of facilities constructed long ago are counterproductive in a period of rapidly escalating energy supply costs. It is inappropriate to mask the signal of the cost of new gas supplies with such costs.

In D.91720 at pages 19-20 we addressed the use of fully allocated cost of service at considerable length:

> "These proponents of 'cost of service' insist and persist in spreading gas costs on a uniform cents per therm basis in their studies. This allocation method is unreasonable in view of the gas priority system and the different prices paid different suppliers. We find such studies to be of no probative value in setting gas rates.
>
> "Any attempt to calculate a meaningful 'cost of service' must reflect the low priority status of industrial boiler fuel customers and the variable nature of gas supply. To the extent that gas supply is a function of price, the cost of gas to serve low priority customers includes not only the commodity cost of the specific gas sold to those customers, but also the incremental cost of the gas sold to high priority customers above the price that would be sufficient to produce enough supply to serve only high priority demand. This principle is crucial in analyzing the transition from a regulated to an unregulated market, as in gas supply."

Our language contained in SoCal's D.90822 issued September 12, 1979 is also equally apposite today:

> "SoCal's gas mix comes from several sources, with different prices. The highest priced gas SoCal purchases is required to serve the lowest priority customers. Accordingly, the application of the strict average system cost of service as the sole criterion for pricing gas to SoCal's low priority customers is without merit. Further, it is necessary for low priority customers both to bear the cost of the incrementally higher

> priced gas SoCal purchases to serve them and to receive a realistic price signal as to the current cost of energy. By receiving such a price signal these large customers can reassess their usage requirements and have a true incentive to tailor their operations to the most efficient use of energy." (2 Cal PUC 2d 340, at p. 367.)

Edison contends that the Commission's inverted gas rate policies have caused Edison to subsidize SoCal's residential gas customers in the amount of $580 million by the end of 1981, which could aggregate as much as $800 million by the end of 1982. However, the notion of a "subsidy" is only as good as the assumptions which underlie it. Edison assumes that every dollar charged above its formulation for cost of service constitutes a "subsidy". One can posit a situation in which SoCal's residential customers are subsidizing Edison's electric customers. Assume that Pan-Alberta supplies are delivered solely to provide service to Edison and other P-5 customers. Since the cost of Pan-Alberta gas exceeds the rate at which it is sold to Edison, gas customers can arguably assert that they are subsidizing Edison's operations. We find that the notion of "subsidy" depends on perspective and provides us with little guidance in establishing just and reasonable rates. Consistent with our previous positions, we will reject fully allocated costs of service as an anachronism.

Our analysis of the various rate design proposals leads us to conclude that the Cavagnaro proposal, with minor modifications, represents the preferable approach. We agree with the fundamental premise underlying Cavagnaro's guidelines that gas customers should pay as close to the utility's marginal supply costs as revenue requirement constraints and minimization of fuel switching allow.

Traditional economic theory concludes that a price set at marginal cost achieves the optimum equalization of the current cost to society of employing scarce resources and the value to consumers of using those resources. In terms of economic efficiency, the advantage of marginal cost pricing for regulated utilities is that it serves as a means of encouraging the maximum economic use of the utility's services. We agree that the most efficient allocation of gas should occur when the customer pays the marginal or resource cost of gas. Cavagnaro's guidelines move toward accomplishment of this goal.

Since the marginal cost of new gas supplies exceeds SoCal's average costs, some gas must be priced at less than the average cost if other gas is priced at or near the marginal cost in order to avoid overcollection of SoCal's revenue requirement. Cavagnaro's guidelines present a solution which is both consistent with the promotion of conservation and the intent of the Legislature. The guidelines invert residential rates while pricing the lifeline rate (including customer charge revenue) at less than marginal cost. The nonlifeline residential rates and the low priority rates are then set at levels approximating marginal cost.

The Legislature has mandated the provision of lifeline rates and Cavagnaro's proposal is consistent with that directive. Furthermore, there is an additional reason to treat lifeline rates as a special case within an overall marginal cost pricing policy. In order to avoid overcollection of the utility's revenue requirement caused by collection of full marginal cost rates, economic theory permits deviation from marginal costs in inverse proportion to the elasticity of demand for the utility service of various classes of customers. Previously, in D.91720 in Finding 35, we have found that "conservation potential within the lifeline sales is relatively slight."

With an inverted residential rate and all other rates set as close to marginal cost as the revenue requirement permits, all customers are provided a strong conservation price signal. It is acknowledged that the proposed residential rates may not produce the maximum conservation from that class. Certainly a residential gas rate of $1.00/therm might produce more conservation, if that were our only consideration. However, given consideration of other rate design factors, such as efficiency and equity, we find that the conservation signal given by Cavagnaro's guidelines is both adequate and appropriate. As TURN notes, 76.1% of residential gas sales go to customers who exceed their lifeline allowances and thus receive the conservation signal provided by a rate equivalent to the marginal rate faced by other classes of customers.

Rate design guidelines based upon a marginal cost theory will develop rates that will produce conservation and efficiency, two of the three primary goals of an effective rate design. The third goal is equity. Cavagnaro's guidelines provide uniform rates for all classes of customers, except lifeline and special customer classes, such as wholesale customers and the Ammonia Producers. Nothing could be more equitable than to provide the same price signal to all classes of customers.

One aspect of Cavagnaro's guidelines we will not adopt is his proposal to invert the GN-1 and GN-2 rate by pricing the first 300 therms of consumption at 5¢/th less than the excess quantities. We agree with GM that a further showing is required before we adopt inverted rates for nonresidential gas customers. While the maximum value of the discount contemplated by Cavagnaro's proposed inversion of the GN-1 and GN-2 totals only $15/month, it represents a significant departure from previous policy and deserves more scrutiny--especially with respect to the proper volume for inclusion in the initial block.

Adoption of Cavagnaro's rate design guidelines, except for the recommended inversion of the GN-1 and GN-2 rates, would produce the following rates when applied to the authorized total revenue requirement of $5,212,230,000:

Classification	Guideline Rates (¢/th)	GEDA (¢/th)	CCA (¢/th)	Proposed Effective Rates (¢/th)
Residential				
Tier I*	31.935	.145	.808	32.888*
Tier II	51.663	.145	.808	52.616
Tier III	61.663	.145	.808	62.616
Total	44.147			
Commercial-Industrial				
GN-1/-2	51.663	.145	.808	52.616
GN 32/42	51.663	.145	.808	52.616
GN 36/46	51.663	.145	.808	52.616
Scattergood	51.663	.145	-	51.808
GN-5	51.663	.145		51.808

*Rate does not include customer charge of approximately 6.6¢/th.

The proposed rates call for an increase of 16.2% over the current level of the lifeline rate. Since the total increase we are authorizing today produces a system average rate increase of 19.9%, we think it is appropriate to adjust Cavagnaro's guidelines to reflect a 19.9%, or system average, increase for lifeline. Such an adjustment will produce a lifeline rate of 33.928¢/th. To maintain the appropriate level for revenue requirement, we will revise the proposed Tier II and GN-1/-2 rates downward by .925¢/th. We take this action to mitigate some of the impact upon these classes of customers of our transition to application of a marginal rate.

Adoption of Cavagnaro's guidelines does not entirely resolve the rate design issues. Consistent with the statutory mandate, we will adopt a rate for the Ammonia Producers based upon the average cost of all SoCal's gas suppliers plus 10%. This results in a rate of 42.582¢/therm for the Ammonia Producers. Such a rate will only exceed the rates adopted for lifeline and wholesale customers. We feel this is consistent with the statutory mandate. If the Ammonia Producers are not satisfied with this treatment, their request for the lowest rate on the system should, once again, be made to the Legislature.

In establishing a wholesale commodity rate for Long Beach and San Diego, we will continue use of the guideline established in D.92497. The rate is developed by using SoCal's average cost of gas plus SoCal's Gas Exploration and Development Adjustment (GEDA) rate. Since retail customers of SDG&E and Long Beach pay for such a component in their own rates, we will reject the request to include a component in the wholesale rate to account for uncollectible expenses. We will add one refinement. We will adopt a component in the rate to account for franchise fee costs incurred by SoCal as a result of wholesale customer sales.

It is also appropriate to eliminate the $.00215 refund recollection factor contained in the Long Beach wholesale rate. These refund factors should have been eliminated as of October 1, 1981. During the period, October 1, 1981 to the present, SoCal has been overcollecting from Long Beach to the extent the $.00215 factor remained in rates. However, during the same period, SoCal experienced undercollections from Long Beach which tend to more than offset any overcollection. Therefore, we will take no other action than elimination of the refund factor.

The wholesale rate of 39.455¢/th for SDG&E and Long Beach is computed as follows:

SoCal's average cost of gas	38.711¢/th
Franchise fee (38.711¢/th x 1.5462%)	.599¢/th
<u>GEDA Factor</u>	.145¢/th
Wholesale Rate	39.455¢/th

Finally, a balancing account for wholesale customers to recognize deviations from the adopted average cost of gas and the recorded average has been proposed. We denied a similar request in D.93190 issued June 16, 1981. No new evidence was presented to support a change in position. We are already awash in balancing accounts. The mere fact that recorded figures may differ from estimated numbers is insufficient to warrant further proliferation of these accounting devices.

We are not inclined to create a further gas rate incentive for cogenerators. We will continue to reference the cogenerators' rate to the rate charged steam electric customers. Since the steam electric rate is being moved toward the marginal rate, any action to discount the cogeneration rate below the reference rate would be inconsistent with avoided cost concepts and marginal cost pricing theory.

Our adoption of Cavagnaro's rate design guidelines as revised, as well as our resolution of the remaining rate design issues, when applied to the authorized total revenue requirement of $5,212,230,000 -- an increase of $834,294,000 over current revenues -- will produce the following rates:

Classification	Sales (MMth)	Guideline Rates (¢/th)	Revenue (MM$)	GEDA (¢/th)	CCA (¢/th)	Effective Rates (¢/th)
Residential						
Customer Charge			138.6			
Tier I	2,085.5	32.975	687.7	.145	.808	33.928*
Tier II	699.9	50.738	355.1	.145	.808	51.691
Tier III	362.5	61.663	223.5	.145	.808	62.616
Total	3,147.9	44.147	1,389.7			
Commercial-Industrial						
Customer Charge			13.2			
GN-1/-2	1,644.9	50.738	834.6	.145	.808	51.691
G-COG	31.6	51.663	16.3	.145	-	51.808
GN 32/42	577.3	51.663	298.2	.145	.808	52.616
GN 36/46	795.6	51.663	411.0	.145	.808	52.616
Scattergood	157.1	51.663	81.2	.145	-	51.808
GN-5	3,069.0	51.663	1,585.5	.145		51.808
NH_3	168.6	42.582	71.8	-	-	42.582
Total	6,444.1		3,327.0			
Retail	9.592.0	49.173	4,716.7			
Wholesale						
G-60 Cap			3.4	-		
G-60 Comm**	266.4	39.310	104.7	.145	-	39.455
G-61 Cap			13.6		-	
G-61 Comm**	941.2	39.310	370.0	.145	-	39.455
Total	1,207.6		491.7			
System Total	10,799.6		5,208.4			
Exchange			3.8			
Total Sales			5,212.2			

* Rate does not include customer charge of approximately 6.6¢/th.

In contrast to the currently effective rates, the adopted rates will look as follows:

Class of Service	Current Rates (1-1-82) (¢/th)	Adopted Rates (¢/th)	% Increase
Residential			
Tier I	28.297	33.928*	
Tier II	38.177	51.691	
Tier III	56.721	62.616	
Average Resid. Rate	38.2	45.5	
Commercial-Industrial			
GN-1	38.177	51.691	
GN-2	38.177	52.616	
G-COG	45.767	51.808	
GN 32/42	44.654	52.616	
GN 36/46	41.767	52.616	
Scattergood	45.767	51.808	
GN-5	45.767	51.808	
NH_3	35.319	42.582	
Average Retail Rate	41.5	49.8	
Wholesale			
Long Beach	32.431	39.455	
San Diego	32.431	39.455	
System Average	40.7	48.8	19.9%
Below System Average			
Lifeline (including 6.6¢/th customer charge)	14.0%	17.0%	
Residential	6.1%	6.7%	

* Customer charge of about 6.6¢/th not included.

Contrary to the assertions of certain parties, Cavagnaro's guidelines are fairly easy to apply. The adopted rate design guidelines are applied to the total authorized revenue requirement, excluding the conservation cost adjustment (CCA) and GEDA components. The midpoint of the recommended lifeline rate discount of 20% of the average system rate is used to set that rate. The Ammonia Producers rates and wholesale customer rates are established according to formula. The marginal rate is then derived mathematically by dividing the remaining revenue requirement by the remaining system sales. In the instant case, a marginal rate in the range of 51.7¢/th to 52.6¢/th is produced.

The validity of the marginal rate is tested by considering:

1. Other proposed measures of a reasonable price for discretionary purchases, such as the cost of imported crude supplies adjusted to reflect contractual obligations of electric utilities;
2. The variable cost of the most expensive gas supply; and
3. The price of 0.25% and 0.5% low sulfur fuel oils and the price of #2 distillate oil.

In subsequent proceedings, the completion of economic studies by steam electric generation customers and fuel switching studies by SoCal will provide additional means for testing and validating the marginal rate. They will also obviate the need to derive the initial marginal rate by a mathematical calculation.

To the extent that some exercise of judgment is required to arrive at a reasonable range for the marginal rate, that is an inevitable and unavoidable aspect of ratesetting. As yet, no one has developed a process for designing rates which all parties agree is workable and completely objective. The exercise of judgment in determining just and reasonable rates is our ultimate responsibility. We will exercise that judgment by establishing a marginal ~~rate annually during~~ SoCal's reasonableness review.

After the marginal rate is derived and tested, the GEDA and CCA components are included within the appropriate rate schedules.

Consistent with D.82-02-135, the CCA does not apply to wholesale rates, Ammonia Producers rates, and sales for steam electric generation.

The resulting rate to GN-5 customers is 51.808¢/th, the lowest commercial-industrial retail rate. This rate is slightly less than the rate of 52¢/th proposed by SoCal as representative of alternative fuel costs for 0.25% sulfur fuel oil customers. The rate for the other low priority customers of 52.616¢/th remains near the lower end of the range of costs for 0.5% sulfur #6 alternate fuel oil. For February 1982 SoCal estimated a range of costs of 51¢/th to 56¢/th for such alternate fuel. Staff presented an estimate of the low range of costs for 0.5% sulfur #6 fuel oil from 51.35¢/th to 51.85¢/th. The rates produced by the guidelines are just and reasonable, and we will adopt them.

We are not unmindful that today's adopted rates might produce some fuel switching, especially in view of the testimony by DWP. The record evidence prompts doubts that there will be significant switching on the order of 20%; more massive fuel switching seems highly improbable. Furthermore, the air pollution control requirements will have an as yet undefined impact upon any fuel switching that could potentially occur. We will monitor developments very closely. We will also expectantly await SoCal's study on fuel switching. We will also expect SoCal to seriously analyze means of preventing massive fuel switching suggested in staff counsel's brief, with particular attention paid to the possibility of a tariff alternative whereby its P-3 and P-4 customers might willingly pay a premium for a virtually firm gas supply.

C. Economic Test for New Long-Term Gas Supply Projects

1. SoCal's Test

As its test for new long-term gas supply projects, SoCal recommends a standard that compares the net cost of the new gas supply increment with the net cost of the alternate fuels or energy displaced by the gas over the life of the proposed project. If the net cost of the new supply is less than the net cost of the displaced alternate fuels or energy over the project's life, purchase of the new long-term gas supply volumes would be considered a prudent purchase.

In applying this economic test, determination of which alternate fuel cost to measure against the potential gas costs depends on which customer class would experience reduced curtailment as a result of the new supply project. If curtailment to P-1 customers would be avoided or reduced, the cost of the new gas supply would be compared to the cost of electricity. If only P-5 customers were to experience reduced curtailment over the life of the project, the cost of the new gas supply would be compared to the cost of .25% sulfur fuel oil delivered to the steam plant.

If the Commission decides to adopt a test at this time to determine the prudence of new, long-term gas supply projects, SoCal urges the Commission to adopt a test that would not prejudge one of the central issues of a future certificate proceeding -- the issue of cost justification. SoCal firmly believes that the appropriate test is to compare the cost of the new supply project with the cost of whatever energy forms the evidence in the certificate proceeding might show would be displaced over the life of the project.

In addition to a strictly economic analysis, SoCal maintains that any test for determining the prudence of new, long-term supply projects should take into account the substantial nonmonetary benefits of burning gas over oil. Just as the Commission should not prejudge what the evidence on cost justification might show in a future certificate proceeding, it should not prejudge what the evidence might show regarding the nonmonetary benefits of a new long-term gas supply project. If evidence regarding such factors as air quality, balance of payments, or security of supply were to show substantial nonmonetary benefits to a new supply project, the Commission may well determine that those factors tip the balance in favor of authorizing the project, even if its cost were to exceed the cost of alternate energy forms displaced over the project life. To foreclose the possibility of such a determination in a future certificate proceeding because of an overly restrictive test formulated in this proceeding would be most unwise.

2. Staff's Test

Under the staff's economic test, the full cost of a new gas supply project would be compared with the cost of imported crude oil displaced over the life of the proposed project. If the net cost of such a new supply at the California border exceeds the cost of imported crude delivered to California refiners over the life of the gas supply project, acquisition of the gas supply would be imprudent.

Staff uses the price of crude oil as a reference or comparison price because it is an easily identifiable price. By contrast, the price of refinery products, i.e., the alternative fuels which are crucial components of SoCal's economic test reference price, are essentially subject to negotiation depending upon the unique market conditions for the refiners and their customers at a particular point in time and, therefore, the refined product price may only reflect an idiosyncratic perception of value by certain refinery customers. It could also include underlying fixed costs that should not be taken into account when measuring the avoided cost of burning gas instead of fuel oil.

Staff acknowledges that when natural gas is consumed rather than fuel oil it displaces not only crude oil but also the additional resources required to transform crude oil into fuel oil. Staff contends its test compensates for such costs since it compares the cost of gas at the California border--rather than as delivered to the burner tip--to the cost of crude as delivered to the refineries.

In other words, staff assumes for purposes of the test that the refiner's margin and the cost of delivering the gas from the border to the burner tip are about the same.

Staff presents its economic test as the only proposal with any meaningful use. Use of a test that would allow SoCal to build the price of electricity into its economic analysis makes no sense; it would simply sanction a policy of "gas at any cost." Since SoCal does its supply planning on a worst case basis, every new supply project will be viewed as necessary to protect P-1 and P-2 customers from curtailment under some pessimistic scenario. Once the P-1 and P-2 customers' needs are plugged into SoCal's economic test, out comes a blank check to purchase gas at any cost to meet supply requirements under worst case forecasts.

SoCal, in its brief, states that essentially there is no significant distinction between its proposed test and the staff recommendation. Staff accepts this statement as a waiver by SoCal of any objection to adoption of the staff's economic test.

3. Discussion

Our adoption of an economic test for new long-term gas supply projects should not be construed as a prejudgment of economic issues to be raised in future supply project certification proceedings. Consistent with its constitutional responsibilities and its own practices and procedures, the Commission will make a de novo review of an application for certification of a new gas supply project under the circumstances existing at the time of the filing. It is a practical, if not legal, maxim that we cannot bind the actions of a future Commission.

Nor are we attempting the impossible task of devising a single economic test which will universally encompass all of the economic factors which should be considered in determining the prudency of a future gas supply project. Rather, our adoption of the staff's test, which is the most reasonable alternative based upon review of the record evidence, should serve as a useful planning tool for SoCal.

The economic test is intended as a signal to SoCal and perhaps indirectly to SoCal's suppliers that "gas at any cost" is not an acceptable gas acquisition policy in California. It is our signal that we expect SoCal to demonstrate that it has made a rigorous economic analysis long before it comes before this Commission requesting certification of a new gas supply project. SoCal will be expected to employ the economic test in planning future supply acquisitions, in negotiating with its domestic and foreign suppliers, and in requesting certifications of new supply projects before FERC.

Of course, we cannot bind the actions of SoCal in planning, negotiating, and applying to FERC for acquisition of new gas supplies. However, this Commission can state that in any future proceedings in which SoCal asks approval of costs associated with new long-term gas supply projects, SoCal will be expected to demonstrate that it considered the adopted economic test in the planning, negotiating, and certificating phases of acquiring the new gas supply. Failure to so demonstrate will create a presumption that the new gas supply purchases are imprudent.

D. Economic Test for Short-Term Discretionary Gas Purchases

1. SoCal's Recommendation

SoCal proposes adoption of an economic test to apply to the purchase of discretionary volumes of gas under existing supply contracts. As a test for the current forecast period, SoCal recommends that a comparison be made between the variable cost of the discretionary gas purchased and the landed cost of Indonesian crude oil. Only variable costs should be considered since the fixed costs associated with the gas supply are already incurred, irrespective of whether the discretionary gas purchased is not. By application of SoCal's test, discretionary purchases would be prudent if their cost was lower than the landed cost of Indonesian crude oil.

SoCal recommends use of the landed cost of Indonesian crude oil as the reference or comparison point for the following reason: During the period October 1981 through March 1982, purchases of the relevant discretionary gas supply, i.e. Pan-Alberta volumes above the annual take-and-pay cap,5/ would reduce curtailment to P-5 customers under average temperature conditions. Reduced curtailment to P-5 customers would displace Indonesian crude oil, the feedstock for the 0.25% sulfur fuel oil burned by P-5 customers.

SoCal maintains that the only significant point of disagreement between its test and the staff proposal is whether the cost of underlift charges or other economic penalties incurred by

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5/ SoCal notes that its April 1982 CAM filing does not forecast any purchases at 56.7¢/th of Pan-Alberta supplies above the annual take-and-pay cap during the period April 1982 through March 1983. SoCal's next discretionary supply is PG&E best efforts gas, estimated to cost 47.555¢/th during the period.

However, during the forecast period, SoCal estimates it will pay $527,916,110 for contractually obligated takes of Pan-Alberta gas at 75.352¢/th, including variable and fixed costs. We strongly urge SoCal to explore every avenue for renegotiating either or both the volume and price of the Pan-Alberta purchases.

SoCal's P-5 customers as a result of taking gas should be deducted from the cost of Indonesian crude oil in comparing it with the variable cost of the discretionary gas supply. SoCal argues that such penalty costs should not be considered for two reasons: First, these costs are outweighed by the offsetting benefits of burning gas, such as improved air quality and balance of payments. Secondly, and perhaps more importantly, it is extremely difficult for SoCal to determine in advance what the penalty costs might be or even whether they might be incurred. No one, even Edison itself, can determine on a day-to-day basis what the cost of economic penalties might be. Yet SoCal must decide on a day-to-day basis whether to purchase discretionary gas supplies. A gas distribution system simply cannot be operated any other way. There are too many variables relating to availability of supply, fluctuations in demand, operational needs of underground storage, and constant weather changes, for firm decisions regarding discretionary gas purchases to be made on any other than a daily basis. Although future discretionary gas purchases are estimated on an average monthly or yearly basis, the only wholly dependable feature of such estimates is that they are never completely accurate.

Since it is so difficult to quantify both the benefits of burning gas and the costs of oil penalties and because the two would likely offset each other anyway, SoCal recommends that the landed cost of Indonesian crude oil be accepted as the test criterion, at least on a trial basis. In this proceeding, that cost was shown to be $6.65 per MMBtu's in November 1981.

2. Staff's Recommendation

The staff-recommended economic test for the purchase of discretionary supply would compare the net cost of the discretionary supply at the California border to the cost of imported crude delivered to California refiners. The net cost of the gas supply at the California border is defined as the border price plus the cost of any economic penalties that may result from the electric utilities' obligation to purchase certain quantities of fuel oil under long-term contracts. Under this test, if the supply with the added cost of any economic penalties exceeded crude prices it would be imprudent to purchase the discretionary gas.

The application of staff's test is fairly straightforward. The FOB price of Indonesian crude would be taken from any accepted source, such as the weekly published numbers from the Department of Energy; \$2.50 is then added to cover shipping, handling, and import fees (unless this increases), and the resulting reference price is used for the test. The purchase of any discretionary gas at less than this price at the California border would be prudent unless economic penalties in electric utility fuel oil contract result. If the effect of purchasing the discretionary gas displaces oil and results in an increase in electric utility fuel oil storage costs, losses on resale of oil, or the payment of underlift charges, these additional costs must be subtracted from the benefits realized by backing-out the imported oil. If its test is to be workable, staff acknowledges that the gas and electric utilities will have to provide each other with the cost information necessary to make this calculation.

Based on the current reference price developed for Indonesian crude and estimated underlift penalties for Edison at \$6 per barrel, staff concluded from its test that it would be unreasonable for SoCal to make any purchases of Pan-Alberta discretionary gas during the forecast period, April 1982 through March 1983.

Staff counsel, while offering the staff test as reasonable and workable, takes strong exception to SoCal's version of the discretionary supply test. Staff sees SoCal's test as consisting of two components. The first component holds that if the variable cost of the discretionary purchase is below the landed cost of Indonesian crude oil established by the Commission for the current forecast period, then the purchase would be deemed reasonable per se, as long as the purchase of discretionary volumes does not require the turn back of cheaper gas supplies. The second component holds that if the cost of a discretionary purchase were above the landed cost of Indonesian crude oil as established by SoCal, then SoCal can attempt to show that nonmonetary factors and other circumstances make the purchase reasonable.

The first part of SoCal's test is the same as staff's recommendation except it significantly fails to include the added cost of fuel contract penalties or increased storage. The second level of SoCal's discretionary test is simply pointless; it merely serves to provide another blank check for SoCal to purchase additional supply since, according to SoCal, the so-called nonmonetary factors may be worth from $10 to $40 a barrel. Even if we were able to quantify all of the benefits of burning gas over oil, these externalities, such as improved air quality and balance of payments do not properly belong to an economic test for discretionary supply unless one is willing to assign the full economic burden of these benefits to SoCal gas customers alone. Moreover, staff points out that the economics of air quality considerations are already built into the test by using the low sulfur Indonesian crude as the reference price instead of domestic crude.

An additional point of controversy regarding the test for discretionary purchases concerns the meaning of "discretionary purchase." Under its Pan-Alberta contract, SoCal is obligated to take minimum daily volumes as well as a minimum annual volume of Pan-Alberta gas. The contract obligates SoCal to take about 40% of the contract quantity on any given day while it requires purchase of about 70% of contract volumes over the course of the year.

SoCal takes the position that none of the Pan-Alberta purchases can be considered discretionary until that point in the contract year is reached where total contract year purchases to date, plus the minimum daily purchase obligation multiplied by the number of days left in the contract year, is equal to the contract year obligation. In other words, no purchase should be considered discretionary until the point in the contract year is reached where minimum daily takes for the balance of the year would meet the annual obligation. Staff agrees with this view as a general supply strategy but it is concerned that if SoCal takes more than the daily minimum required during this period it may have to refuse cheaper El Paso and Transwestern supplies because of capacity constraints; and this would be imprudent on SoCal's part. Thus, in staff's view the important consideration is not simply meeting the annual contract minimum take volumes but in minimizing the annual cost of gas for the company. And while it may be generally true that it is better to take large volumes of Pan-Alberta supply in the colder portion of the year when demand is high, this may not be true under all circumstances. In other words, staff is saying that both the minimum daily and the annual minimum volumes must be considered in light of all the circumstances when making judgments about discretionary purchases.

3. TURN's Recommendation

TURN believes that the staff's proposed test is quite correct conceptually, but it faces serious and difficult problems of application.

For the necessary data regarding the electric utilities oil displacement costs, staff suggests that SoCal communicate with its P-5 customers to receive the required information. While the electric utilities are clearly the only reliable source of such data, TURN is very troubled about the practicality of this approach.

In all likelihood, SoCal will be called upon in future proceedings to justify the reasonableness of any high-cost discretionary gas purchases. Often that judgment will turn on whether the incremental gas supply caused underlifts, oil sales losses, or additional inventory costs for the electric utilities. The issue before the Commission, however, will not be whether such costs resulted, but rather whether SoCal knew or should have known that the electric utilities would incur these costs. It takes little imagination to foresee an endless parade of "who told who what and when" questions resulting under this scenario.

An additional layer of complication is added when one considers the fact that one electric utility may be experiencing oil contract penalties at a time when the others are not. Assuming SDG&E were, as a result of additional discretionary supplies, forced to underlift or sell oil at a loss while Edison retained contractual flexibility to reduce its purchases without penalty, staff's economic test would give conflicting signals to SoCal regarding the prudency of purchasing the discretionary supplies.

SoCal may very well argue that these difficulties support its idea that oil displacement costs should be left out of the economic test. This is no answer, because the costs involved are real ones for the ratepayers of southern California. They must be included if the analysis is to produce a reasonable and efficient result.

TURN believes that there is a rational, efficient and equitable solution to this dilemma -- let the electric utilities decide for themselves whether Pan-Alberta or other discretionary gas is preferable to fuel oil. This can only occur in one way -- by pricing the discretionary supplies incrementally (at variable cost) and offering them to the customers who would otherwise be curtailed.

TURN contends that if full marginal cost pricing were to prevail in the gas industry, the resource allocation problems confronting the Commission would not arise. Since natural gas is still partially regulated, however, the revenue requirement (fortunately) remains below what full-marginal pricing would collect. Any gas supply that has a variable cost greater than the marginal rate charged to customers will create a danger of resource misallocation. It appears that only Pan-Alberta gas will fall into this category. Thus, to the extent that those purchases are discretionary, they must be afforded a rate treatment that is separate from the overall rate structure.

Specifically, TURN proposes the following solution: Rates should be set under the adopted rate design guidelines to recover all revenue requirements except the variable cost of any discretionary supply that is more expensive than the marginal rate. On days when that discretionary gas is available SoCal should offer it at variable cost to whatever customers would otherwise experience curtailment - P-5 at least for this forecast period. If the gas is economic in comparison with oil, customers will buy it; if it is not, they won't. No second-guessing, forecasting, or regulatory oversight would be required. Resources would be allocated efficiently because the least-cost fuel will be utilized at the margin. Air quality would be monitored and regulated by the appropriate regulatory bodies, as it should be. SoCal would be freed from the necessity of undergoing an intense reasonableness review of each discretionary purchase.

TURN can see no reason why the application of this approach would pose any special operational problems for SoCal. SoCal's dispatchers maintain daily contact with the P-5 customers.

The offer of discretionary gas would simply add one more point to these discussions; monthly determinations would be even simpler to administer. If on some days P-4 customers were facing curtailment, they would also be contacted by SoCal and could be offered a discretionary supply increment.

It must be emphasized that TURN proposes this approach as a method of resource allocation, not as a means of deriving additional revenue from P-5. Indeed, the Commission could, on a forecast basis, set the marginal rate for P-5 somewhat lower than it would otherwise be, such that the same total revenue would be collected from that class when regular and discretionary purchases are combined. The same could not be done on a recorded basis, because then there would be no net cost or saving to the customer as a result of the discretionary purchase decision.

It is also worth noting that the supplies involved in this proposal are not a very significant proportion of total P-5 deliveries. Maximum discretionary Pan-Alberta volumes are about 225 million therms. This represents only about 8.5% of the estimated P-5 sales. TURN sees its proposal as workable, efficient, uncomplicated, fair, and reasonable, and urges its adoption in lieu of the far more complex, imperfect, and potentially controversial proposals set forth by staff and SoCal.

4. Discussion

Before addressing the appropriate economic test for discretionary gas purchases, it is necessary to indicate our purpose in adopting such a test. Certainly, our primary concern is efficient resource allocation, and our ultimate goal is to achieve the least-cost total fuel mix for Southern California. However, this cannot be realized by merely singling out SoCal and imposing upon it a rigid formula for determining the prudency of discretionary gas purchases. Rather, accomplishment of the goal of efficient energy resource allocation will require both a comprehensive and consistent pattern of regulation and aggressive, effective management by all the southern California energy utilities. We believe our adoption of rate design guidelines based upon marginal cost pricing theory is one step toward the development of a comprehensive regulatory approach. Our adoption of an economic test for SoCal's discretionary purchases will move us even closer toward that end.

The test we adopt today is not intended to serve as a formulaic device by which SoCal, the Commission, or any interested party can unequivocally determine on any given day whether specific discretionary purchases are prudent or not. Reasonableness of utility actions will still be determined on a case-by-case basis during annual reviews. However, as we note in a companion case issued today, guidelines, such as those provided by an economic test for discretionary gas purchases, are nevertheless useful. Properly designed, they sharpen the focus on the burden of proof issue. If purchases meet the economic test this will create a rebuttable presumption that the purchases are reasonable. Purchases that do not meet the guideline are presumptively unreasonable. The applicant will be required to make a strong showing to overcome this presumption.

We also acknowledge that it is all but impossible to devise one economic test which will universally encompass all of the factors which should be considered in determining the prudency of future discretionary gas purchases. For example, the realities of supply and demand must be recognized. Under certain supply scenarios, discretionary gas might be required to serve P-1 through P-4 customers. The assumed weather conditions - warm, cold, wet, dry - during the period in which the discretionary supplies are purchased - must also be considered along with the utility's gas storage policies and operations. Once again such factors could militate in favor of purchasing discretionary supply in order to ensure service to P-1 through P-4 customers.

Furthermore, the prudency of any particular discretionary purchase may well depend upon the perspective from which analysis of the purchase decision is made. From the perspective of the average gas utility customer, irrespective of his classification, prudent policy could well dictate that no purchases of discretionary gas should be made in excess of the price at which it could be sold. Except for the availability of balancing account treatment, this might be the perspective of SoCal as well. From the perspective of the electric utility, it might be prudent for SoCal to acquire discretionary supply as long as the electric utility realized a net economic benefit by burning the purchased gas in lieu of fuel oil. It can also be argued that purchase of discretionary supply is reasonable if it displaces oil and results in a net economic benefit to the regional economy. These are but a few of the perspectives we might consider in developing an appropriate economic test.

Review of the economic tests recommended for our consideration reveals the imperfection of each. All suffer from some conceptual and/or practical difficulty. SoCal's test, based upon the landed cost of Indonesian crude as a reference or comparison price, fails to consider the very real costs of fuel contract penalties potentially incurred by electric utilities who accept the proffered discretionary gas rather than burn fuel oil. By ignoring oil displacement costs, SoCal's test would allow high-cost gas to be purchased even though that gas costs more than the avoidable cost of alternate fuel. Vague assertions that there are nonmonetary benefits associated with burning gas are insufficient to cure the deficiency in the proposed test. Further, it can be said that the landed cost of Indonesian crude oil does not reflect current oil costs since it is a relatively stable price while the low-sulfur oil market can be swinging significantly in either direction.

With respect to the staff test, both TURN and SoCal raise reasonable concerns over the practicality of the approach. The information upon which SoCal must necessarily act in making daily purchase decisions, i.e. oil inventory levels, underlift provisions, prices of oil under contract, etc., are not within its control. SoCal must rely on the timely and forthright provision of the relevant information by the electric utilities. As was previously noted, even the electric utilities themselves may be unable to acquire the necessary information on a timely basis.

TURN proposes a practical solution to the conceptual and administrative difficulties inherent in the recommended economic tests. TURN suggests that SoCal, on days when discretionary gas is available, should offer it at variable cost to any customer who would otherwise experience curtailment. The proposal has certain merit in that it leaves to the purchasers the economic decision whether or not to buy the gas and allocate some of the cost of high priced gas supply to the actual purchasers. On the other hand, day-to-day sale and purchase decisions among SoCal and a variety of potential customers may prove even more impractical than any of the suggested tests. However, the proposal deserves fuller consideration and analysis in SoCal's next CAM proceeding, and we will direct SoCal to submit in its next CAM proceeding an alternative proposal for allowing variable pricing of discretionary gas supply.

While we investigate such possibilities as tariff proposals and TURN's recommendation in subsequent proceedings, we will adopt an economic test for discretionary purchases which will apply in the absence of further action. We have previously adopted a marginal rate ranging from 51.7¢/th to 52.6¢/th for purposes of designing rates.

While it is by no means perfect, such a range provides an adequate benchmark for making a threshold determination of whether a certain discretionary supply purchase is prudent or not.

As was previously noted, development of the marginal rate considers a reasonable price for discretionary purchases, the variable cost of the most expensive gas supply, and the price of alternate fuels, such as 0.25% and 0.5% low sulfur fuel oil and #2 distillate oil. All these elements are relevant to an economic test for discretionary purchases. Also, when economic studies by the steam electric generators and SoCal's fuel switching studies are presented, we intend to further refine the method for determining the marginal rate so that it will represent an even more valid approximation of marginal cost.

In the interim, the marginal rate of 51.7¢/th to 52.6¢/th will provide a clear and useful guideline for discretionary purchases. Purchases of discretionary gas supplies at or below the marginal rate will be presumed reasonable. Purchases of discretionary gas supplies in excess of that rate may be deemed reasonable only upon a strong showing. We note that adoption of the staff's recommended economic test would produce a benchmark or comparison price which is similar to our adopted guideline. Under both tests, purchases of Pan-Alberta supplies at 56.7¢/th would be presumed unreasonable. We are aware that SoCal projects no purchases of 56.7¢/th discretionary Pan-Alberta supplies during the forecast period, April 1982 through March 1983. SoCal's next highest estimated discretionary supply source is PG&E's best efforts gas priced at 47.555¢/th, well under the comparison price of 51.7¢/th-52.6¢/th established by our guideline.

As we have previously stressed, satisfying the economic test only serves to create a rebuttable presumption of prudence. In subsequent proceedings, the burden of proof remains on SoCal to demonstrate the reasonableness of its gas purchase policies. As stated previously, SoCal will be required to make a strong showing to justify purchases which do not meet the economic test. At a minimum, relevant evidence would include the following: (1) supply constraints and demand characteristics; (2) weather-related variables; (3) storage operation; (4) net economic benefits realized by electric utility or other low priority customers; (5) net economic benefits realized by the regional economy; and (6) revision of the "marginal rate" benchmark to reflect actual conditions, including alternate fuel prices, existing at the time the decisions were made to purchase discretionary gas. The latter is necessary since the adopted marginal rate will not necessarily always adequately reflect relevant factors occurring during the forecast period.

With respect to the issue of what constitutes a "discretionary purchase", we find the strategy employed by PG&E useful. For SoCal, only the required daily take would be considered the minimum contractual obligation in September, with amounts above that treated as discretionary and subject to the economic test. Summer minimum takes would reflect minimum daily requirements, with winter purchases increased to meet the annual obligation (absent capacity constraints). Amounts in excess of these targets would be considered discretionary, regardless of the month involved. This approach is reasonable and will be used for purposes of defining "discretionary purchases."

Finally, the California Gas Producers Association (CGPA) raises an issue which requires our resolution. During the forecast period, SoCal projects the availability of certain discretionary gas supplies--PG&E best efforts gas at 47.555¢/th and Mich-Con gas at 47.154¢/th. According to SoCal's gas purchase policy discretionary supplies are taken in order of ascending price; the lowest price discretionary supply is taken first. In the instant case, SoCal's policy would dictate the purchase of Mich-Con, given the projected costs, before purchase of PG&E best efforts gas.

CGPA asks that SoCal be directed to purchase additional supplies of gas from PG&E prior to the time that they purchase gas from Mich-Con. CGPA maintains that even though the prices are closely in line, there is a very substantial additional benefit to the ratepayers for natural gas in California by the purchase of additional gas from PG&E. This advantage arises because the PG&E additional gas supplies are generally based upon California gas production in an additional amount. That California gas available at $3.15 is resold by PG&E at around $4.70. Therefore, there is a $1.50 per million Btu's additional value in making those purchases on that basis. Since that is vastly greater than the differential between the Mich-Con gas of 5¢ per million Btu's against $1.50, there is a public interest in requesting, at least for the time being, that SoCal purchase additional supplies of PG&E gas before it turns to out-of-state supplies of Mich-Con gas.

For the reasons stated by CGPA, we will direct SoCal to purchase PG&E best efforts gas before Mich-Con gas as long as the cost differential is less than .5¢/th.

III. SDG&E's A.60901 and A.82-03-38

A. Revenue Requirement

SDG&E's consolidated applications request authority to increase its natural gas rates, in conformance with the provisions of its CAM tariff, to offset the increase in the cost of natural gas proposed by its supplier, SoCal, in A.60867 and A.82-03-16. In addition, SDG&E seeks an adjustment to its CAM rates in order to reflect the recorded under- and overcollections in its supply adjustment mechanism (SAM) and PGA subaccounts, respectively.

Once the commodity rate for sales by SoCal to SDG&E under the G-61 Schedule is adopted, SDG&E's requested revenue requirement in its consolidated applications is relatively easy to determine. As previously noted, the adopted wholesale rate for SDG&E is 39.455¢/th. SDG&E's total revenue requirement is then derived, using the staff methodology, as follows:

APRIL 1982 CAM
REVENUE REQUIREMENT*

		Amount (Thousands of Dollars)
1.	PGA Revenue Requirement	
A.	Capacity Charge	$ 13,550.0
B.	Commodity Charge (941,222 x $0.39455)	371,359.1
C.	LNG Net	-969.0
D.	Purchases	383,940.1
E.	Twice PGA Bal. Acct. 2/28/82	-8,660.5
F.	Subtotal	$ 375,279.6
G.	F&U on Retail Sales @ 2.0676%	3,918.1
H.	PGA Requirement	$ 379,197.7
2.	SAM Revenue Requirement	
A.	Base Cost Amount	$ 92,644.3
B.	Twice SAM Bal. Acct. 2/28/82	5,687.5
C.	Subtotal	$ 98,331.8
D.	Less SDFFD	294.2
E.	SAM Requirement	$ 98,037.6
3.	Revenue Requirement	$ 477,235.3
4.	Revenue at Present Rates	$ 410,962.9
5.	Increase	$ 66,272.4

*Excludes all revenues associated with the San Diego Franchise Fee Differential (SDFFD) and the conservation surcharge (CPAC).

SDG&E's gas department revenue requirement is $477,235,300. Under rates currently in effect, SDG&E is collecting $410,962,900 in annual revenues. The increased annual revenue requirement necessary to offset the increase in the cost of natural gas supplied by SoCal and to reflect six-month amortization of the recorded under- and over-collections in SDG&E's respective SAM and PGA subaccounts is $66,272,400. The amount of the increased annual revenue requirement is reasonable and it will be adopted.

B. Rate Design

SDG&E proposed a rate design in conformance with Commission's policy on gas rate design as stated in D.93629, issued October 20, 1981 in SDG&E's A.60901. The following criteria were used:

(1) No increases were made to the customer charges. Increases were made only in the commodity rates;

(2) The lifeline rate was set at approximately 85 percent of the average system rate, the average system rate is the total revenue requirement divided by the total sales;

(3) Schedules GN-36 and GN-46 rates were set close to the estimated current price of #6 low sulfur fuel oil;

(4) Schedules GN-3 and GN-4 rates were set to approximate the estimated current price of #2 fuel oil (or at a premium above the Schedules GN-36 and GN-46 rates). A premium of 3¢/therm was the controlling guideline utilized for Schedules GN-3 and GN-4;

(5) The Schedule GN-5 rate was increased to approximate the price of #6 fuel oil;

(6) The residential blocks were inverted with the last block having the highest rates; and

(7) Schedules GN-1 and GN-2 rates were set relatively near to the modified average system rate (less lifeline sales and revenues) and designed to recover the remaining revenue requirements.

When these guidelines are applied to SDG&E's total adopted revenue requirement of $477,235,300, which translates into a revenue increase of $66,272,400, the rates proposed by SDG&E would look as follows:

Class of Service & Schedule	CAM Rates SAM Rate	PGA Rate	CPAC Rate	Proposed Rates	Present 1-1-82 Rates	Increase
	(Cents per therm)					
RESIDENTIAL						
Schedules GR, GM, GS & GT						
Customer Charge, per month	$1.70			$1.70	$1.70	-
Tier I, per therm (GR, GM)	02.277	41.323	00.20	43.8	36.6	07.2
Tier I, per therm (GS)	(02.123)	41.323	00.20	39.4	32.9	06.5
Tier I, per therm (GT)	(04.323)	41.323	00.20	37.2	31.1	06.1
Tier II, per therm	17.077	41.323	00.20	58.6	51.4	07.2
Tier III, per therm	35.977	41.323	00.20	77.5	70.3	07.2
OTHER RETAIL						
Schedule GN-1						
Customer Charge, per mo.	$1.70			$1.70	$1.70	-
All usage, per therm	17.077	41.323	00.20	58.6	51.4	07.2
Schedule GN-2						
All usage, per therm	17.077	41.323	00.20	58.6	51.4	07.2
Schedule GN-3						
All usage, per therm	17.277	41.323		58.6	51.4	07.2
Schedule GN-36						
All usage, per therm	14.277	41.323	-	55.6	48.4	07.2
Schedule GN-4						
All usage, per therm	17.277	41.323		58.6	51.4	07.2
Schedule GN-46						
All usage, per therm	14.277	41.323	-	55.6	48.4	07.2
Special Contract 176						
Per Lamp per month	$4.92	$7.67	04.00	$12.63	$11.29	$1.34
Special Contract 186						
All usage, per therm	17.077	41.323	00.20	58.6	51.4	07.2
INTERDEPARTMENTAL						
Schedule GN-5						
All usage, per therm	09.214	40.486	-	49.7	42.5	07.2

Staff proposes that SDG&E's rates be designed according to the following guidelines:

(1) The residential Tier I (lifeline) rate is set at 80% of the system average rate (SAR);

(2) The Tier II, and the GN-1 through -4 rates are set at the modified SAR which excludes lifeline sales and revenues;

(3) The Tier III rate is set so as to retain the current price differential with Tier II;

(4) The GN-5 rate is set at the estimated price of #6 low sulfur fuel oil (LSFO);

(5) The system average percentage increase of 16.1% is given to the revenue for Special Contract 176. The revenue from the guideline rates undercollected the requirement by $4,359,300. The commodity rates were then increased, uniformly, by .471¢/th to eliminate the undercollection.

Staff's proposed rate guidelines, when applied to the adopted revenue requirement and a slightly lower sales figure recommended by staff, produce the following rates:

Proposed Rates*
(¢/th)

Classification	Guideline Rate	Adjustment	Proposed Rate
Residential**			
Tier I	41.271	.471	41.742
Tier II	55.478	.471	55.949
Tier III	74.378	.471	74.849
Commercial-Industrial			
GN-1/-2	55.478	.471	55.949
GN-3/-4	55.478	.471	55.949
GN-5	51.35	.471	51.821

*Excludes CPAC rates of about .2¢/th in the residential GN-1 and GN-2 rate.

**Residential sales are reduced by 2,389.0 Mth to compensate for discounts on Schedules GS, GT, and G-90.

Even though the GN-5 rate of 51.821¢/th is higher than the #6 LSFO price, staff maintains that this should present no problem. The 51.35¢ shown for #6 LSFO is only a reference. SDG&E purchases #6 LSFO on a long-term contract and the last reported price was 70.66¢/therm equivalent. Gas priced up to 80% of the contract price (56.53¢) should leave SDG&E an adequate margin to pay the costs associated with using unanticipated supplies of gas, such as underlift charges, and still realize an economic advantage from burning such gas.

Staff also recommends that Schedules GN-36/46 be canceled. These schedules were established to accommodate potential customers with #6 LSFO capability. Since there are no customers available, there is no need for them. Further, staff cannot recommend a rate low enough to be competitive with #6 LSFO.

We will adopt the staff level of proposed sales and the staff-recommended rate design, with two exceptions. The revenue from the guideline rates undercollected the requirement. To eliminate the shortfall, we will uniformly raise the commodity rates, except for lifeline and GN-5 customers. It is appropriate to lower staff's recommended GN-5 from 51.21¢/th to 50.5¢/th. This schedule covers sales from SDG&E's gas department to its electric department. The decrease in the proposed GN-5 rate will mitigate a portion of the ultimate increase borne by SDG&E's electric ratepayers as a result of today's decision. As noted, we will maintain lifeline at 80% of the system average rate. The revenue shortfall resulting from the decrease in the GN-5 rate will be made up by increasing the proposed Tier II, Tier III, and GN-1 through GN-4 rates by 3.86¢/th.

The adopted rates will be as follows:

Classification	Guideline Rate	Adjusted	Adopted Rate*
	¢/th		
Residential			
Tier I	41.271		41.271
Tier II	55.478	3.86	59.338
Tier III	74.378	3.86	78.238
Commercial-Industrial			
GN-1/2	55.478	3.86	59.338
GN-3/4	55.478	3.86	59.338
GN-5	50.5		50.500

*CPAC rate of about .2¢/th has not been included in the applicable residential, GN-1 and GN-2 rates.

We will grant the staff's recommendation to cancel the GN-36/46 schedule for potential customers with #6 LSFO. Since we would establish a GN-36/46 rate equal to the GN-3/4 rate, consistent with the rate design guidelines adopted for SoCal, any distinction between the two schedules becomes academic. There is no need for a GN-36/46 schedule.

One issue involving accounting practices remains for resolution. Staff disagrees with SDG&E's treatment of GS and GT discounts in the PGA rates. SDG&E uses a uniform PGA rate for retail sales and assigns all of the discounts to the SAM rates, which results in negative GS and GT SAM rates. Staff applies the discount to both PGA and SAM rates which results in positive rates in both instances. Staff argues that the discounts should be applied to both SAM and PGA rates for Schedules GS and GT.

SDG&E strongly requests that the Commission reject the staff's proposal regarding the internal rate structure which would discount the PGA, the purchase gas rate to lifeline customers. SDG&E argues that this is a clear fiction. SDG&E receives no discount on purchased gas, and such a discount would add unnecessarily to the administrative burden on keeping the balancing account. We find SDG&E's argument persuasive, and therefore we will reject the staff recommendation.

Findings of Fact

1. By consolidated applications A.60867 and 82-03-16, SoCal requests an increase in revenues of $1.106 billion to offset increases in the cost of gas from its suppliers and to amortize existing undercollections in its CAM account.

2. By consolidated applications A.60901 and 82-03-38, SDG&E requests an increase in revenues of $75 million to offset increases in the cost of gas from its supplier, SoCal, and to amortize existing under- and overcollections in its SAM and PGA subaccounts.

3. The staff's recommended additional revenue requirement for SoCal of $834,294,000 is reasonable and appropriate to offset increased purchased gas costs and to amortize current undercollections.

4. In computing the authorized revenue requirement, it is appropriate to use balancing account information as of March 31, 1982, which reflects a predominance of recorded information.

5. In calculating gas costs, it is inappropriate to reflect in projected costs the effect of FERC increases which will become effective subsequent to the April 1, 1982 CAM revision date.

6. Today's authorized rates contain a large component in excess of current costs which will serve to offset increases in the cost of gas to SoCal that may occur between SoCal's April and October revision dates.

7. Issues pending in A.60339 are resolved in a companion case decided today and therefore their revenue impact is more properly addressed in that decision.

8. Staff's method of calculating gas costs is appropriate.

9. A six-month amortization of the CAM balancing account is in the best interests of SoCal's ratepayers and shareholders alike.

10. It is appropriate to adopt an annual reasonableness review for SoCal's CAM.

11. It is appropriate to develop a uniform rate design policy applicable to all classes.

12. Fully allocated embedded cost of service is not a meaningful measure in setting gas rates, it is inappropriate to mask the signal of the cost of new gas supplies with such costs.

13. The most efficient allocation of gas should occur when the customer pays the marginal or resource cost of gas.

14. Gas customers should pay as close to the utility's marginal supply costs as revenue requirement constraints and minimization of fuel switching allow.

15. Pricing the lifeline rate at less than marginal cost is consistent with legislative intent.

16. While they may not produce the maximum conservation, inverted residential rates provide a price signal which induces conservation.

17. The conservation signal given by the adopted rate design guidelines is both adequate and appropriate.

18. The rate design guidelines are equitable, since they essentially provide the same price signal to all classes of customers.

19. The adopted rate design guidelines based upon marginal cost theory produce conservation efficiency and equitable rates.

20. The rate adopted for the Ammonia Producers only exceeds the rates adopted for lifeline and wholesale customers and is consistent with the statutory mandate.

21. The wholesale commodity rate is appropriately developed by using SoCal's coverage cost of gas plus a GEDA and franchise fee factor.

22. It is appropriate to eliminate the $.00215 refund recollection factor contained in the Long Beach wholesale rate.

23. A balancing account for wholesale customers has not been justified by the evidence of record.

24. Any action to discount the cogeneration rate below the reference rate is inconsistent with avoided cost concepts and marginal cost pricing theory.

25. The evidence of record prompts doubt that there will be significant fuel switching as a result of adoption of the rate design guidelines.

26. The marginal rate of 51.7¢/th to 52.6¢/th is within the range of prices estimated for alternate fuels.

27. It is appropriate to adopt an economic test for determining the prudency of acquisition of long-term gas supplies.

28. If the net cost of a new gas supply at the California border exceeds the cost of imported crude delivered to California refiners over the life of the gas supply project, acquisition of that gas supply will create a presumption of imprudency.

29. It is appropriate to adopt an economic test for determining the prudency of discretionary purchases.

30. Purchases of discretionary gas in excess of the marginal rate established by the Commission during SoCal's annual reasonableness reviews will create a presumption that such purchases are imprudent.

31. For SoCal, only the required daily take will be considered the minimum contractual obligation in September, with amounts above that treated as discretionary and subject to the economic test; summer minimum takes will reflect minimum daily requirements, with winter purchases increased to meet the annual obligation (absent capacity constraints). Amounts in excess of these targets will be considered discretionary, regardless of the month involved.

32. Since advantages will accrue to California ratepayers, it is appropriate for SoCal to purchase PG&E best efforts gas before Mich-Con gas as long as the cost differential is less than .5¢/th.

33. An additional revenue requirement for SDG&E of $66,272,800 is reasonable to offset increased purchased gas costs and to amortize current over- and undercollections in six months.

34. Staff's level of proposed sales during the forecast period is reasonable.

35. Staff's recommended rate design, with two exceptions, is reasonable.

36. It is appropriate to maintain the lifeline rate at 80% of the system average rate.

37. It is appropriate to lower the staff-recommended GN-5 rate downward to 50.5¢/th.

38. A GN-5 rate of 50.5¢/th allows SDG&E an adequate margin to pay the costs associated with using unanticipated supplies of gas and still realize an economic advantage from burning such gas.

39. There is no need for a GN-36/46 schedule in SDG&E's service territory.

40. There is no need to alter SDG&E's accounting method for treating the Schedule GS and GT discounts in its PGA and SAM subaccounts.

41. Since today's decision will issue after SoCal's and SDG&E's CAM revision dates, this order should be effective immediately.

<u>Conclusions of Law</u>

1. Increased revenues of $834,294,000 should be authorized for SoCal.

2. Increased revenues of $66,272,800 should be authorized for SDG&E.

3. An economic test for determining the prudency of long-term gas supply acquisitions should be adopted for SoCal.

4. An economic test for determining the prudency of discretionary purchases should be adopted for SoCal.

5. A definition of "discretionary purchases" should be adopted for SoCal.

6. Rate design guidelines based upon marginal cost theory should be adopted for SoCal.

7. An annual CAM reasonableness review should be adopted for SoCal.

8. The increased rates and charges authorized by this decision are justified and reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

O R D E R

IT IS ORDERED that:

1. On or after the effective date of this order, Southern California Gas Company (SoCal) is authorized to file revised tariff schedules reflecting rates attached to this order as Appendix B, to be effective no earlier than May 4, 1982. The revised schedules shall apply only to service rendered on or after their effective date.

2. On or after the effective date of this order, San Diego Gas & Electric Company (SDG&E) is authorized to file revised tariff schedules reflecting rates attached to this order as Appendix C, to be effective no earlier than May 4, 1982. The revised schedules shall apply only to service rendered on or after their effective date.

3. An annual reasonableness review of SoCal's CAM expenses shall be established; as part of its showing, SoCal is directed to provide daily operating records to all parties.

4. The $.00215 refund recollection factor in Long Beach's wholesale commodity rate shall be eliminated.

5. Consistent with this decision, an economic test for determining the prudency of long-term gas supply acquisitions shall be adopted for SoCal.

6. Consistent with this decision, an economic test for determining the prudency of discretionary gas purchases shall be adopted for SoCal.

7. Definition of "discretionary purchases" consistent with this decision shall be adopted.

8. SoCal shall submit in its next CAM proceeding an alternative proposal for allowing variable pricing of discretionary gas supplies.

9. SDG&E's Schedules GN-36/46 shall be canceled.

10. SoCal and SDG&E shall send to all their gas customers a bill insert notice explaining the reasons behind today's gas rate increase. The form and content of the notice will be furnished by the Executive Director. Within 50 days after receipt of the notice from the Executive Director, the notice shall be sent to all gas customers.

This order is effective today.

Dated April 28, 1982, at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

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

Joseph E. Bodovitz, Executive Director

APPENDIX A
Page 1

LIST OF APPEARANCES

Applicant in A.60867 and A.82-03-16: Robert B. Keeler and Robert M. Loch, Attorneys at Law, for Southern California Gas Company.

Applicant in A.60901 and A.82-03-38, and Interested Party in A.60867: William L. Reed, Randall W. Childress, and Jeffrey Lee Guttero, for San Diego Gas & Electric Company.

Protestants: Herman Mulman and Edward R. Novikoff, for Seniors for Political Action; and Ed Duncan for himself.

Interested Parties: John R. Bury, H. R. Barnes, Susan M. Beale, and Susan L. Steinhauser, Attorneys at Law, for Southern California Edison Company; Sylvia Siegel and Michel Peter Florio, Attorney at Law, for TURN; Richard A. Alesso, Deputy City Attorney, for Robert W. Parkin, City Attorney, City of Long Beach; Vernon E. Cullum, Superintendent, Regulatory Affairs & Gas Procurement, for City of Long Beach; Ellison Bloodgood, for himself; Graham & James, by Boris H. Lakusta, David J. Marchant, Thomas J. MacBride, Jr., and Ann C. Pongracz, Attorneys at Law, for California Ammonia Producers; William S. Shaffran, Deputy City Attorney, for John W. Witt, City Attorney, City of San Diego; Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth and James E. Addams, Attorneys at Law, for California Manufacturers Association; Martin E. Whelan, Jr., Inc., by Martin E. Whelan, Jr., Attorney at Law, for Tehachapi-Cummings County Water District; James Dycus, for himself; Harry Phelan, for California Asphalt Pavement Association; Robert B. McLennan, Attorney at Law, for Pacific Gas and Electric Company; Pettit & Martin, by Edward B. Lozowicki, Attorney at Law, for Owens-Corning Fiberglas Corporation; Ed Perez, Deputy City Attorney, for Ira Reiner, City Attorney, City of Los Angeles; Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Allen B. Wagner, Attorney at Law, for The Regents of the University of California; Sharon Gleason and Don Dier, Energy Assessments Program, for Department of General Services, State of California; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for General Motors Corporation, Otis M. Smith, General Counsel, and Julius Jay Hollis, Esq.; and

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Henry F. Lippitt, 2nd, Attorney at Law, for California Gas Producers Association.

Commission Staff: Richard D. Rosenberg, Attorney at Law.

(END OF APPENDIX A)

APPENDIX B

Southern California Gas Company

Adopted Commodity Rates

Classification	Rates (c/th)	GEDA (c/th)	CCA (c/th)	Adopted Rates (c/th)
Residential				
Tier I	31.935	.145	.808	33.928
Tier II	50.738	.145	.808	51.691
Tier III	61.663	.145	.808	62.616
Commercial-Industrial				
GN-1/-2	50.738	.145	.808	51.691
G-COG	51.663	.145	-	51.808
GN 32/42	51.663	.145	.808	52.616
GN 36/46	51.663	.145	.808	52.616
Scattergood	51.663	.145	-	51.808
GN-5	51.663	.145	-	51.808
NH_3	42.582	-	-	42.582
Wholesale				
G-60	39.310	.145	-	39.455
G-61	39.310	.145	-	39.455

(END OF APPENDIX B)

APPENDIX C

San Diego Gas & Electric Company

April 1982 CAM
Statement of Commodity Rates
¢/th

Schedule	CAM Rates	CPAC Rates	Adopted Tariff Rates
Residential			
Tier I, GR, GM	41.271	0.20	41.471
Tier I, GS	37.144	0.20	37.344
Tier I, GT	35.08	0.20	35.28
Tier II, All	59.338	0.20	59.538
Tier III, All	78.238	0.20	78.438
Nonresidential			
GN-1	59.338	0.20	59.538
GN-2	59.338	0.20	59.538
GN-3, -4	59.338	-	59.338
GN-5	50.5	-	50.5
Spec. Cont. 176*	13.03	0.04	13.07
Spec. Cont. 186	59.338	0.20	59.538

* $ per lamp.

(END OF APPENDIX C)

In contrast to the currently effective rates, the adopted rates will look as follows:

Class of Service	Current Rates (1-1-82) (¢/th)	Adopted Rates (¢/th)	% Increase
Residential			
Tier I	28.297	33.928*	
Tier II	38.177	51.691	
Tier III	56.721	62.616	
Average Resid. Rate	38.2	45.5	
Commercial-Industrial			
GN-1	38.177	51.691	
GN-2	38.177	52.616	
G-COG	45.767	51.808	
GN 32/42	44.654	52.616	
GN 36/46	41.767	52.616	
Scattergood	45.767	51.808	
GN-5	45.767	51.808	
NH_3	35.319	42.582	
Average Retail Rate	41.5 91.5	49.8	
Wholesale			
Long Beach	32.431	39.455	
San Diego	32.431	39.455	
System Average	40.7	48.8	19.9%
Below System Average			
Lifeline (including 6.6¢/th customer charge)	14.0%	17.0%	
Residential	6.1%	6.7%	

* Customer charge of about 6.6¢/th not included.

Consistent with D.82-02-135, the CCA does not apply to wholesale rates, Ammonia Producers rates, and sales for steam electric generation.

The resulting rate to GN-5 customers is 51.808¢/th, the lowest commercial-industrial retail rate. This rate is slightly less than the rate of 52¢/th proposed by SoCal as representative of alternative fuel costs for 0.25% sulfur fuel oil customers. The rate for the other low priority customers of 52.616¢/th remains near the lower end of the range of costs for 0.5% sulfur #6 alternate fuel oil. For February 1982 SoCal estimated a range of costs of 51¢/th to 56¢/th for such alternate fuel. Staff presented an estimate of the low range of costs for 0.5% sulfur #6 fuel oil from 51.35¢/th to 51.85¢/th. The rates produced by the guidelines are just and reasonable, and we will adopt them.

We are not unmindful that today's adopted rates might produce some fuel switching, especially in view of the testimony by DWP. The record evidence prompts doubts that there will be significant switching on the order of 20%; more massive fuel switching seems highly SS/ improbable. Furthermore, the ~~Air Resources Board~~ pollution control requirements will have an as yet undefined impact upon any fuel switching that could potentially occur. We will monitor developments very closely. We will also expectantly await SoCal's study on fuel switching. We will also expect SoCal to seriously analyze means of preventing massive fuel switching suggested in staff counsel's brief, with particular attention paid to the possibility of a tariff alternative whereby its P-3 and P-4 customers might willingly pay a premium for a virtually firm gas supply.

C. Economic Test for New Long-Term Gas Supply Projects

1. SoCal's Test

As its test for new long-term gas supply projects, SoCal recommends a standard that compares the net cost of the new gas supply increment with the net cost of the alternate fuels or energy displaced purchases. Rather, accomplishment of the goal of efficient energy resource allocation will require both a comprehensive and consistent pattern of regulation and aggressive, effective management by all the southern California energy utilities. We believe our adoption of rate design guidelines based upon marginal cost pricing theory is one step toward the development of a comprehensive regulatory approach. Our adoption of an economic test for SoCal's discretionary purchases will move us even closer toward that end.

The test we adopt today is not intended to serve as a formulaic device by which SoCal, the Commission, or any interested party can unequivocally determine on any given day whether specific discretionary purchases are prudent or not. Reasonableness of utility actions will still be determined on a case-by-case basis during annual reviews. However, as we note in a companion case issued today, guidelines, such as those provided by an economic test for discretionary gas purchases, are nevertheless useful. Properly designed, they sharpen the focus on the burden of proof issue. If

SS ~~P~~purchases ~~that~~ meet the economic test, this will create a rebuttable presumption that the purchases are reasonable. Purchases that do not meet the guideline ~~may be found reasonable on a sufficient showing by the applicant.~~ are presumptively unreasonable. The applicant will be required to make a strong showing to overcome this presumption.

We also acknowledge that it is all but impossible to devise one economic test which will universally encompass all of the factors which should be considered in determining the prudency of future discretionary gas purchases. For example, the realities of supply and demand must be recognized. Under certain supply scenarios, discretionary gas might be required to serve P-1 through P-4 customers. The assumed weather conditions - warm, cold, wet, dry - during the period in which the discretionary supplies are purchased - must also be considered along with the utility's gas storage policies and operations. Once again such factors could militate in favor of purchasing discretionary supply in order to ensure service to P-1 through P-4 customers.

While it is by no means perfect, such a range provides an adequate benchmark for making a threshold determination of whether a certain discretionary supply purchase is prudent or not.

As was previously noted, development of the marginal rate considers a reasonable price for discretionary purchases, the variable cost of the most expensive gas supply, and the price of alternate fuels, such as 0.25% and 0.5% low sulfur fuel oil and #2 distillate oil. All these elements are relevant to an economic test for discretionary purchases. Also, when economic studies by the steam electric generators and SoCal's fuel switching studies are presented, we intend to further refine the method for determining the marginal rate so that it will represent an even more valid approximation of marginal cost.

In the interim, the marginal rate of 51.7¢/th to 52.6¢/th will provide a clear and useful guideline for discretionary purchases. Purchases of discretionary gas supplies at or below the marginal rate will be presumed reasonable. Purchases of discretionary gas supplies in excess of that rate may be
55 deemed reasonable only upon a ~~sufficient~~ strong showing. We note that adoption of the staff's recommended economic test would produce a benchmark or comparison price which is similar to our adopted guideline. Under both tests, purchases of Pan-Alberta supplies at 56.7¢/th would be presumed unreasonable. We are aware that SoCal projects no purchases of 56.7¢/th discretionary Pan-Alberta supplies during the forecast period, April 1982 through March 1983. SoCal's next highest estimated discretionary supply source is PG&E's best efforts gas priced at 47.555¢/th, well under the comparison price of 51.7¢/th-52.6¢/th established by our guideline.

As we have previously stressed, satisfying the economic test only serves to create a rebuttable presumption of prudence. In subsequent proceedings, the burden of proof remains on SoCal to demonstrate the reasonableness of its gas purchase policies. ~~We will not restrict the type of evidence which SoCal may wish to present in an effort to support a finding of reasonableness. However,~~ At a minimum, relevant evidence would ~~will~~ include the following: (1) supply constraints and demand characteristics; (2) weather-related variables; (3) storage operation; (4) net economic benefits realized by electric utility or other low priority customers; (5) net economic benefits realized by the regional economy; and (6) revision of the "marginal rate" benchmark to reflect actual conditions, including alternate fuel prices, existing at the time the decisions were made to purchase discretionary gas. The latter is necessary since the adopted marginal rate will not necessarily always adequately reflect relevant factors occurring during the forecast period.

With respect to the issue of what constitutes a "discretionary purchase", we find the strategy employed by PG&E useful. For SoCal, only the required daily take would be considered the minimum contractual obligation in September, with amounts above that treated as discretionary and subject to the economic test. Summer minimum takes would reflect minimum daily requirements, with winter purchases increased to meet the annual obligation (absent capacity constraints). Amounts in excess of these targets would be considered discretionary, regardless of the month involved. This approach is reasonable and will be used for purposes of defining "discretionary purchases."

As stated previously, SoCal will be required to make a strong showing to justify purchases which do not meet the economic test.

5. A definition of "discretionary purchases" should be adopted for SoCal.

6. Rate design guidelines based upon marginal cost theory should be adopted for SoCal.

7. An annual CAM reasonableness review should be adopted for SoCal.

8. The increased rates and charges authorized by this decision are justified and reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

ORDER

IT IS ORDERED that:

1. On or after the effective date of this order, Southern California Gas Company (SoCal) is authorized to file revised tariff schedules reflecting rates attached to this order as Appendix B, to be effective no earlier than May 4, 1982 ~~not less than five days after filing~~. The revised schedules shall apply only to service rendered on or after ~~the~~ this effective date~~, thereof.~~

SS

2. On or after the effective date of this order, San Diego Gas & Electric Company (SDG&E) is authorized to file revised tariff schedules reflecting rates attached to this order as Appendix C, to be effective ~~not less than five days after filing~~ no earlier than May 4, 1982. The revised schedules shall apply only to service rendered on or after ~~the~~ this effective date.

SS

3. An annual reasonableness review of SoCal's CAM expenses shall be established; as part of its showing, SoCal is directed to provide daily operating records to all parties.

4. The $.00215 refund recollection factor in Long Beach's wholesale commodity rate shall be eliminated.

5. Consistent with this decision, an economic test for determining the prudency of long-term gas supply acquisitions shall be adopted for SoCal.

6. Consistent with this decision, an economic test for determining the prudency of discretionary gas purchases shall be adopted for SoCal.

7. Definition of "discretionary purchases" consistent with this decision shall be adopted.

8. SoCal shall submit in its next CAM proceeding an alternative proposal for allowing variable pricing of discretionary gas supplies.

9. SDG&E's Schedules GN-36/46 shall be canceled.

55 10. This order is effective today.

Dated APR 28 1982, at San Francisco, California.

(to be added)

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners