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ORIGINAL

Decision 84-12-067 December 28, 1984

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas rates and tariffs effective October 1, 1984, under the Gas Adjustment Clause. (Gas)	Application 84-08-067 (Filed August 20, 1984; amended October 1, 1984)

(See Appendix A for appearances.)

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O P I N I O N

Introduction

By this application Pacific Gas and Electric Company (PG&E) seeks to revise its natural gas rates under the Gas Adjustment Clause (GAC) in its tariffs. Anticipating changes in the price of gas from Canada and El Paso Natural Gas Company (El Paso) in the original filing, PG&E proposed no changes in rates and to forego the October 1, 1984 GAC $153.1 million increase.

On October 1, 1984 PG&E updated its application stating that its Canadian gas supplier, Alberta and Southern Gas Co. Ltd., had proposed a major price reduction in the export price for Canadian gas, pursuant to guidelines established by the Canadian government for development of new negotiated prices, which would decrease gas costs by approximately $176 million on an annualized basis. In addition, El Paso filed for an approximate $.11 per MMBtu reduction in the price of its gas, effective October 1, 1984. The updated filing included adjustments to the gas requirements and sales estimates reflecting Schedule No. G-59 and Schedule No. G-55 sales. The revenue requirement was adjusted to include updated Gas Cost Balance Account (GCBA) data through October 1, 1984.

The updated filing requests that GAC revenues be decreased by $192.2 million and that they go into effect concurrently with the $49.3 million increase requested in the 1985 attrition year filing and the $20.7 million increase requested pursuant to Decision (D.) 84-09-089 for the liquified natural gas (LNG) proceeding. The net effect of these adjustments would be to decrease gas rates approximately $122.2 million.

At the request of the administrative law judge (ALJ), in late-filed Exhibit 29 PG&E adjusted the $192.2 million to $201.0 million to take into account a revision of prices paid by PG&E for California gas due to a July 1, 1984 change from dry measurement to wet measurement. The result is a net decrease of $131 million in lieu of 122.2 million.

Public hearings were held in San Francisco on October 15, 16, 17, 18, 22, 23, 24, and 25, 1984. The application was submitted subject to filing of opening briefs on November 13, 1984 and reply briefs due November 27, 1984.

Evidence and testimony were presented on behalf of PG&E, the Commission staff (staff), and, in order of presentation, California Gas Producers Association (Gas Producers), El Paso, California League of Food Processors (CLFP), California Manufacturers Association (CMA), United States Borax and Chemical Corporation (Borax), Owens-Illinois, Inc., a group of cogenerators (Department of General Services of the State of California, Independent Power Corporation, International Power Technology, Inc., Simpson Paper Company, and University of California), and Toward Utility Rate Normalization (TURN).

Revenue Requirement

The GAC procedure allows PG&E to semiannually adjust its natural gas rates due to variations in the cost of purchased gas. Only gas costs are considered.

Though entitled to an increase of $153.4 million under its GAC tariffs, PG&E is not seeking to change its net revenue requirement but seeks an adjustment to its rates due to a reduction in the cost of gas from its primary suppliers, El Paso and Canadian gas.

PG&E's proposed net revenue requirement reflects a $49,339,000 increase requested in Advice Letter No. 1286-G for the attrition year allowance to be effective January 1, 1985 and a $20,676,000 LNG increase request as a result of D.84-09-089. The staff revenue requirement calculation assumed no G-59 enhanced oil recovery (EOR) sales, a lower cost of gas, disallowance of the attrition and LNG requested increases and inclusion of the ammonia surcharge as reflected in Southern California Gas Company's (SoCal) Application (A.) 84-09-022.

Following is the current revenue request as calculated by PG&E and staff, filed November 6, 1984 in Exhibit 29:

Table I

Pacific Gas and Electric Company
Gas Adjustment Clause
Calculation of Current Recovery Amount
And Revenue Requirement
PG&E vs. Staff

Forecast Period: 12 Months Beginning October 1, 1984

Line No.		PG&E M$	Staff M$
1	Current Cost of Purchased Gas	$2,775,443	$2,784,552
2	Plus: Gas Cost Balancing Acct.	248,983	248,983
3	Plus: Carrying Cost of Prepaid Gas	16,134	16,134
4	Subtotal	3,040,560	3,049,669
5	Plus: Adjustment for F & U Accounts Expense	24,142	24,214
6	Plus: Base Cost Amount	898,158	898,158
7	Subtotal	3,962,860	3,972,041
8	Less: Base & GAC Revenue at Present Rates	4,163,810	4,173,597
9	Total GAC Decrease	(200,950)	(201,556)

(Red Figure)

Lines 1, 5, and 8: GAC Decrease: Difference results from staff forecast of G-59 sales 2,680 MDth greater than G-59 sales in PG&E forecast. Staff forecast assumes G-59 sales beginning November 1984 whereas PG&E forecast assumes G-59 sales beginning in March 1985.

Line 2: Balance estimated for September 30, 1984.

Line 8: Present rates of August 12, 1984 excluding CFA, RCS, GEDA, SFA, PUC, and ASAC revenue and including $154,000 in revenue from returned check charges.

With the knowledge that PG&E had signed two new G-59 contracts, the staff agreed to including aproximately 23 Bcf of EOR sales. With this difference in sales eliminated, the difference in the projected cost of gas between staff and PG&E is minimal. We will adopt the staff estimate as reasonable.

TURN advocates a reduction about $70 million greater in revenue requirement than is proposed by PG&E and staff. TURN proposes that for the date for calculating the GCBA be December 31, 1984 rather than September 30, 1984 as used by PG&E and the staff. PG&E states that it would prefer to use a December 31, 1984 figure calculated using recorded October and November sales. We agree with PG&E and will use recorded October and November data to calculate a December 31, 1984 GCBA balance. The most recent estimate for the year-end GCBA balance was obtained from PG&E on December 14 and is $204,367,000. We will use this balance in calculating the GAC revenue requirement. Thus the GAC decrease will be about $45 million greater than that proposed by staff or PG&E.

TURN also proposed an adjustment to the El Paso minimum bill of $15,268,000. Under tariffs filed with the Federal Energy Regulatory Commission (FERC) by El Paso, PG&E receives a credit for purchases in excess of a 75% minimum. The credit amount is determined by the purchases of both PG&E and SoCal. TURN would impute a credit of $10,015,000 for SoCal's purchases based on SoCal's estimates for its current Consolidated Adjustment Mechanism (CAM) proceeding and reflect a credit of approximately $5.3 million for PG&E's purchases. Based on the testimony of El Paso's witness, PG&E does not object to the proposed adjustment for its purchases but takes exception to the inclusion of the SoCal estimates based on SoCal's operations into a PG&E proceeding. We have adopted those estimates in our decison on the SoCal CAM, therefore it seems reasonable to make the full $15.3 million adjustment for both PG&E and SoCal purchases. In general, we are more comfortable in making adjustments for prospective minimum bill credits when the adjustment is based on an uncontroverted short-term sales forecast of less than four months, even if that forecast is part of a different ongoing proceeding.

TURN's final proposed adjustment concerns PG&E's Supply Adjustment Mechanism (SAM) billing adjustment. TURN proposes an adjustment to account for what it terms an "automatic undercollection" in the SAM account resulting from PG&E's 1984 billing lag adjustment. TURN states:

> "PG&E's balancing account calculation includes, in the month of May 1984, an adjustment of $2,572,000 to reflect the 'billing lag' effect of the January 1984 Base Cost Amount increase (Ex. 2, p. C-3, line 23). This adjustment was intended to comply with the terms of Decision No. 84-02-003 (2/1/84), but TURN submits that it does not accomplish the correct result."

PG&E states that it applied the adjustment to cycle-billed customers who comprise approximately 76.21% of the January 1984 sales as directed by D.84-02-003.

We agree with PG&E that the language of D.84-02-003 is clear and that sales to noncycle-billed customers should not be included in the SAM adjustment.

We will approve today a 1985 attrition increase of $45 million for PG&E's Gas Department, and an increase of $19 million to cover LNG costs recoverable under D.84-09-089. These increases totalling $63,574,000 will be applied against the GAC decrease.

Taking into account all of the above, the GAC revenue requirement reflects a net decrease in gas rates of $193,485,000. Table II shows the development of the GAC revenue requirement.

Natural Gas Requirements

Except for EOR G-59 forecast, PG&E and the staff are in agreement with the gas requirements. Table III shows the gas requirements for the forecast period October 1984 - September 1985.

Table II

PACIFIC GAS & ELECTRIC COMPANY
GAS DEPARTMENT

12 MONTHS BEGINNING OCT 1, 1984

GAC REVENUE REQUIREMENT

Line No	Item	M$
1	Current Cost of Purchased Gas	2769237
2	Plus Gas Cost Balancing Account	204367
3	Plus Carrying Cost of Prepaid Gas	16134
4	Subtotal	2989738
5	Plus Adjustment for Fran. & Uncol Acct Exp @ .794%	23739
6	Plus Base Cost Amount (1)	961735
7	Ammonia Surcharge Adjustment	4900
8	Subtotal	3980112
9	Less Base & GAC Revenue @ Present Rates (2)	4173597
10	Difference	-193485
11	Plus Revenue @ Tariff Rates (3)	4282569
12	GAC Revenue Requirement	4089084

(1) Excludes Other Operating Revenues of $3600

(2) Includes Returned Check Revenue

(3) Commodity Rates Effective Aug 12, 1984

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Table III

Natural Gas Requirements
Forecast Period, October 1984 - September 1985
(MDth)

Class	Total
Residential	197,634
Commercial	120,368
Industrial G-50	72,044
Cogeneration	8,292
Industrial G-58	35,234
G-80, G-82, G-84	14,214
Total Industrial	129,784
Edison	4,201
Resale	8,417
PG&E Steam Electric	294,166
Other Inter-departmental	1,237
Total Inter-departmental	295,403
Enhanced Oil Recovery	24,382
Total Gas Sales	780,189
Gas Dept. Uses	5,114
Losses and Unaccounted for	12,309
Total Requirement	797,662

Residential and Commercial

For residential and commercial sales PG&E utilizes econometric and end-use methodologies to forecast sales, which also take into account the forecasted load reducing impacts of conservation standards and programs. The forecast of 197,634 MDth for residential sales is consistent with the forecast in the last GAC and the most recent adjusted twelve months recorded data.

PG&E has made some changes in its commercial forecasting econometrics equation which the staff believes to be reasonable. Given an assumed $.71577 commercial rate, and in view of the lower current and forecasted rates, the forecasted sales may be too low, although it is about 3% more than the latest twelve months recorded data. Such sales are fairly inelastic in the short run and PG&E's forecast appears reasonable.

Interruptible

Interruptible sales include sales to P-3 and P-4 industrial customers, G-58 customers, the new G-80, G-82, and G-84 rates, Southern California Edison Company (Edison), EOR load, and interdepartmental load. Sales to industrial customers are estimated by using an econometric equation. Edison determines its Coolwater facility requirements and informs PG&E. EOR sales are estimated by PG&E after discussions with customers. Interdepartmental sales include sales for construction, operations, steam heat, and electric generation; over 99% of interdepartmental sales are for PG&E's electric generation. This sales component is a function of electric load requirements and is dependent upon how much of this load can be met by other sources of electric generation.

Interruptible Sales - Industrial

PG&E forecasts industrial sales (not including EOR sales) of 129,784 MDth, which exceeds the last GAC forecast (117,308 MDth) and the most recent twelve months recorded data (105,000 MDth through June 1984). It expects industrial sales to be higher for the present GAC period because the gas service area economy is forecasted to experience higher levels of economic activity than were forecast for the previous GAC.

Rate design innovations adopted in recent proceedings and, to an extent, those proposed by staff and PG&E herein, coupled with declines in gas costs, will provide additional industrial incentive to use gas. It is not unreasonable to anticipate some favorable reaction in response to the proposed changes. First, the positions of the intervening industrial customers all support the proposed rate changes. Second, PG&E testified that its proposed G-50 Tier 3 and G-58 rates of 39¢ per therm would, if adopted, generate additional sales of 190,640 M therms and some $14 million additional contribution to margin in the forecast period using 36.074¢ per therm as the cost of gas. (These sales were not included in PG&E's forecast.) It must be recognized, however, that a reduction from the current 47.5¢ to 39¢ would result in a decreased contribution to a margin of $27 million at forecasted sales levels for G-50 and G-58. PG&E did not include the additional G-50 and G-58 39¢ per therm sales in its forecast (nor did the staff) partly because of the timing and selectivity of updates and partly because of the impreciseness of forecasting on the basis of price alone. Recapture of former customers as well as attraction of new customers are anticipated by PG&E with the lower rate.

According to PG&E, the requirements forecasts for the different industrial rate classifications are derived from the requirements forecast of the industrial forecasting equation using historical data on the split of industrial sales into its rates schedule classifications. Little historical data exist for the G-58 rate schedule and none exists for G-80, G-82, and G-84. However, the G-80 series of rates were included in PG&E's forecast and, in fact, account for most of the increased forecast since the last GAC. Given the uncertainties of forecasting industrial sales, PG&E's forecast appears reasonable and the 72,044 MDth for G-50, 35,234 MDth for G-58, 8,292 MDth for cogeneration (G-55A), and 14,274 MDth for G-80, G-82, and G-84 will be adopted.

EOR Sales

PG&E first estimated EOR sales of 42,253 MDth, with sales expected to begin in January 1985. The updated filing forecasts sales of 21,702 MDth, with sales commencing in March 1985. The proposed G-59 rate is 38¢ per therm. In A.83-08-38, PG&E forecast EOR sales between October 1983 and September 1984 of 62,429 MDth. No EOR sales were recorded for that time period. In A.84-03-07 PG&E forecast sales of 28,715 MDth to occur between June 1984 and March 1985. The latest forecast does not expect any EOR sales until March 1985.

The absence of sales appears attributable to a combination of the high investment necessary by the customer, the lengthy time involved to install necessary equipment after a decision to buy, and the lack of attraction at the proposed 38¢ per therm rate.

At the hearing, the staff witness testified that he was informed by PG&E that it had in fact obtained two EOR customers which would purchase some 25½ Bcf annually commencing November 1, 1984, that these sales were apparently in addition to PG&E's forecasted G-58 sales and therefore would generate additional revenues to PG&E, that a 38¢ per therm rate would apply, which would provide a contribution to margin of about 5¢. The staff accepted the 5¢ contribution as appropriate and while a lower G-59 rate might generate more EOR sales, the reduced contribution renders that lower rate unacceptable to staff.

The staff therefore revised its forecasted sales to include the level of sales resulting from those two contracts at 38¢ per therm. PG&E did not revise its forecast in which a comparable level of sales (albeit to different customers) is included. This is the only difference between the staff and PG&E for gas sales requirements.

Steam Electric

PG&E originally forecast steam electric sales of 227,631 MDth. This assumed full commercial operation of Diablo Canyon Unit No. 1 beginning September 1, 1984. Given more recent information about Diablo Canyon and the Commission's policy of not including Diablo Canyon in the determination of rates until commercial operation begins, at the staff's request, PG&E provided a forecast with no Diablo Canyon generation in the forecast period of 294,166 MDth.

Losses and Unaccounted-for Gas

Losses and unaccounted-for gas is determined as the difference between gas volumes measured into the PG&E pipeline system (purchases from suppliers and receipts from underground storage) and gas volumes measured out of the PG&E gas system (sales to customers and deliveries to underground storage) over the same period of time, adjusted for changes in pipeline system inventory. Losses and unaccounted-for gas reflect differences in the measurement characteristics of metering devices measuring gas into and out of the PG&E gas system, comparison of calendar period receipts to cycle billing sendout data, and unaccounted-for physical losses from the PG&E gas system.

In the last GAC, PG&E's estimate of 18,364 MDth was based on an econometric equation dependent on seasonal factors and temperature variation, and 18 years of historical data. In D.84-08-116, the Commission used a 10-year average (1974-1983) of 16,586 MMcf. The average between 1974 and 1978 was 21,280 MMcf, and between 1979 and 1983 was 11,893 MMcf. PG&E's current forecasts of losses and unaccounted-for gas uses only data from 1979 forward. This is appropriate since losses and unaccounted-for gas decreased substantially after 1978.

PG&E's forecast of 12,309 MDth, which is about equal to 11,893 MMcf and is consistent with the recent trend of lower losses and unaccounted-for gas. The decrease in the forecast from 18,364 MDth to 12,309 MDth decreases forecasted purchased gas costs by about $21,000,000.

Other Requirements

Other requirements are gas department uses and resale requirements. Both are forecasted through the use of an econometric equation. PG&E's forecasts for gas department uses, 5,114 MDth, and for resale customers, 8,417 MDth, will be adopted.

Sequencing

When available gas supplies exceed the existing demand, it requires the utility to decide which supplies to purchase and which to turn back. While the actual operation of the utility system remains the ultimate responsibility of management (subject to reasonableness review of the costs incurred), this Commission has in recent years utilized the GAC proceedings as a forum for the evaluation of sequencing policy on a prospective basis. As a result, various guidelines have been established to assist the company in its day-to-day decisions on gas purchasing. It is important to keep in mind, however, that sequencing policies are simply guidelines. PG&E must and does retain the flexibility to adjust its practices on an ongoing basis to adapt to new circumstances and changed conditions.

The major sequencing issue in this proceeding is whether supplies should continue to be taken on a least-avoidable-cost-first basis, as they generally have been in recent years, or whether an average cost test should be substituted. Unlike the situation in the current SoCal CAM proceeding, A.84-09-022, there is a relative consensus among parties here that average cost should become the sequencing guideline for purchases from PG&E's two largest suppliers - El Paso and Canada.

Avoidable cost sequencing disregards all fixed costs that must be paid regardless of the level of gas purchases. Thus, the supply with the lowest variable cost is taken first. This produces a least-cost gas supply mix. Because it ignores all fixed charges, an avoidable cost policy provides little or no incentive for suppliers to minimize their total costs over the longer term. Further, avoided cost calculations are very sensitive to suppliers' rate designs. Thus, by shifting certain costs from the commodity charge to the demand charge, a pipeline can gain a more favorable sequencing price without reducing costs at all.

In contrast, average cost sequencing is not particularly sensitive to suppliers' rate designs, and does create an incentive for minimization of all costs, variable and fixed. A shortcoming of average cost sequencing is that it does not necessarily achieve a least-cost supply mix in the short term.

PG&E's Proposed Revised Gas Purchase Sequence

PG&E is proposing to change its gas purchase sequence in connection with the change in price of El Paso and Canadian gas. The principal difference from the present sequencing policy is that there would be annual percentage equivalent treatment for all Canadian and El Paso discretionary gas in comparison to the current limitation of that treatment to approximately 60% of the authorized Canadian supply and El Paso availability, with El Paso gas given preference after that.

While this change appears relatively simple, it is actually complicated, involving the assessment of the policies underlying the present sequence, and the development of certain conclusions with respect thereto. It is believed that the new Canadian pricing policy should not only bring about significant purchased gas cost savings, but also signal a new era of competition among PG&E's gas suppliers and a major change from the situation of significantly disparate supplier prices which led to the present avoidable/unavoidable cost sequencing guidelines.

To achieve a least-cost mix, PG&E currently schedules its supplies in order of ascending incremental costs once contract minimums, regulatory directives, and operating constraints have been satisfied. The gas sequence proposed is the same as the sequence presently in use for its gas system operations. After contractual and operational minimums are satisfied, PG&E takes discretionary California gas priced less than the applicable El Paso and Canadian prices. Then discretionary El Paso and Canadian gas are purchased to achieve a percentage equivalent level of takes from each supplier, up to a 60% level on an annualized basis. Then, in the following order, remaining discretionary El Paso, California, and Canadian gas are taken.

Discretionary California gas, which is purchased at the Section 102 price, is sequenced prior to Pacific Gas Transmission Company (PGT) takes above 60%, even though such action results in slightly higher purchased gas costs. PG&E made this decision because the average California price was so much lower than the average PGT price. PG&E states that to sequence this segment of PGT purchases ahead of discretionary California gas would conflict with its goal of continuing to send signals that the presently effective average Canadian price must drop.

The El Paso PGA reduction became effective on October 1 and the Canadian price reduction was to be effective on November 1. For the forecast period PG&E proposes no change for October but beginning November 1 the following sequencing would become effective:

1. California gas minimums.
2. El Paso gas minimums.
3. Canadian gas minimums.

4. Rocky Mountain gas minimums, contract obligation volumes, and discretionary volumes with a delivered cost less than the incremental commodity cost of El Paso and Canadian gas.

5. California gas to contract obligation.

6. California gas above contract obligation with a commodity cost less than the incremental commodity costs of El Paso and Canadian gas. (Until January 1, 1985, also includes California gas currently priced lower than the effective El Paso gas sequencing cost.)

7. Canadian and El Paso discretionary gas, and California discretionary gas with a commodity cost approximately equal to the lower of the incremental commodity cost of El Paso and Canadian gas, on an annual percentage equivalency basis.

8. Remaining California gas to maximum.

9. Remaining Rocky Mountain gas to maximum.

This proposal differs from the current sequencing primarily in applying percentage equivalency treatment to <u>all</u> Canadian and El Paso discretionary gas versus the current sequence's limitation of that treatment to approximately 60% of the authorized PGT volumes and El Paso availability, with El Paso gas given preference after that.

PG&E states that developing a sequencing policy involves consideration of factors which are subject to change, as well as being difficult to define and quantify. It states, in arriving at a sequencing recommendation, it has balanced a number of competing signals that do not always point in the same direction. The policy developed weighs average cost considerations, incremental cost issues, and supply reliability concerns in addition to being designed to encourage PG&E's suppliers to provide competitively priced, reliable service for the longer term. The policy recommended serves these goals by treating suppliers in a balanced manner while generally avoiding unnecessary cost incurrence in the near term.

PG&E states that making its assessment of the gas purchase sequence for the supply arrangements to its market led to the following general conclusions:

"(1) The gas purchase sequence has been and should continue to be used as a means of obtaining competitive gas supply arrangements.

"(2) The gas purchase sequence now in effect has not been formulistic. Short- and long-term policy considerations, essentially nonquantifiable in nature, have been applied as an overlay to incremental cost analyses. A nonformulistic approach should continue to be applied.

"(3) There are different structures and rate designs and different regulatory frameworks for each of PGandE's gas supplies. As a result, it will never be possible to make a fully 'apples and apples' comparison of PGandE's supply arrangements. The present 'avoidable,' incremental cost sequencing policy represents one attempt to put PGandE's supplier prices on a comparative footing for sequencing purposes. However, even that approach does not achieve a complete 'apples and apples' comparison and other judgmental factors enter in. Therefore, no policy may be theoretically consistent in all respects. Instead, the emphasis should be on how the policy impacts both near and long-term gas costs and supplies, and on how it encourages (or discourages) competitive, reliable supply arrangements, with suppliers treated equitably and put in a strong position to provide reliable service in the future.

"(4) Average cost considerations already play some role in PGandE's discretionary gas purchase sequence, as now in effect and approved in Decision No. 84-08-115. Considering the above conclusions and the new competitive pricing environment, greater emphasis should be placed on relative average costs--particularly in the case of the Canadian and El Paso supplies. This change in emphasis recognizes that suppliers should be discouraged from using rate design to increase sales without actually reducing overall prices, and that suppliers should compete on the basis of their respective overall current costs. In this way, increased recognition of average costs should encourage PGandE's two major suppliers to minimize fixed as well as variable costs.

"(5) While average cost concepts must be emphasized more--particularly in looking at El Paso and Canadian gas discretionary sequencing--many elements of the present 'avoidable,' incremental cost approach continue to have validity in the new competitive framework."

PG&E then applied these general conclusions to projected price and cost relationships as follows:

"a. El Paso Versus Canadian Gas

"In computing average Canadian and El Paso prices, costs such as the respective commodity and demand charges, El Paso's minimum bill and Canadian take-or-pay carrying costs have been considered. For example, assuming Canadian and El Paso takes approaching a 70% load factor under a percentage equivalent sequencing approach, the average delivered cost of Canadian gas at the California border would be approximately \$3.63 per MMBtu, measured dry. At these load factors, PGandE would not be incurring additional take-or-pay. Therefore, avoided carrying costs on future take-or-pay are not part of this amount. However, the average cost of \$3.63 per MMBtu does recognize the carrying costs now being paid by PGandE ratepayers for the already incurred Canadian take-or-pay in PGandE's Gas Cost Balancing Account.

"Current year carrying costs chargeable to ratepayers at the present balancing account short-term commercial paper rate have been included. Such costs represent $0.06 per MMBtu of the $3.63 per MMBtu amount.

"Similarly, the average cost of El Paso gas is based on three components: (1) a per year demand charge, (2) the commodity charge, and (3) minimum bill payments. For example at a load factor of El Paso availability in the same range as that used for the average Canadian delivered price referred to above, the El Paso average cost, assuming the eventual effectiveness of its 60 percent minimum bill settlement, is estimated at $3.65-3.66 per MMBtu on November 1, 1984.

"With the October 1, 1984 El Paso price and rate structure, and the proposed Canadian price, the Canadian and El Paso average costs are generally similar although there is greater divergence at lower load factors. This similarity in average costs suggests that as changes are made in discretionary gas purchases between El Paso and Canadian gas at the kinds of load factors expected over the forecast period, there will not be significant changes in total purchase costs. A second implication of generally similar average cost curves over a wide range of load factors is that small changes in costs by supply sources, or an increase/decrease in load, should not create a preference for changes in the sequencing order.

"In addition to an average cost comparison, PGandE also has reviewed the El Paso and Canadian price relationships on an incremental basis. The incremental cost of El Paso gas is highly dependent on the El Paso minimum bill and the degree to which the Account 191 surcharge is recognized. Effective October 1, 1984, the El Paso commodity price is $3.45 per MMBtu. If that price is adjusted for 75 percent of the Account 191 surcharge now in effect (as provided in CPUC Decision No. 82-12-111), the El Paso incremental cost would decrease by $0.1234 per MMBtu to become $3.3288. If the El Paso load factor were below the minimum bill level, the incremental El Paso price would be reduced further to approximately $3.05 or $2.95 per MMBtu, respectively, with the proposed 60 percent minimum bill or the 75 percent minimum bill now in effect subject to refund.

"In comparison, the proposed new Canadian price would produce an incremental sequencing price in the range of approximately $3.00 to $3.05 per MMBtu for load factors at or above the proposed 50 percent take-or-pay threshold and up to 70 percent. The incremental sequencing price includes the incremental compressor fuel usage on the PGT system, and the Gas Research Institute adjustment charge authorized by FERC and included in PGT's tariff. If the Canadian load factor were below the proposed 50 percent take-or-pay level, the incremental Canadian price would drop, due to recognition of avoided carrying cost on future take-or-pay and reduced incremental compressor fuel usage, as discussed further below.

"This illustrates that above the proposed 50% take-or-pay level for Canadian gas, on an incremental basis, Canadian gas costs may be viewed to be generally competitive with the various incremental El Paso gas prices possible, under either a 75% or 60% minimum bill scenario for El Paso gas. However, if the comparison is made at higher load factors, when it is not necessary to factor in minimum bill effects, or if the Account 191 adjustment is eliminated, the comparison is less favorable, and on an incremental cost basis Canadian gas could appear to be the less costly alternative.

"The Account 191 surcharge issue has been debated for some time. PGandE is not recommending a specific change in the present surcharge adjustment, nor, however, is the Company recommending that major shifts in takes be based on the adjustment. The present Decision No. 82-12-111 approach (i.e., deduction of 75 percent of the Account 191 surcharge) has encouraged lower California-source gas prices. Elimination of the adjustment should not be allowed to create pressure for higher California prices with no related consequences for the Company's level of California purchases. The Account 191 surcharge itself has been reduced significantly. With the effectiveness of El Paso's October 1 PGA adjustment, the surcharge is $0.1645 per MMBtu; the 75 percent amount of this figure used for sequencing is $0.1234 per MMBtu--representing a $0.15 per MMBtu reduction below the Account 191 surcharge amount used for sequencing in the El Paso PGA period just concluded. PGandE also would not recommend that its future level of Canadian versus El Paso purchases turn on elimination of the surcharge adjustment--i.e., Canadian gas measured on an incremental basis should not be preferred over incrementally priced El Paso gas without the surcharge adjustment, if the average price of the two supplies on a current cost basis is essentially the same.

"PGandE's present policy of annual percentage equivalent sequencing of El Paso and Canadian gas up to a 60 percent level is based on price and cost relationships at the present 60 percent Canadian take-or-pay level and the less certain El Paso minimum bill level. Assuming Canadian and El Paso prices are competitive on the average after considering current take-or-pay and minimum bill costs, the issue arises as to PGandE's future gas purchase sequence at levels below the then effective take-or-pay and minimum bill amounts. A part of the pending Canadian proposal is to reduce the take-or-pay level to 50 percent effective November 1, 1984. Meanwhile, if the El Paso settlement becomes effective, the El Paso minimum bill would be based on 60 percent of 1140 MMcf through June 30, 1985 and would be subject to change thereafter in connection with El Paso's next scheduled (July 1, 1985) change in its base rates. Applying strict incremental cost principles, there would appear to be a preference to purchase Canadian gas to avoid additional take-or-pay over purchases of El Paso gas to avoid minimum bill payments even when Account 191 impacts are included. Compare, for example, an El Paso incremental sequencing price of $3.05 per MMBtu below the proposed 60% minimum bill, to a Canadian incremental sequencing price under the new pricing proposal of about $2.60 per MMBtu for purchases in the 40-50% range, and assuming only one year until make-up.

"Perhaps more important, however, is PGandE's overall policy objective to treat its two major suppliers on a balanced basis assuming prices which are competitive on the average. Under the price and cost relationships anticipated for November 1, 1984, such a balanced approach to the Canadian and El Paso supplies would be justified. This is borne out by the overall cost analysis discussed below. These price and policy considerations have led PGandE to the conclusion that on November 1, 1984, assuming the new Canadian arrangements are in place, discretionary El Paso and Canadian gas should be purchased on an annual percentage equivalent basis below as well as above the applicable take-or-pay and minimum bill levels.

"PGandE has looked at the total cost impacts of altering the present sequence in the manner proposed. Under the presently effective sequence, the decrease in Canadian gas costs would result in a total $176.6 million savings associated with purchases over the export license year beginning November 1, 1984. The new sequence described above would increase those total savings to $183.5 million. If discretionary Canadian gas were taken before El Paso discretionary gas, based on strict application of incremental cost considerations, the total savings would be approximately $180.4 million. These figures demonstrate that different sequences, with dramatic differences in takes from various sources, would produce gas cost results for PGandE's gas system which are very similar, and for which the differences are minimal in the context of PGandE's overall gas costs.* That conclusion reinforces the principle that when the overall El Paso and Canadian gas prices are in the same range, neither supplier should be preferred over the other. The sequence proposed by PGandE meets that criterion by taking all Canadian and El Paso discretionary gas on an annual equivalent percentage basis.

"* The figures used for these comparisons were developed on a more generalized basis from short-term fuels planning forecasts and do not reflect the adjustments to such forecasts which have been made for purposes of Application No. 84-08-067.

"There is a separate issue concerning nondiscretionary El Paso and Canadian gas in light of the proposed revised Canadian arrangements. Under the Canadian proposal, the existing contractual minimum physical take requirements would be removed. Hence, PGandE would be looking at both the nondiscretionary El Paso and Canadian volumes from the standpoint of minimum operating requirements. The operational minimums for El Paso gas are primarily related to conditions on the southern portion of PGandE's system, while the operational minimums for Canadian gas are primarily a function of conditions on the northern part of the system. On the southern part of PGandE's gas system, operational minimums tend to be primarily driven by off-line loads, i.e., sufficient El Paso gas must be taken to meet the load served directly off of PGandE's Main 300 transmission line. In the northern part of the system, operational minimums tend to be influenced by supplier and system operational constraints, as well as by off-line loads. For these reasons, the operational minimums for both El Paso and Canadian gas will fluctuate considerably. For El Paso gas, the minimum daily off-line requirement is approximately 500 Mdecatherm in winter and 250 MDth in summer. For Canadian gas, the minimum daily off-line requirement is estimated to be between 250 MDth and 450 MDth per day. The PGT and northern PGandE pipelines have never been operated at these levels in their present configurations. Consequently, the minimum operational levels for Canadian gas are uncertain. PGandE estimates that operations below the top end of the range could not occur over protracted time periods given the present transmission system. Further, over the forecast period, PGandE is not projecting that either its El Paso or Canadian purchases would be at such minimum operating levels for any protracted period of time.

"b. California Gas

"PGandE's California gas supply differs from the El Paso and Canadian supplies because PGandE negotiates directly with the producers and buys the gas on a well-by-well basis. The California supply is also much closer to the market. In recent times, producers with a significant percentage of California gas have responded to PGandE's discretionary gas sequencing policy by lowering their prices to keep their gas competitive. PGandE feels that its sequencing policy should continue encouraging California producers to compete in PGandE's market and should reward producers whose prices are competitive. It would be irrational to adopt a sequencing policy which encouraged California producers to raise their prices or even to hold the line when the clear trend nationwide--and internationally--is for lower prices. California production specially that priced under NGPA Section 102 is priced far above the level that is being seen across the nation in price renegotiations.

"In light of the existing El Paso and proposed Canadian demand-commodity rate structure, however, the question is whether the California producer should be required to compete with the average prices or the incremental commodity costs of those out-of-state supplies. PGandE believes that California gas should compete with the incremental commodity cost. To receive a preferential place in the sequence, California gas should be priced at a level below the incremental commodity cost of the El Paso and Canadian supplies. This recommendation is made because California gas itself is priced solely at a commodity cost, and to do otherwise could yield <u>higher</u> not lower gas costs. Since a key benefit of PGandE's indigenous California supply is its proximity to the market, this benefit effectively saves PGandE's customers the costs (beyond gathering costs) of getting the California supply to market. If California gas were sequenced solely in relation to the average delivered cost of PGandE's out-of-state supplies, the Company would be recognizing the distance factor in a manner that would shift the benefit from the customer to the California producers. As a result, the California producers would be able to charge more for their gas, even though the actual commodity cost of the interstate supplies was lower. To preserve the proximity benefit of California gas for California consumers, the California producers should be required to make their prices compete with the incremental El Paso and Canadian commodity costs in order to receive a preferred position in the sequence.

"Finally, in recognition of their reliance on the previously effective $3.28 per MMBtu sequencing guideline, per Decision No. 82-12-111, PGandE is not proposing to penalize those California producers who dropped their price in response, to achieve an improved place in the sequence. Thus, until January 1, 1985, when such prices will be renegotiated, PGandE proposes to continue to sequence such California gas before discretionary El Paso and Canadian gas. Thereafter, however, PGandE proposes to be guided by the policy outlined above, which means, for example, that a $3.20 per MMBtu California price would no longer qualify for such a preferred place in the sequence.

"c. GEDA Gas

"The use of average cost as a measure of competition for Canadian and El Paso gas also raises the question of how GEDA costs should be considered. Using the average cost of GEDA gas would require that the investment expense of the GEDA wells be considered for sequencing. However, this makes little sense given the fact that such investments have been ratepayer funded. Therefore, PGandE is not proposing to change its present policy on the exclusion of such sunk costs for sequencing purposes.

"d. Spot Sale Gas

"In addition to traditional sources of supply, PGandE may increasingly find itself confronted with the question of whether to buy gas from 'spot sale' sources, such as El Paso's Special Transportation Program (STP). Therefore, PGandE must have a sequencing policy on 'spot sale' gas. By its very nature, 'spot sale' gas is an incremental source at an incremental price. For that reason, it would be unfair and inappropriate to compare an incremental 'spot sale' price against an average cost for a committed supply since the latter includes all avoidable and unavoidable costs. Consequently, PGandE proposes to continue to emphasize incremental costs in evaluating 'spot sale' gas as compared to committed supplies.

"Using incremental cost relationships still leaves the question of whether or not 'spot sale' gas should be taken in preference to gas from committed sources when, on an incremental basis, their prices are in the same general range. Given PGandE's long-term goal and need to maintain all of its traditional suppliers in a strong and balanced position, PGandE believes that 'spot sale' gas should not be purchased before traditional committed supplies unless a clear and significant cost advantage can be shown.

"EL Paso's STP Progam and FERC's extension and expansion of special marketing programs at its meeting on September 26, 1984 (PGandE has not yet seen the FERC order) point out the need for CPUC rate design changes to allow PGandE gas sales to interruptible markets at rates which truly are competitive with alternate fuel or direct gas sale prices. However, that does not mean that PGandE must purchase 'spot sale' gas in preference to its committed supplies to achieve such results--the incremental cost of the committed supplies could itself be considered in designing alternate interruptible rates."

Staff

The staff addressed PG&E's proposed sequencing with these questions: (1) Should PG&E follow an absolute least-cost sequencing order for its entire gas purchases or are there any remaining contractual or operational limitations that would make doing so inadvisable? (2) How should PG&E define the sequencing price used for least-cost sequencing purposes? (3) How should the essentially similar sequencing prices be compared?

The Public Staff Division addressed each of these concerns at length and put forward recommendations for each area.

The staff recommends that a core purchase[1] concept for gas supplies purchased by PG&E be adopted by the Commission. It states the record is uncontradicted that the pipelines supplying gas to northern California would face substantially increased risk if their sales volumes were to drop below either their fixed volume contract levels or their fixed operational requirement levels as a result of the almost unlimited flexibility granted to distribution companies by Federal Energy Regulatory Commission FERC Orders 380A and 380C. The staff states that a core gas take based upon operational requirement limitations in each pipeline system provides each pipeline with some minimum assurance that low gas takes will not force it to breach fixed volume contracts or to shut down facilities due to a lack of sufficient flow of gas. Because the minimum take provisions remain only in those contracts between PG&E and California gas suppliers as a result of FERC Order 380C, the staff recommends that PG&E sequence gas which it is required to purchase under contracts with California producers first and that it endeavor to negotiate lower minimum take requirements with its California producers to bring those requirements more in line with the situation involving interstate pipeline suppliers. After minimum contractual purchase obligations have been accounted for, it must be determined whether operational constraints of the pipeline suppliers or PG&E require additional core takes of gas. Staff states there are significant operational constraints both for PG&E's pipeline suppliers and for PG&E. The staff recommends adoption of PG&E's proposed core purchase levels since they cover most of PG&E's pipeline operational constraints and all of El Paso's and are based on genuine constraints imposed by PG&E's system.

For determining the sequencing price, the staff urges the use of average cost rather than avoided cost stating that it holds many distinct advantages.

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[1] Core purchases are nondiscretionary gas taken for operational and/or contractual reasons.

First, average cost sequencing encourages the gas supplier to minimize all of its costs, both fixed cost and operational, as well as the cost of purchased gas. It is alleged this makes a powerful incentive for producers to keep the price charged distribution companies at a minimum. In contrast, avoided cost sequencing creates a situation where pipeline suppliers are encouraged to "front-load" their fixed costs into demand charges which are considered "unavoidable" and thus removed from the cost of the gas for sequencing purposes.

Further, staff states average cost sequencing is well suited to the characteristics of PG&E's gas supply system. The majority of gas is provided by two large transmission pipelines. The two pipelines are roughly equivalent in size and availability of gas, are well depreciated in their useful lives, and are able to compete with each other on an equal basis. This is not necessarily the case in southern California where, for example, established pipelines like El Paso and Transwestern Pipeline Company compete with far newer and smaller pipelines such as the Pacific Interstate Transmission Company (PITCO), an affiliate of SoCal which brings gas from Canada through a prebuilt portion of the ANGTS, or the Pacific Offshore Pipeline Company (POPCO) pipeline from the Hondo Point project operated by Exxon.

Staff states PG&E has also recognized the usefulness of comparing PGT and El Paso supplies on an average cost basis and in fact has adopted that as one of its primary tests for comparing the gas from the two systems. PG&E has stated that its objective is to treat the two major suppliers "on a balanced basis assuming prices which are competitive on the average." Where the two major suppliers are able to compete on an essentially equivalent basis, use of average cost sequencing provides a significantly simpler and more comprehensive incentive for the pipelines to reduce all costs and avoids the manipulation of pipeline rate design to achieve sequencing advantages.

To eliminate the potential for manipulating average cost sequencing prices, the staff recommends that the Commission select a sales volume to be applied uniformly to all suppliers, on a percentage of suppliers' contract quantity as the basis for calculating the average sequencing price. The staff recommends that 75% of contract quantity be used as the basis for making the comparison of average cost. This volume is approximately the design sales volume embedded in El Paso's commodity rates, over which El Paso's entire fixed cost of service is allocated and compares with the fixed cost of service for the PGT system allocated over a similar sales volume. The 75% could also be used in developing the unit gathering charges for California suppliers. Because PGT is a cost-of-service pipeline, it has no embedded sales design volume reflected in its rates. The staff states its proposal would help put the two pipeline systems on equal footing for purposes of comparing their average costs. Staff believes that it is of the utmost priority for the Commission to select a particular percentage of a supplier's contract quantity and to maintain this percentage level for a substantial period of time as the basis for calculating average costs for sequencing purposes.

Should the staff recommendation not be accepted, staff urges elimination of the Account 191 surcharge adjustment. Staff states this adjustment offers pipeline suppliers an incentive to manipulate both sales estimates and cost estimates to obtain a sequencing advantage. While none of the parties to this proceeding has alleged that such manipulations have actually occurred, the more competitive gas market and the reduction of gas prices to a generally similar overall level place a much greater premium on a pipeline supplier's sequencing position. As the difference between the commodity prices charged by pipeline suppliers shrinks to 1, 2, or 3¢

advantage in price may mean a tremendous difference in sales for the pipeline whose gas is sequenced on an incremental or avoided cost basis.

In urging adoption of average cost sequencing the staff states it developed a methodology for determining a sequencing price for California source gas that properly reflects the embedded ratepayer investment in the gathering system that moves the California gas from the wellhead into PG&E's system. If there was no California gas production, this portion of the rate base would not exist. Therefore, the staff recommends that the cost of service associated with this gathering system be considered part of the total cost of California gas. The sequencing price for California gas would thus be the wellhead price plus a unit charge representing the cost of service for PG&E's gathering system. If California gas is to be sequenced ahead of available out-of-state supplies then the wellhead price of the California gas must be no greater than the out-of-state supply less the gathering system charge.

Because PG&E was unable to provide a precise estimate of the cost of service associated with its gathering system, the staff proposes that the Commission use an interim price of 34¢ per decatherm for the gathering system costs until the precise value is available. The 34¢ per decatherm was developed through the staff's analysis of the El Paso gathering system which uses a reasonable method for allocating the El Paso production cost of service.

Staff asserts that PG&E's proposal to price California gas is really structured on an incremental cost basis and will lead to considerable confusion regarding the basis for sequencing policy, subject to considerable manipulation by PG&E. While not suggesting any manipulation would take place, staff states if competition is to work in the gas markets, the suppliers must understand what the consequences of their actions are to be which requires an understandable and believable gas sequencing policy.

The staff acknowledges that by adopting an incremental sequencing policy, the sequencing price for California discretionary gas would be $3.00 per decatherm, while the average price for that same gas would be $3.25 to $3.28 per decatherm. The staff believes that the beneficial effects of average cost sequencing on PG&E's other major suppliers far outweigh the effect of this relatively higher sequencing price. Staff points out that of the total gas available to PG&E, only 6.6% falls into the California discretionary supply category that would be allowed a higher sequencing price under the staff proposal. On the other hand, more than 83% of available supplies would be exposed to the considerable competitive pressure created by average cost sequencing.

For sequencing similar price gas, the staff recommends employment of a "window concept" to compare prices. Staff states the window concept helps compensate for the uncertainty inherent in estimating gas costs. Within a certain small range, supplies would be sequenced on a pro-rata basis as if they had the same average or avoidable costs. (A small differences in gas prices, perhaps only 0.1 to 0.001 of a cent per decatherm could mean enormous differences in the volume of sales taken from a given supplier.) The staff believes that this small difference would place too much weight on the accuracy of the gas price calculations and in fact believes that small errors in estimating gas costs or gas sales could have a dramatic effect on sales levels. It, therefore, advocates a window size of 5¢ per decatherm as sufficiently large to accommodate errors in cost and sales estimations and simultaneously promote supplier competition. A larger window would provide too large a "comfort zone" for suppliers and thereby greatly reduce competitive pressure. This is especially true as wellhead prices are decreasing and California suppliers' costs are converging into a narrower range.

The question of an appropriate sequencing of prices for GEDA gas was raised in the spring GAC, and again in PG&E's most recent reasonableness review. The staff states it considered the circumstances surrounding this issue and continues to agree with PG&E that the sunk costs associated with GEDA gas need to be considered when determining the placement of discretionary California GEDA gas. The staff is very concerned however that PG&E pay only competitive prices to its GEDA subsidiary and to those third-party producers involved in GEDA projects. The staff argues that unduly high GEDA prices cost the ratepayers extra money on all GEDA wells, not just those shared by third-party producers. It considers the question of GEDA sequencing to be a reasonableness issue and plans to address during PG&E's next reasonableness review whether PG&E has paid unreasonably high prices for GEDA gas, particularly in light of the recent decline in natural gas prices.

El Paso

El Paso states that from the completion of the initial El Paso pipeline to California in 1947 until about two years ago, the California distributors were ready, willing, and able to receive all of the gas which El Paso could deliver through its pipeline and that until very recently the distributors were supplying forecasts which indicated that they needed all of the gas which El Paso could purchase and move to the California border up to the full capacity of its system. It states that beginning in about April 1982, however, the distributors began to refuse substantial quantities of available El Paso gas, a situation which continues and is now projected to continue for the reasonably foreseeable future. The 1984 California Gas Report shows that PG&E's purchases from El Paso fell from an average of 1,107 MMcf/d in 1981, to 836 MMcf/d in 1982, to 590 MMcf/d in 1983. Over the same three years, SoCal's purchases fell from an average of 1,625 MMcf/d, to 1,456 MMcf/d, to 1,343 MMcf/d.

El Paso states these sales were not lost because the price was too high because during the entire period El Paso's prices were substantially less than the prices of other out-of-state supplies available to the California distributors, but because the distributors cut back their purchases from El Paso in order to balance their purchases from all sources with a much-reduced level of retail gas demand, while otherwise meeting their take-or-pay and minimum physical take obligations to their other suppliers. El Paso alleges it became the "swing supplier" to California and as a consequence, it and its producer-suppliers have borne the brunt of the precipitous decline in total end-use demand in California; and further, because the Commission utilized a "value-of-service" (as opposed to a cost-of-service) approach to the setting of retail industrial gas rates, there was no connection between the price of El Paso gas and the level of end-use demand in California. El Paso states it found itself in a position where it had absolutely no hope of recovering its lost sales by reducing its price. "Gas vs. gas" competition was foreclosed by the distributors' contractual obligations to other suppliers, "gas vs. oil" competition, by this Commission's "value-of-service" retail industrial rate design philosophy.

El Paso supports PG&E's proposal. El Paso states that it considered the totality of PG&E's proposal, including most critically PG&E's new Canadian import arrangements, its sequencing proposal, its proposal with respect to how the savings in purchased gas costs achieved through the new import arrangements, and through El Paso's own recent PGA rate reduction will be reflected in retail sales rates, the "bottom line" is balanced, fair, and equitable, and is something El Paso could live with and support.

El Paso states PG&E's "equitable purchase policy" is fair and will be perceived as fair by El Paso's producer-suppliers. The contractual preference heretofore given Canadian gas is eliminated. Moreover, differences between suppliers in terms of tariff form and rate design will have far less influence on the sequencing decision than is the case under "incremental" or "avoidable" cost sequencing. It states average cost sequencing rewards the supplier for controlling all elements of cost, not just those costs which are reflected in its commodity rate. Thus, El Paso's efforts to reduce its own operation and maintenance (O&M) and other pipeline expenses will enhance its ability to compete under average cost sequencing and they would not under incremental cost sequencing.

In supporting PG&E's "equitable purchase policy" El Paso states that in light of the apparently unfavorable reaction to the "equitable purchase policy" among Canadian producers, it is vital that this Commission in its decision strongly support PG&E, particularly if the Commission is otherwise prepared to accept in the SoCal CAM the much less favorable terms of the recently renegotiated Western Leg ANGTS Prebuild import project contracts. Otherwise, it argues, Commission approval of the new Prebuild project terms might be seen as undercutting PG&E's own negotiating position as it seeks to secure Canadian producer acceptance of its "equitable purchase policy".

With respect to the staff's window approach for sequencing similarly priced gas, El Paso supports PG&E's nonformulistic approach as preferable, notwithstanding the large degree of discretion which it appears to vest in the distributor. It states that with both this Commission and its suppliers peering intently over its shoulder, the distributor will not exercise such discretion in an arbitrary or unreasoned manner, and will give full consideration to the foreseeable consequences of its decision.

El Paso states that if some sort of formulistic approach is to be adopted, the alternative 15¢ "window" proposed by SoCal in its pending CAM application should be adopted. It argues that the problem with the staff proposal is that very small changes in the average prices of two competing suppliers can cause very large changes in their relative market shares.

<u>California Gas Producers Association</u>

It is the position of Gas Producers that:

1. PG&E's California natural gas deliveries should be sequenced for purchase based on the comparative overall delivered cost of PGT Canadian and El Paso out-of-state natural gas deliveries, and

2. The "accounting price" on which PG&E's affiliated purchases of California gas from Natural Gas Corporation should be used for sequencing PG&E's purchases of GEDA natural gas supplies.

It states these policies are required in order to carry out the intent of the California Gas Policy Act "to encourage, as a first priority, the increased production of gas in this state" in view of the importance of California gas production as part of the state's gas supply, and in view of the fact that California gas is produced and made available by California businesses and California taxpayers employing California workers.

For GEDA gas, Gas Producers recommends the following revision in the proposed sequencing policy:

1. To permit California-produced gas supplies to be produced and sold in fair competition with out-of-state El Paso and PGT Canadian gas supplies, and

2. To terminate PG&E's present discriminatory practice in preferentially purchasing affiliated supplies of California-produced GEDA gas.

It states this can be carried out very simply by requiring that the "accounting price" (currently about $3.80/MMBtu) on which PG&E's purchases of California gas from its 100%-owned natural gas corporation gas exploration and development affiliate also be used for "sequencing" PG&E's purchases of GEDA gas supplies.

Gas Producers argues that the unfair feature of the current PG&E GEDA program is PG&E's sequencing of its affiliated purchases of California GEDA gas at 100% load factor - while purchasing similarly priced, independently produced California gas supplies at a much lower 33%-66% load factor level.

TURN

TURN agrees with PG&E that under present conditions average cost is superior to avoidable cost for sequencing El Paso and PGT gas. TURN cautions that should the average cost, which results in an increase be adopted in the short-term, it must be reexamined.

For California source gas, TURN proposes that California gas be sequenced in relation to the average costs of PGT and El Paso at the California border. It states that for PGT this would be the commodity cost at the international border plus compressor fuel costs across the PGT system. For El Paso gas it would be the average cost of gas sold which includes compressor fuel to the California border. California produced gas priced below the El Paso and PGT average cost would be taken in the "Economic Calgas" category ahead of discretionary El Paso and Canadian supplies. TURN states that more expensive California gas taken after El Paso and PGT would create the lowest price for consumers.

TURN states that should its proposal be rejected, it supports PG&E's proposal as the best alternative.

Tenneco Oil Company and
Conoco, Inc. (Tenneco-Conoco)

Tenneco-Conoco are producer-suppliers of El Paso as well as major royalty owners with respect to gas produced by El Paso and sold in the California Market. Tenneco-Conoco states El Paso has historically provided the lowest cost interstate supply of gas, on a total average cost basis, to PG&E. It states that artificial barriers have prevented a sequencing approach that recognizes or encourages El Paso's competitive position. Its interest is the establishment of a gas sequencing policy that assures El Paso a continued market for its gas and provides an incentive for El Paso to increase its supplies of available domestically produced gas.

Tenneco-Conoco's specific concerns of PG&E's gas purchasing policies and its proposed sequencing policy are: first, the potential exists for uncertainty in the price of Canadian gas. It is alleged that the delivered cost of Canadian gas has been uncompetitive historically, and the proposed demand-commodity rate in the renegotiated contract between PGT and Alberta & Southern Gas Company (A&S) may or may not become effective and in any event is subject to change; second, PG&E proposes to take nearly 100% of discretionary Rocky Mountain gas produced by its affiliate Natural Gas Corporation of California (NGC) prior to any discretionary El Paso gas, despite an average delivered cost for Rocky Mountain gas that is nearly 40¢/Mcf higher than the cost of El Paso gas.

Third, El Paso has made significant efforts to maintain a competitive position in the PG&E market. Specifically, El Paso has filed for a gas price reduction of $0.11 per MMBtu in its most recent purchased gas cost adjustment (PGA) case and has negotiated a reduction in its minimum bill. Despite El Paso's aggressive efforts to reduce its gas costs and corresponding concessions by its producer-suppliers, under the proposed sequencing policy El Paso's gas will be taken at a reduced level in order for PG&E to take more gas from its pipeline affiliate PGT and all the Rocky Mountain gas from its producer affiliate NGC.

Tenneco-Conoco agrees that sequencing various supplies of gas on an average cost basis, taking into account all fixed and variable costs of delivering gas to PG&E, constitutes a sound proposal and generally agrees with the staff that an average cost sequencing approach allows the market to react, on a short- and long-term basis, to competitive factors.

Tenneco-Conoco disagrees with the 5¢ "window" proposed by the staff for use in the sequencing scheme. It argues such a slight window has the potential for disrupting the pipelines' ability to supply equivalent volumes of gas, based upon minor differences in their average gas cost. It, however, would favor the use of a broader window on the basis that the price of Canadian gas is uncertain at this time and could increase even to the maximum border price of $4.94 per MMBtu authorized by the Economic Regulatory Administration (ERA). In this event, it would not be fair to the customers of PG&E or to the suppliers of El Paso to sequence El Paso and Canadian gas on a percentage equivalency basis without the benefit of a window of some nature.

Tenneco-Conoco opposes PG&E's plan to sequence discretionary Rocky Mountain gas at the level proposed. It argues that the preference afforded discretionary Rocky Mountain gas is inconsistent with both an average cost sequencing approach and an effort by PG&E to send signals to producers to reduce their prices in order to enhance sales levels. Without regard to the customers' cost of service credits that result under the GEDA program, it is inescapable that the average delivered cost of Rocky Mountain gas is $4.025 per decatherm, nearly 40¢ higher than the El Paso average delivered gas cost. Preferential takes of high cost Rocky Mountain gas are at the expense of less costly El Paso volumes.

Tenneco-Conoco states that the gas sequencing proposal adopted by the PUC should send signals to both the pipelines and their producer-suppliers that reductions in gas costs will be rewarded with increased gas sales. They object to the fact that through the sequencing proposal a reduction in El Paso's average cost of gas, brought about in large part by price concessions on the part of producers, could result in a reduction, not an increase, in El Paso's sales to PG&E.

Capitol Oil Corporation

Capitol Oil Corporation (Capitol) recommends that avoided cost gas sequencing be discarded because it has been inequitable in the sequencing of northern California gas in relation to other PG&E supplies. It states that avoided cost sequencing has been used as a tool to artificially suppress the price California producers would otherwise receive from their production if allowed to compete on the same basis with other fuels.

Capitol states that the advantages of average cost sequencing are not limited to comparing Canadian and El Paso source gas. Sequencing California gas on average cost can have additional long-term benefits for ratepayers.

Capitol states that if allowed to compete on a total cost basis, California producers of non-GEDA gas would have to beat the price of Canadian and El Paso gas or not survive and that take-levels of California gas would be tested by the market.

Further, even under current avoided cost sequencing, on an "apples and apples" total cost comparison, independently produced non-GEDA northern California gas is less expensive than either Canadian or El Paso source gas. Average cost sequencing, by more closely looking at competing sources of gas on a total cost basis, will allow California producers to prove this point.

Borax

Borax states that whatever sequencing approach is adopted the goal should be to take advantage of the unique opportunity to acquire and maintain Canadian gas at a reduced price. In order to accomplish this the sequencing policy must not result in the artificial switching of load from one supplier to another. Borax asserts that the critical need is for increased overall system load such that gas producers and pipeline companies will be competing for a new market rather than simply negotiating against themselves.

Discussion

This proceeding produced an unprecedented number of participants with interests from producer to burner-tip customers. Predictably each supported a position reflecting their particular pecuniary interest. However, there was almost unanimous agreement that for sequencing of PG&E's gas purchases from El Paso and PGT, average cost, rather than avoided or incremental cost, provides distinct advantages.

The parties are in agreement that average cost sequencing encourages gas suppliers to minimize all costs, both fixed and operational, as well as the cost of gas. It creates an incentive for producers to keep their commodity prices low. By contrast avoided cost sequencing encourages pipeline suppliers to "front-load" their fixed costs into demand charges which are removed from the cost of gas for sequencing purposes since they are considered unavoidable.

We agree that average cost sequencing is well suited to the characteristics of the PG&E system which receives the bulk of its gas from two large transmission pipelines which are comparable in size, well depreciated, and have the ability to compete with each other. By contrast, SoCal suppliers El Paso and Transwestern Pipeline Company compete with newer and smaller pipelines such as PITCO, an affiliate of SoCal bringing gas from Canada through the prebuilt portion of ANGTS and POPCO.

We believe the average cost approach for El Paso and Canadian gas, even at varying load factors, will result in a percentage equivalency basis advocated by the parties. Such an approach will also keep each supplier in a strong competitive position and eliminate the need for the Account 191 adjustment.

In calculating average sequencing cost we believe the staff's recommended 75% of contract quantity is reasonable. The use of this percentage reflects the approximate design sales volume embedded in El Paso's commodity rate. In addition, a much higher proportion of the total costs associated with delivering Canadian Gas to the California border are assigned to the demand charge than is the case with El Paso. However, if El Paso's design sales volumes change this issue should be reviewed.

With respect to sequencing California gas, we agree with the staff and Gas Producers that consistency requires the use of average cost. At this time we will adopt staff's proxy gathering cost of $0.34 per MMBTU, based on the El Paso system, however, we direct PG&E to present a calculation of the comparable cost for its own gathering system in the spring GAC proceeding. We recognize that an average cost approach may lead to slightly higher prices for sequencing of this gas but such costs are offset by the beneficial effects. Such an approach is consistent with economic theory and will stimulate competition. In addition, we feel that the spirit, if not the letter, of the California Gas Policy Act requires us to use the same economic test in sequencing California gas as will be used to compare the cost of gas from PG&E's other two major suppliers.

Tenneco-Conoco and Gas Producers both oppose PG&E's current method of sequencing GEDA gas arguing the correct price should be the accounting price. PG&E and staff take the position that the current use of avoided cost pricing is appropriate. They point out that under the GEDA ratemaking mechanism, the ratepayers bear the sunk costs of exploration and development of the GEDA reserves and that the program is credited with any revenues attributable to sale of the gas in excess of the cost of producing the gas. Once the avoided costs associated with producing the gas are met, the remainder of the accounting price is credited back to the GEDA program. Thus, the avoidable costs of taking the GEDA gas is less than the accounting price. Using the accounting price for sequencing purposes would fail to recognize the actual incremental cost for GEDA gas. We agree with PG&E and staff that GEDA gas should be sequenced based on its incremental price.

All of the parties who addressed the sequencing issue opposed staff's recommended "window concept" on the basis that it imposes an inflexible formula for determining the competitiveness of gas supply prices and assigning sequencing positions. It is also argued that the staff's proposed .5¢ per therm window is so small that estimating errors could easily have an adverse effect on the particular supplier.

We believe that the staff approach has merit. While the staff proposal of .5¢ per therm is rather small, a larger window could provide too large a comfort zone for suppliers thus reducing the competitive pressure. At 75% of contract quantity the average costs for El Paso and PGT are \$3.6174 and \$3.5952 per Dth, respectively. Consequently, a 1.0¢ window allows discretionary El Paso gas and discretionary California gas, with an average cost up to \$3.6952 per Dth, to be sequenced on a percentage equivalency basis. Using the staff's suggested gathering cost estimate of \$0.34 per Dth, the price paid to California producers for percentage equivalency sequencing could be no higher than \$3.3552 per Dth. For a 100% load factor California producers would have to break the window. That is the average cost could be no higher than \$3.4952 per Dth with a wellhead price no higher than \$3.1552 per Dth. Accordingly, we will adopt the staff recommendation but will establish a window of 1.0¢ per therm for sequencing similarly priced gas.

<u>Rate Design</u>

Gas rate design guidelines were established in PG&E's general rate case for test year 1984 in D.83-12-068 and D.83-12-069, dated December 22, 1983 and D.84-04-015, dated April 4, 1984 in PG&E's October 1983 GAC. The guidelines result in a design which follows:

1. Adopts a sales profile, marginal cost (alternate fuel oil price), marginal operating cost (swing fuel), revenue requirement, and system average rate (SAR).
2. Calculates resale rates and associated revenue requirement.
3. Calculates the indexed rates and revenue requirement (G-50, G-58, and G-59).
4. Sets the G-55 and G-57 rates at PG&E's contract fuel oil price, exclusive of the ammonia surcharge.
5. Increases (or decreases) residential and commercial rates by equal percentages until the revenue requirement is reached.
6. Sets Tier I of the residential rate at 85% of the SAR.

With the problems associated with fuel switching by large customers, the Commission also adopted a number of innovations in industrial rates, which include:

Schedule G-50 (industrial rate for customers who have alternative fuels):

a. Interim October 1983 GAC (D.83-12-069, December 22, 1983) established a two-tier (versus one-tier) G-50 with Tier II applicable to usage in excess of 100,000 therms per month. G-50 is to be indexed to changes in #2 fuel oil.

b. Final October 1983 GAC (D.84-04-015, April 4, 1984) established a three-tier (versus two-tier) G-50 with Tier II applicable to usage in excess of 100,000 therms per month and Tier III applicable to usage in excess of 1,600,000 therms per month. Tiers I and II are indexed to #2 fuel oil and Tier III is set equal to G-58 schedule. Edison's Cool Water Units 3 and 4 are excluded from eligibility for Tier III since these units cannot be converted to use #6 fuel oil; also, increased sales at Cool Water would displace purchases from SoCal under its GN-5 rate.

Schedule G-58 (industrial rate schedule for customers with an alternative fuel of #6 fuel oil):

D.83-06-004 (June 1, 1983) established G-58 on an experimental basis to mitigate fuel switching by large industrial customers. PG&E was directed to report on the effect of G-58 on G-50 customers.

Schedules G-80, G-82, and G-84 (incentive rates for potential fuel switchers):

a. D.84-08-116 (August 7, 1984) established a new G-80 schedule with rates equal to the G-58 price per therm. The G-80 rate is applicable to incremental sales in excess of 100,000 therms per month.

b. D.84-08-116 established Schedule G-82 that has an auction rate applicable to incremental natural gas usage by nonresidential customers.

c. D.84-08-116 established Schedule G-84 a contract rate applicable to incremental natural gas usage of a minimum of 50,000 therms per month negotiated between PG&E and nonresidential customers. The minimum price would be the NGPA alternative fuel cost for nonexempt boiler fuel customers.

d. D.84-08-116 established Schedule G-86 food processor rate for incremental sales. This was adopted in conjunction with SoCal GN-6 rate of 44¢/therm.

The G-80 schedules apply to incremental sales. In D.84-08-116, we adopted staff's definition of incremental sales which were defined as:

a. First contract year: Adjusted for the number of days in the current billing month, the amount by which use during the current billing month exceeds the base use (sales for same period 12 months prior).

b. Succeeding contract year: Incremental natural gas as defined in (a) above, plus 20% of incremental natural gas use during the corresponding billing month one year prior, adjusted for the number of days in the current billing month.

PG&E's Rate Design

PG&E is proposing rate decreases to all customer classes by allocating its proposed net revenue decrease of $131 million ($200.9 million GAC decrease, plus increases of $49.3 million for attrition and $20.3 million for LNG costs) among all classes. PG&E proposes to distribute one-third of the net decrease to residential and commercial customers, on the basis of an equal percentage decrease, with two-thirds of the decrease allocated to the industrial class. PG&E states that while its proposal modifies current Commission guidelines in setting rate levels, it is in keeping with the intent to minimize fuel switching of all customers while moderating the rate impact to high priority customers.

The following table shows PG&E's present rates and revenues and the proposed decrease in revenues.

Table IV

SUMMARY OF RATES AND REVENUES(1)
12 MONTHS BEGINNING 10/1/84

LINE NO	CLASS OF SERVICE AND SCHEDULE	ADJUSTED SALES(2) (MTH)	PRESENT RATES EFFECTIVE 8/12/84 ($/TH)	PRESENT RATES EFFECTIVE 8/12/84 (M$)	PROPOSED DECREASE ($/TH)	PROPOSED DECREASE (M$)	PROPOSED DECREASE (%)	PROPOSED RATES ($/TH)	PROPOSED RATES (M$)	LINE NO.
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
	RESIDENTIAL									
1	TIER I	1,371,181	.47432	650,392	-.01610	-22,082	-3.4	.45822	628,311	1
2	TIER II	603,827	.74661	450,823	.00000	0		.74661	450,823	2
3	SS,GT ADJUSTMENT			-5,708					-5,708	3
4	TOTAL RESIDENTIAL	1,975,008	.55469	1,095,508	-.01118	-22,082	-2.0	.54350	1,073,426	4
	COMMERCIAL									
5	EXISTING G-2(3)	1,206,710	.66168	798,456	.00000	0		.66168	798,456	5
6	INCENTIVE RATE (4)		.66168			-16,106		-	-16,106	6
7	TOTAL COMMERCIAL	1,206,710	.66168	798,456	-.01335	-16,106	-2.0	.64833	782,350	7
	INDUSTRIAL AND STEAM ELECTRIC									
8	G-50(5) TIER I	304,384	.53903	164,090	-.04603	-14,020	-8.5	.49300	150,160	8
9	TIER II	343,497	.51071	175,529	-.06471	-22,241	-12.7	.44600	153,289	9
10	TIER III	106,229	.47572	50,535	-.08572	-9,106	-18.0	.39000	41,429	10
	TOTAL	754,110		390,154					344,854	
11	G-55A (6)	82,720	.50189	41,517	-.06987	-5,794	-13.9	.43202	35,823	11
12	G-55	2,941,440	.54050	1,589,967	.00000	0	.0	.54050	1,589,967	12
13	G-57	17,280	.54050	9,340	.00000	0	.0	.54050	9,340	13
14	G-58	352,340	.47572	167,615	-.08572	-30,203	-18.0	.39000	137,412	14
15	G-59	227,020	.38000	82,468	.00000	0	.0	.38000	82,468	15
16	G-80,G-82,G-84	142,140	.45000	61,120	.00000	0	.0	.45000	61,120	16
17	TOTAL INDUSTRIAL AND STEAM ELECTRIC	4,507,870	.52196	2,342,347	-.01805	-81,363	[illegible]	.50154	2,260,983	17
18	TOTAL COMMERCIAL INDUST./STEAM ELEC.	5,714,580	.54961	3,140,803	-.01706	-97,469	[illegible]	.53256	3,043,334	18
	RESALE									
19	G-60	35,800	.42844	15,338	-.03163	-1,132	-7.4	.39681	14,206	19
20	G-61	1,800	.42829	771	-.03163	-57	-7.4	.39676	714	20
21	G-62	710	.42829	304	-.03163	-22	-7.4	.39666	282	21
22	G-63	45,860	.42829	19,641	-.03163	-1,451	-7.4	.39666	18,191	22
23	TOTAL RESALE	84,170	.42836	36,055	-.03163	-2,662	-7.4	.39673	33,392	23
24	TOTAL	7,773,758	.54939	4,272,366	-.01572	-122,214	-2.9	.53337	4,150,152	24

FOOTNOTES:

(1) EXCLUDING OTHER OPERATING REVENUE
(2) ADJUSTED FOR G-10 SALES OF 1,333 MTH
(3) INCLUDING INTERDEPARTMENTAL CONSTRUCTION CLEARING AND OTHER OPERATIONS SALES
(4) COMMERCIAL DECREASE ALLOCATED TO COMMERCIAL INCENTIVE RATE.
(5) INCLUDING INTERDEPARTMENTAL STEAM HEAT & SCE COMBINED CYCLE
(6) BECAUSE THE G-55 RATE IS NOW HIGHER THAN THE G-50 RATE, A COGENERATOR MAY BE BILLED UNDER SCHEDULES NOS. G-50 OR G-58 IF APPLICABLE. AN AVERAGE COGENERATOR RATE OF $.50189/THERM IS SHOWN FOR SCHEDULE NO. G-55A WITH COGENERATOR SALES BILLED AS FOLLOWS: G-50: 30,040 (MTH), G-58: 2,380 (MTH)
(7) ADJUSTMENT FOR PUC FEE REVENUES. SEE FOOTNOTE (5) ON TABLE II OF THIS SECTION.

The mechanics of PG&E's proposed rates are as follows:

a. Resale Rates

The rates charged to PG&E's resale customers, the City of Palo Alto (Schedule G-60), the City of Coalinga (Schedule G-61), C. P. National Corporation (Schedule G-62), and Southwest Gas Corporation (Schedule G-63), were calculated using the Commission's method described in D.84-08-116 and are based on four components: (1) the average cost of purchased gas, (2) franchise fees and uncollectibles accounts expense, (3) a contribution to gas margin, and (4) GEDA. In addition, the ammonia surcharge is applicable to the City of Palo Alto and the City of Coalinga. The rates reflect the updated average purchase gas costs over the GAC forecast period, and result in a decrease to this customer class of about $2.7 million.

Although using the method outlined in D.84-08-116, PG&E recommends further investigation into setting resale rates.

b. Commercial Rate: Schedule G-2

PG&E is exploring whether or not rate design changes would be warranted in order to mitigate further sales loss on this schedule. Any such changes would be proposed by PG&E at a later time.

PG&E states it has become apparent that commercial gas service is not immune to competition from other resources, even though these customers do not normally have alternate fuel capability in the manner required for lower priority services. Therefore, one or more new schedules may be proposed to meet this competition, particularly with respect to larger loads. For the purpose of this proposal, the decrease allocated to the commercial class would be applied to such new schedules.

c. Industrial and Steam Electric Rates.

(1) Schedule G-50

Schedule G-50 is a three-tier indexed rate. The first two tiers are indexed to changes in the price of #2 fuel oil. The third-tier is set equal to the Schedule G-58 rate, which is indexed to changes in the price of #6 fuel oil. PG&E proposes to reduce the current rate level in each tier. Thus, the first tier is set at $0.49300 per therm, the second tier is set at $0.44600 per therm, and the third tier set at $0.39000 per therm. This will result in a total decrease to the G-50 customers of approximately $45.4 million. PG&E proposes to continue the established indexing mechanism at the new rate levels introduced in this rate proposal.

(2) Schedule G-58

Schedule G-58 rate is indexed to changes in the average price of #6 fuel oil, as posted in Platt's Oilgram. PG&E proposes to reduce the current level from $0.47572 per therm to $0.39000 per therm (18%), representing a decrease of $0.08572 per therm, or $30.2 million. As in Schedule G-50, PG&E proposes to continue the indexing mechanism established by the tariff, starting with the new rate level proposed in this case.

(3) Schedule G-59

The October 1984 minimum bid price was set at $0.38000 per therm based on (1) the anticipated gas-supply sources required to serve the load for the month; (2) the price of alternate fuels to potential Schedule G-59 customers, and (3) the cost of transporting gas. Under the provisions of this tariff, the bid price may vary over the GAC test period. The Schedule G-59 rate is shown at $0.38000 per therm for illustrative purposes in this proposal; however, given the expected lower gas costs during the test period, it is likely that the minimum bid prices will be lower.

(4) Schedules G-55 and G-57

The rates for Schedules G-55 and G-57 are set at the current rate of $0.54050 per therm. In recent decisions, these rates have been maintained at current levels. There have been no developments which would justify a change at this time.

(5) Schedule G-55A

The commodity charge for service under this schedule is the lesser of the Schedule G-55 commodity rate (currently $0.54050 per therm) or any otherwise applicable natural gas rate schedule. Under PG&E's existing gas rate schedules, a cogenerator may be billed under: (1) Schedule G-58 if it has #6 fuel oil as its exclusive alternate fuel and is willing to accept the lower priority, (2) Schedule G-50, or (3) Schedules G-80, G-82, or G-84 for incremental usage.

Schedule G-50 rate is currently lower than the Schedule G-55 rate. Thus, a cogenerator would be billed at the lesser commodity rate of Schedule G-50 according to the G-55A tariff. Under these circumstances, PG&E adjusted revenues under present rates to reflect forecasted cogeneration sales under both Schedules G-50 and G-58. The Schedule G-55A rate was set at an average rate of $0.43202 per therm for purposes of this rate proposal, which reflects the proposed rate reduction in the G-50 and G-58 rates. This results in a decrease of about $5.8 million.

(6) New Incremental Gas Sales Rates

In the most recent GAC decision (No. 84-08-116) three new industrial gas rates were adopted, Schedules G-80, G-82, and G-84. It is difficult to determine at this time which incremental sales rate would be more attractive to industrial customers. In PG&E's gas rate design, a rate of $0.43000 per therm was assumed for these incremental sales rates. However, given the expected reduction in gas costs, the actual rates under one or more of these schedules may be lower.

The Commission in D.84-08-116 also established a temporary rate for food processors who operate in areas where high sulfur fuel oil (greater than 0.5% sulfur) may be burned. This rate, filed as Schedule G-86, expires November 30, 1984, and is applicable to "incremental sales" only, as defined for Schedules G-80, G-82, and G-84. Since this rate is experimental and available for only two months of the GAC forecast period, it is not shown in the rate proposal.

d. High Priority Rates

In order to signal the current and pending reduction in supplier gas prices to the high priority customers, the average residential (Schedule G-1) and commercial rates were decreased by equal percentages until the revenue requirement was reached. After the residential average rate was determined, the Tier I residential rate was set slightly above 85% of the system average rate to ensure that no residential customer would realize an increase in rates. This resulted in a decrease to the residential class of approximately $22.1 million, and a decrease to the commercial class of about $76.1 million.

The following tables show PG&E's and staff's recommended rate design with and without the attrition allowance and LNG adjustment requested by PG&E.

Includes Attrition and LNG offsets

Table V

COMPARISON OF PGandE AND STAFF PROPOSED RATES AND REVENUES AND PROPOSED DECREASE IN REVENUES

SCENARIO 1

	PGandE Proposed Rates and Revenues M$	PGandE Proposed Rates and Revenues $/therm	PGandE Proposed Decrease in Revenues M$	PGandE Proposed Decrease in Revenues %	Staff Proposed Rates and Revenues M$	Staff Proposed Rates and Revenues $/therm	Staff Proposed Decrease in Revenues M$	Staff Proposed Decrease in Revenues %
RESIDENTIAL								
Tier I	684,773	.45621	-27,199	-3.8	680,211	.45327	-31,761	-4.5
Tier II	389,244	.82118	0	0	389,244	.82119	0	0
GS, GT, ADJ.1/	-5,708							
Total Residential	1,368,309	.54091	-27,199	-2.5	1,069,455	.54149	-31,761	-2.9
COMMERCIAL								
Tier I (G-2A)	719,892	.65827	-3,729	-.5	627,140	.66168	0	0
Tier II (G-2B)2/	58,729	.51927	-16,106	-21.5	163,398	.63110	-7,917	-4.6
Total Commercial	778,621	.64524	-19,835	-2.5	790,538	.65522	-7,917	-1.0
INDUSTRIAL								
G-50 Tier I	150,160	.49200	-14,020	-8.5	153,404	.50365	-10,775	-6.6
Tier II	153,289	.44600	-22,241	-12.7	163,369	.47533	-12,160	-6.9
Tier III	41,429	.39000	-9,106	-18.0	46,777	.44034	-3,758	-7.4
G-50 Total	344,854	.45706	-45,367	-11.6	363,550	.48184	-26,693	-6.8
G-55A	85,823	.43202	-5,794	-13.9	38,683	.46651	-2,933	-7.0
G-55	1,589,967	.54050	0	0	1,548,107	.52627	-41,860	-2.6
G-57	9,340	.54050	0	0	9,094	.52627	-245	[illegible]
G-58	137,413	.39000	-30,203	-18.0	155,149	.44034	-12,466	[illegible]
G-59	82,468	.38000	0	0	92,652	.38000	0	
G-80, G-82, G-84	61,620	.43000	0	0	61,120	.43000	0	
Total Industrial	2,260,365	.50156	-81,363	-3.5	2,268,155	.50320	-84,197	-4.7
RESALE3/								
G-60	14,259	.39829	-1,079	-7.0	14,171	.39585	-1,167	-7.6
G-61	717	.39824	-54	-7.0	712	.39563	-59	-7.7
G-62	283	.39814	-21	-7.0	18,406	.39524	-1,539	-7.7
G-63	18,259	.39814	-1,383	-7.0				-7.7
Total Resale	33,527	.39821	-2,538	-7.0	33,285	.39550	-2,765	-7.7
GS, GT1/					-5,708			
Total Net					4,155,923			-3.0
Other Revenues					3,600			
Total (Gross)	4,141,430	.53274	-130,925	-3.1	4,159,528	.53507	-126,642	-3.0

1/ PGandE includes GS-GT as an adjustment to residential revenues, while the Staff includes it as an adjustment to total revenues.

2/ PGandE proposes a two-tiered commercial schedule (2nd tier applicable to customer usage over 25,000 therms/month), while Staff proposes a separate G-2B rate schedule applicable to commercial customers able to burn propane as their alternate fuel.

3/ PGandE shows G-62 and G-63 separately, while Staff combines them.

Excludes Attrition and LNG Offsets

Table VI

COMPARISON OF PGandE AND STAFF
PROPOSED RATES AND REVENUES
AND PROPOSED DECREASE IN REVENUES

SCENARIO 2

	PGandE				Staff			
	Proposed Rates and Revenues		Proposed Decrease in Revenues		Proposed Rates and Revenues		Proposed Decrease in Revenues	
	M$	$/therm	M$	%	M$	$/therm	M$	%
RESIDENTIAL								
Tier I	668,200	.44510	-43,875	-6.2	668,758	.44554	-43,224	-6.2
Tier II	365,547	.77119	-23,695	-6.1	389,244	.82119	0	
GS, GT, ADJ.1/	-5,708							
Total Residential	1,027,938	.52047	-67,570	-6.2	1,058,002	.53569	-43,224	-3.9
COMMERCIAL								
Tier I (G-2A)2/	690,468	.63127	-33,153	-4.6	627,140	.66163	0	
Tier II (G-2B)	58,729	.51927	-16,106	-21.5	163,398	.63110	-7,917	-4.6
Total Commercial	749,197	.62086	-49,259	-6.2	790,538	.65512	-7,917	-1.0
INDUSTRIAL								
G-50 Tier I	150,160	.49300	-14,020	-8.5	145,911	.47905	-18,268	-11.1
Tier II	153,289	.44600	-22,241	-12.7	154,915	.45073	-20,614	-11.7
Tier III	41,429	.39000	-9,106	-18.0	44,164	.41574	-6,371	-12.6
G-50 Total	344,854	.45706	-45,367	-11.6	344,990	.45724	-45,253	-11.6
G-55A	35,823	.43202	-5,794	-13.9	36,643	.44191	-4,973	-11.9
G-55	1,589,967	.54050	0	0	1,519,014	.51638	-70,953	-4.5
G-57	9,340	.54050	0	0	8,923	.51638	-416	-4.5
G-58	137,413	.39000	-30,203	-18.0	146,482	.41574	-21,133	-12.6
G-59	82,468	.38000	0	0	92,652	.38000	0	
G-80, G-82, G-84	61,120	.43000	0	0	61,120	.43000	0	
Total Industrial	2,260,985	.50156	-81,363	-3.5	2,209,824	.49022	-142,728	-8.0
RESALE3/								
G-60	14,166	.39569	-1,172	-7.6	14,157	.39546	-1,181	-7.7
G-61	722	.39564	-59	-7.6	721	.39524	-60	-7.8
G-62	281	.39554	-23	-7.6	18,388	.39485	-1,557	-7.8
G-63	18,129	.30554	-1,502	-7.6				
Total Resale	33,298	.39561	-2,757	-7.6	33,256	.39521	-2,798	-7.8
GS, GT1/					-5,708			
Total Net					4,085,913	.52372		
Other Revenues					3,600			
Total (Gross)	4,071,427	.52374	-200,950	-4.7	4,089,513	.52427	-196,656	-4.6

1/ PGandE includes GS-GT as an adjustment to residential revenues, while the Staff includes it as an adjustment to total revenues.

2/ PGandE proposes a two-tiered commercial schedule (2nd tier applicable to customer usage over 25,000 therms/month), while Staff proposes a separate G-2B rate schedule applicable to commercial customers able to burn propane as their alternate fuel.

3/ PGandE shows Nos. G-62 and G-63 separately, while Staff combines them.

Staff

The staff set its proposed rates as follows:

1. The first tier of the residential rates at 85% of the SAR.
2. The second tier of the residential class at the current rate.
3. The G-2 rate at the current rate.
4. The P-2B rate at $0.63110 per therm.
5. The G-50 block rates, G-58, G-59, and the incremental sales rates (G-80, G-82, and G-84) were set at present levels.
6. Resale rates set as the sum of:
   a. The average cost of gas.
   b. Franchise fees.
   c. GEDA adjustment.
   d. Contribution to margin.
   e. Separate balancing account for each resale customer.
   f. Ammonia surcharge for Cities of Palo Alto and Coalinga.

A. Resale Rates

The staff states its methodology for calculating resale rates closely parallels that currently employed in the SoCal CAM proceeding (A.84-09-022). Staff proposes the use of a separate balancing account for each resale customer arguing that it ensures that the individual resale customers carry a reasonable portion of the GCBA. Staff's methodology for resale rates differs from PG&E's methodology by excluding uncollectibles and the inclusion of its proposed separate balancing account. Staff also states the contribution to margin was established in the general rate case and is currently calculated as the current resale rate without the ammonia surcharge less gas cost, franchise and uncollectibles, and the GEDA rate.

B. New Priority 2B Rate

Staff states investigation has shown that industrial gas customers are not the only customers that are able to switch to alternative fuels. Many commercial customers have the ability to burn propane as an alternative to natural gas. If propane prices continue to remain below natural gas prices, many commercial customers may well be willing to invest in the additional equipment necessary to burn propane. Staff states that over the past six months (January to July 1984), the number of P-2B customers has declined by 4.58%. Over the same period Platt's Oilgram reported a drop in propane prices for the San Francisco Bay Area of 6.7% to a July price of $.5681 per therm.

In order to prevent the loss of additional commercial customers to propane, the staff proposes a new Priority 2B schedule and rate for commercial customers able to burn propane. This rate of .63110¢ per therm is equal to the January to July average propane price in the San Francisco Bay Area plus 10%. The 10% addition was included to account for the fact potential propane customers would have to install additional equipment to burn propane.

C. The Food Processor Rate: G-86

In D.84-08-116, the G-86 rate was established as a temporary schedule for food processors. In that decision, the Commission also established Schedule G-80. Both are schedules applicable only to incremental sales. In this proceeding, both PG&E and the staff are recommending that the G-80 schedule and other schedules applicable to food processors be reduced which will result in lower gas rates which for food processors and other industrial customers should be more competitive with alternate fuels. Thus, staff and PG&E recommend that the G-86 schedule not be continued.

D. G-59 (EOR) Sales

The staff recommends that EOR rates by PG&E and SoCal should be set at approximately the same level to recognize that both utilities are in competition for the same customers. Staff states neither PG&E nor SoCal should have a competitive advantage in the uncertified service territory that currently exists in the Bakersfield area. The EOR rate has been based on the marginal cost of gas plus a reasonable contribution to margin. The staff recommends that PG&E's existing rate of 38¢ per therm be adopted as a fixed rate until its next GAC proceeding. Staff also recommends that the existing G-59 schedule should be revised to eliminate bidding and allow for indexing similar to G-58.

E. Calculation of SAR

In line with Commission rate design guidelines, the staff's proposed rate design set the first tier of the residential class of service at 85% of the SAR. An issue arises as to the calculation of the SAR. The staff included an amount of $3,600,000, "other operating revenues", which represent revenues from special contracts and rents, and which reduce the revenue requirement from the general sales tariffs. The components include: Miscellaneous Service and Other Gas Revenue, Transportation Service, PITCO Revenue, and Rents.

The staff's inclusion of this amount raises the SAR slightly over that proposed by PG&E, which did not include these revenues in the SAR calculation.

F. G-55 Rate, Tier II Residential

As a result of the methodology discussed above, the staff-proposed G-55 rate is 51.638¢ per therm. PG&E's proposed rate is 54.050¢, the current rate. The staff rate is a 4.5% decrease from the current rate and consumes $71 million of the GAC decrease.

The Tier II residential rate rose from 74.622¢ to 82.119¢ in the November 7 baseline decision, D.84-11-016. The instant staff proposal uses the 82¢ rate merely because that decision adopted it. However, there is no suggestion in D.84-11-026 that future revenue reductions should not in any part be used to reduce this rate level.

G. Ammonia Surcharge

SoCal requested the staff to review the Ammonia Surcharge Adjustment Clause in the November 1984 CAM proceeding instead of the May 1985 CAM proceeding as originally scheduled. SoCal currently forecasts a total requirement of $11,243,103 (see CAM A.84-09-022) for the November 1984 through October 1985 forecast period. The staff has included in its recommendation an assumed share for PG&E of $4,900,000 for the October 1984 through September 1985 forecast period based on figures submitted in the SoCal CAM which PG&E has not included in its rate design proposal. The staff proposal appears reasonable.

H. El Paso Minimum Bill Credit

The staff did not include any adjustment for minimum bill credit since such reductions are speculative at present. Staff states that in D.84-08-116, A.84-03-07, PG&E's last spring GAC decision, the Commission rejected inclusion of any such estimate because it had not made a final determination regarding the 1984 sales for SoCal.

CMA

CMA supports PG&E's rate design proposal stating it is reasonable in view of the substantial loss of industrial load due to fuel switching and is the only solid proposal with the opportunity to stimulate a significant increase in gas sales.

CMA states the Commission should take full advantage of the opportunity to reduce industrial gas rates to a competitive level.

without raising residential rates or denying PG&E the ability to recover its authorized revenue requirement. It states there is no question that the significant increase in load will result in a broader spread of the company's fixed cost recovery, lower average gas costs on the system, and further induce price reductions from gas producers and suppliers.

Failure to authorize an appropriate reduction in industrial rates will, argues CMA, also lead to even further uneconomic fuel switching, something the Commission is trying to avoid. Further, increased usage by the industrial class will lower the average unit price of gas coming into PG&E's system and broaden the base for fixed cost recovery.

CMA states that to give the high priority customer class the amount of reduction advocated by TURN would be counter-productive by encouraging further fuel switching by low priority customers causing a continuing overall decline in gas sales. The ultimate result would be to require high priority customers to absorb an even higher share of the PG&E system fixed costs.

CLFP

CLFP addressed only those rate schedules affecting its members. It stated that bifurcation of the G-2 rate would have only a modest effect upon alternate fuel investments, that the proposed Tiers I and II G-50 rates will reduce pressure to invest in #6 oil capability in the short run, that the proposed G-58 rate would signal economically available gas to food processors, and that an effective G-58 rate would obviate the need for the G-80 series rates.

TURN

TURN stated it agreed with PG&E and staff that industrial rates must change to reflect variations in the cost of gas and transmit market signals to suppliers. It stated that a strict alternate fuel pricing policy is no longer constructive. However, TURN contends that residential and commercial customers must not be left behind with the high cost burdens that have been imposed upon them in recent years arguing they too should be allowed to share in the rate reductions that are now available.

TURN states that since the spring GAC proceeding (D.84-08-116), PG&E's average cost of gas, defined for the purpose as the "current cost of purchased gas" divided by total sales, has declined from 38.969¢ per therm to 35.691¢, a reduction of about 3.3¢. Under TURN's proposed revenue requirement and rate design, the rate reduction to industrial (and other) customers would be about 4.6¢. TURN states that surely this is a sufficient signal to producers that price concessions on their part will translate into decreased rates and an increased market. It states there are dangers in steeper rate cuts such as the 8.6¢ (18%) reduction in G-58 proposed by PG&E.

TURN states that the sequencing and rate design finally approved will send the appropriate signal to gas producers but that industrial rates should not be lowered so as to eliminate virtually all oil price competition. It argues the potential for further market gains must continue if California hopes to achieve even lower gas prices in the future.

TURN states its rate design proposal is designed to apply both now <u>and</u> in the intermediate-term future--an equal sharing of rate reductions among residential, commercial, and industrial customers. Initially, TURN presented two alternative approaches, equal cents per therm and equal percentage changes. While presenting two approaches TURN recommends adoption of the equal cents per therm method.

The following table shows TURN's recommended rate design.

Table VII

PACIFIC GAS AND ELECTRIC COMPANY

TURN's Proposed Rate Design

Schedule	Sales (Mth)	Present Rates $/th	Present Rates M$	Proposed Decrease M$	Proposed Decrease $/th	Proposed Rates[1] M$	Proposed Rates[1] $/th
Res. TI	1,501,006	.47433	711,972	-44,850	-.02988	667,122	.44445
Tier II	474,002	.82118	389,244	-45,659	-.09632	343,585	.72486
Total	1,975,008	.55758	1,101,216	-90,509	-.04583	1,010,707	.51175
G-2 TI	1,093,611	.66168	723,621	-39,198	-.03584	684,423	.62584
Tier II	113,099	.66168	74,835	-16,106	-.14241	58,729	.51927
Total	1,206,710	.66168	798,456	-55,304	-.04583	743,152	.61585
G-50 TI	304,584	.53903	164,180	-13,959	-.04583	150,221	.49320
Tier II	343,697	.51071	175,529	-15,751	-.04583	159,778	.46488
Tier III	106,229	.47572	50,535	- 4,868	-.04583	45,667	.42989
Total	754,510	.51718	390,221	-34,578	-.04583	355,643	.47135
G-55A	82,920	.50189	41,617	- 3,800	-.04582	37,817	.45607
G-55	2,941,660	.54050	1,589,967	0	.00000	1,589,967	.54050
G-57	17,280	.54050	9,340	0	.00000	9,340	.54050
G-58	352,340	.47572	167,615	-16,148	-.04583	151,467	.42989
G-59	243,820	.38000	92,652	0	.00000	92,652	.38000
G-80's	142,140	.43000	61,120	0	.00000	61,120	.43000
Resale[2]	84,170	.42836	36,055	- 2,766	-.03286	33,289	.39550
Adjust[3]	1,332	--	-5,708	--	--	-5,708	--
	7,801,890	.54891	4,282,550[4]	-203,103[4]	-.02603	4,079,447[4]	.52288

1/ If ammonia surcharge increase is authorized, that amount should be added to each non-residential schedule.

2/ Staff proposed rates shown for illustrative purposes only (Ex. 29, p. 7).

3/ Addition of 1332 Mth reflecting G-10 discount, and subtraction of 5,708 M$ for GS and GT.

4/ Columns do not sum due to rounding.

IMOTEK

Mr. Cottrell, president, testified that it was necessary to retain the present G-55 rate in order that qualified cogenerators using renewable fuels such as biomass materials, wood, etc. could compete with steam electric utilities.

Independent Power Corporation

Independent Power Corporation is concerned with the G-55A rate for cogenerators. It is alleged that PG&E discriminates in applying this rate and if it is not applied fairly the economic benefits of cogeneration projects are undermined.

Because of this alleged pricing discrepancy, PG&E and the staff entered into a stipulation that PG&E's G-55A schedule be modified as follows:

a. "All other applicable rate schedules" should be defined to include, for that portion of the gas that would have been used in the production of thermal energy, those rate schedules otherwise available to the site.

b. A special Condition 7 should be added to the tariff which provides the precise mechanism for measuring gas which would have been used but for the cogeneration process.

With potential administrative problems in implementing the stipulation, PG&E and Independent Power Corporation propose to use standard factors based on currently available information concerning gas turbine cogeneration projects. For simple cycle gas turbine cogeneration projects, the standard factor would make approximately 74% of the gas eligible for G-58. For combined cycle gas turbine cogeneration projects, the standard factor would make approximately 50% of the gas eligible for G-58.

Anheuser-Busch, Inc./Nabisco Brands, Inc. (Anheuser-Nabisco)

Anheuser-Nabisco supports PG&E's rate design stating that it best serves the PG&E objective to strengthen its position in the industrial market to the benefit of all customers. PG&E's proposed rate design will provide a signal to all gas suppliers with the potential to enlarge their market. With the expectation of capturing new markets, increasing sales in existing markets and recovering sales lost to fuel oil, Anheuser-Nabisco states that the price competition among all suppliers should serve to lower PG&E's average acquisition cost of gas supplies as well as providing a broader customer base for fixed cost recovery.

It is also stated that the appropriateness of the rationale proposed by PG&E is also reflected in the position of the Canadian producers and the NEB in approving the A&S application to lower prices, albeit on an interim basis.

Finally, it states only PG&E's rate design proposal provides the substantial reductions in lower priority rates which will secure Canadian gas price concessions and afford to PG&E's other ratepayers the benefits of substantially increased sales.

Borax

Borax supports PG&E's proposed rate design stating that over the past decade there has been an ever-increasing trend toward the loss of industrial gas customers from PG&E's system. It states that during the 1973-83 period, on the order of 66% of PG&E's industrial volume has dropped from the system and that falling oil prices and rapidly increasing gas rates have been responsible for this fuel switching.

Borax states that the industrial customers are the only major elastic group of customers on the PG&E system. Because of this elasticity, once rates are dropped, fuel switchers will respond by returning to the system and abandoning their alternate fuel sources. The return to the system would not only increase the total volume of gas but send a strong encouraging signal to California industry that a climate exists for the expansion of existing industry and the development of new enterprises.

Borax also asserts that in determining the proper rate for industrial customers, the Commission must reduce the rates to induce fuel switchers to return to the system and that the spot market for alternate fuel supplies is highly competitive and a rate decrease must beat that market. Further, Borax states these fuel switching customers have existing business relationships with oil suppliers that they will not abandon at a gas price that just barely beats the oil market. Also local utility user taxes must be considered in the overall cost of gas, and a switch back to gas could cause a loss of "grandfather" rights under local air pollution control rules. These latter items amount to a hidden cost of gas.

Following is the G-50 and G-58 rate offered by Borax as an alternative to the PG&E, staff, and TURN proposals.

Schedules	PG&E	Staff	TURN	Borax
G-50				
Tier I	$.493	$.50606	$.50966	$.49
Tier II	.446	.47774	.48134	.46
Tier III	.390	.44275	.44635	.42
G-58	.390	.44275	.44635	.42

Long-Term Gas Rate Design Policy

In this proceeding the staff is proposing a change in long-term gas rate design policy. It proposes that the Commission approve its recommendation in concept now, then later implement it in detail in the rates in the spring GAC for PG&E and the spring CAM for SoCal. This essence of the staff proposal is to shift from the current rate design, which is based on alternative fuel costs, to one based on the cost of gas.

Staff offers its proposal as a response to the continuing difficulties in managing the current rate design in the face of several significant changes in the gas industry. First, the decline in oil prices to levels below those of still-regulated gas prices has forced the Commission to consider numerous requests for special rates indexed to alternative fuel prices, in order to keep low priority industrial customers on the gas system. Administration of the special "targeted" rates that the Commission has approved is difficult and complex, especially since the Commission has limited knowledge or control over the rapid fluctuations in the alternative fuel markets. Second, substantial new opportunities now exist for gas-to-gas competition among California's gas suppliers. A recent series of orders by the FERC has removed contractual constraints on competition among the pipelines supplying California. The deliverability of gas continues to exceed the demand, and the wellhead prices of several categories of gas will be deregulated on January 1, 1985. In this environment the staff argues that existing rate design policies, which tie industrial rates to artificial alternative fuel prices, are not structured to take advantage of the rapidly increasing competition among gas pipelines and producers. A new rate design policy in which rates for all customers move with the cost of gas will, the staff asserts, harness the new competitive forces in the gas market to yield lower rates for all gas consumers. In this way, the staff seeks to avoid a situation in which the benefits of competition accrue just to those customers with alternative fuel capability who can command lower rates with the threat of fuel switching. While the mechanics of the staff's proposal would be determined in the spring GAC and CAM proceedings, in concept the proposal would work as follows:

> "Gas is purchased on a least-cost basis first with the incremental source of gas being the most expensive source supplied to the system to serve existing demand. Customers are matched with gas supply such that the highest priority customers have included in their rates the least-cost source of gas, and the incremental load is served by the more expensive incremental gas. As blocks of gas are matched up with blocks of demand, there is an allocation of pipeline and

distribution fixed costs to derive the completed rate." (Staff Opening Brief, p. 29.)

This allocation of fixed costs would reflect a division of the market between core and noncore customers. The core market is defined as customers in Priorities P-1 through P-2a; the noncore market consists of customers with fuel-switching capability. The staff and the parties who commented on the staff proposal are in general agreement that making this allocation of fixed costs presents the Commission with a difficult task, one that holds the greatest risk of advantaging or prejudicing any particular customer class.

The absolute cornerstone of the staff's proposal is that rates to the noncore market will not change unless the cost of gas changes. This will eliminate the current practice of targeting industrial rates to the cost of alternative fuels, then setting high priority rates residually. The staff asserts that strict Commission adherence to such a policy would clearly signal gas producers that increased sales to the California industrial market will result only if the producers reduce wellhead prices to competitive levels.

CMA and Borax oppose the staff proposal, although in their opening brief both parties recommended that the Commission adopt in principle the staff plan on the premise that it advanced a policy of gas rates based on gas costs. CMA and Borax now oppose the proposal, based on the fuller explanation of the policy contained in the staff's initial brief. Both CMA and Borax are concerned that the assignment of higher cost gas supplies to low priority customers could hinder the Commission's ability to set gas rates competitively with alternate fuels. CMA and Borax are also concerned that conceptual approval of the staff's long-run rate design will preclude the Commission from adopting any of the gas carriage proposals that are now before it in OII-84-04-079. Gas carriage was not an issue addressed in this proceeding, Borax argues, and CMA asserts that the staff policy is premised on the assumption that PG&E will not have to compete against other gas suppliers for the low priority market. Such a premise would appear to preclude gas carriage arrangements.

TURN and PG&E oppose adoption at this time of the staff proposal, stating that it lacks sufficient detail to permit any comprehensive response. TURN states that it will vigorously oppose any attempt to return to an allocated cost of service concept. While accepting staff's analysis of the need for a rate design policy that allows reflection of changes in the cost of gas in industrial customers' rates, TURN suggests an equal percentage or equal cents per therm rate policy will adequately achieve that goal for the near term. TURN also expresses concern that an expedited offset proceeding such as the spring GAC or CAM may not be an appropriate forum for considering such a major change in rate design policy. TURN suggests that this change be considered in PG&E's next general rate case. Like TURN, PG&E agrees with the basic concept of the staff proposal, that changes in rate levels should be more closely linked to changes in gas costs. PG&E feels that the proposal is deserving of immediate future analysis and study, but that the Commission should reserve its approval of the proposal until its details have been presented.

We welcome the public staff's long-run rate design proposal as a thoughtful and timely response to the dramatic changes that are occurring in the natural gas industry. We share our staff's desire to move away from the complexities of targeted industrial rates linked to alternative fuel prices. We also recognize the importance of sending gas producers a strong signal back from the burnertip, to the effect that gas sales will increase only if producers reduce or maintain the cost of gas at competitive levels. Finally, we are attracted to the idea of linking all rates, across the board, to the cost of gas, in order to provide all gas consumers with the potential benefits of expanded competition among gas pipelines and producers.

We will not approve the staff's proposal at this time. Although the concept is appealing, we do not want to commit ourselves to the path proposed by staff without some assurance that a fair and reasonable allocation of supplier and distributor fixed costs, a crucial element in the staff proposal, can actually be achieved. We share the concerns of PG&E and TURN that the details of this allocation should be studied before the concept is approved.

More importantly, the expedited time frame of this proceeding did not allow consideration of the staff proposal alongside other options for responding to the fundamental changes in the gas industry. We have been conducting an investigation into allowing carriage of customer-owned gas within California (OII 84-04-079). A number of parties to that proceeding urge us to allow intrastate gas carriage, both as an alternative to targeted rates for keeping low priority customers on the gas system, and as a way to promote competition at the wellhead. Our staff, which originally supported carriage, now prefers its long-range rate design proposal, and urges us to delay approving carriage until the impact of its rate design is felt and gas producers begin to reduce prices for all customers. Until then, staff fears that carriage would segment the market, and allow carriage users to siphon off low cost gas, thus raising the average cost of gas to the distributor's captive core customers. Because carriage is a distinct alternative to the staff's rate design proposal, we prefer to give all interested parties, especially those in OII 84-04-079, an opportunity to address the common issues raised by both alternatives, or to propose further options. For this reason we direct our staff to formulate expeditiously a proposal for how we may consider these issues.

Discussion

All participants on rate design issues were in agreement that the decrease in rates now possible provides a unique opportunity to realign rates and to reflect in those rates the fact that gas supply costs are falling. Over the past decade industrial sales have declined as customers left PG&E's system or reduced consumption for a variety of reasons, including substitution of oil for gas. This reduction of sales has resulted in a shift of the fixed cost recovery to the less elastic residential and commercial customers. To reverse the decline in industrial sales and increase their contribution to recovery of fixed costs we must design rates that will encourage the return of the industrial customer to the system. An increase in industrial sales will offset the suppliers' price adjustments and encourage further price reductions. We are also concerned that high priority customers share in the recent gas cost decreases; it is our intention that all gas consumers should enjoy the benefits of increased competition among California's gas suppliers.

The primary difference in rate design between PG&E and staff is that PG&E would allocate approximately 2/3 of the revenue decrease to industrial Schedules G-50 and G-58, with the remaining 1/3 allocated on an equal percentage basis to high priority customers, while the staff proposes that approximately 2/3 of the decrease be split among Schedules G-50, G-58, G-55, G-55A, and G-57. Of the staff proposal 1/3 of the GAC decrease would be allocated to Schedule G-55. The staff proposal also contains no decrease for Tier II of the residential class.

TURN recommends an equal cents per therm reduction shared among residential, commercial, and industrial customers. TURN, like PG&E, also opposes the staff's proposed reduction of the G-55 rate.

We will adopt TURN's recommended method for allocating the rate reduction, although we will calculate the equal cents per therm decreases for the three customer classes as a whole, based upon the total sales for each class. TURN's calculation ignores steam electric plants, enhanced oil recovery facilities, and industrial users on the G-80 series tariffs as part of the industrial class. We will include G-55, G-57, G-59, and G-80 through 86 sales in the total sales for the industrial class. The resulting equal cents per therm method is consistent with the method we use in today's SoCal CAM decision. We believe that this equal sharing of these significant rate reductions will maintain present rate relationships while sending the message to gas producers that changes in the cost of gas will be shared by all gas consumers.

Our equal cents per therm method will result in about 59% of the retail rate decrease being allocated to the industrial class, 15.5% to the commercial class, and 25.5% to residential ratepayers.

Resale. We do not agree with staff that a separate balancing account be established for each resale customer. The same problems with SoCal's resale customers are not present with PG&E's, and therefore the same approach is not necessary. In addition, because at least one of PG&E's resale customers sets rates which mirror PG&E's, it could be difficult for that customer to continue to follow that policy.

Industrial. We are persuaded that this is the opportunity to reduce substantially gas rates for PG&E's industrial customers. After careful consideration of all arguments we believe the rate design proposed by PG&E is, with two exceptions, the most comprehensive and fair to all parties. In addition, PG&E's proposal will be the most effective in luring lost industrial customers back to the gas system, while sending to suppliers the signals necessary to encourage even more price concessions.

The two exceptions are the 39¢/th rates proposed for customers with #6 alternate fuel capability in Schedule G-58 and the third tier of G-50. We note that the Energy Information Administration's alternate fuel rate for nonexempt industrial customers is currently 41.5 ¢/th. Therefore we question whether many of PG&E's industrial customers could legally use a 39 ¢/th rate without the time-consuming process of obtaining an exemption from incremental pricing from the FERC. We also share TURN's concern that a 39 ¢/th rate would amount to "giving it all now" to industrial customers. Industrial rate reductions are the most attractive incentive which we can offer to gas producers to encourage them to make further price reductions. A 39 ¢/th rate for #6 alternate fuel customers risks leaving us with no downward flexibility for the future. We prefer to hold back a portion of the reduction as an incentive for producers to lower prices further in coming months. We have considered PG&E's argument that the real cost of gas to some industrial customers is higher than the tariffed rate, due to utility users' taxes or air quality considerations. Because the evidence on these extra costs of using gas is anecdotal, we cannot set rates based upon the assumption that these extra costs occur throughout PG&E's system. We will adopt a 41.5 ¢/th rate for Schedule G-58 and the third tier of G-50. This is a 13% reduction from the present rate. We find that a rate at this level will be very competitive with #6 fuel oil, and should result in a substantial increase in sales to customers on these schedules.

The EOR rate (G-59) has been based on the marginal cost of gas plus a reasonable contribution to margin. We will accept PG&E's proposal to continue its existing G-59 schedule and bidding procedure.

Both PG&E and staff recommend that food processing Schedule G-86 established by D.84-08-116 not be continued. We agree. This schedule was temporary and the reduction in the other G-80 series will result in lower gas costs for food processors which should be competitive with other fuels.

With respect to the ammonia surcharge question, we agree with staff's inclusion of $4,900,000 for PG&E's assumed share for the forecast period October 1984 through September 1985.

G-55 and G-57 Powerplant Rates. The staff was the only party to propose lowering the G-55 and G-57 powerplant rates at this time. Although we agree with other parties that significant reductions to industrial customers deserve top priority, we find compelling reasons, having achieved these reductions, to allocate the remaining decrease within the industrial class to the powerplant rates.

At its present level of 54.05¢/th, PG&E's G-55 rate simply is out of touch with the realities of today's fuel markets. The rate is based on the contract price in PG&E's long-term low-sulfur fuel oil (LSFO) agreement with Chevron. PG&E forecasts no purchases under this contract in the near future; it could obtain LSFO on the spot market for substantially lower prices. The comparable powerplant gas rate in Southern California Gas Company's service territory is now about 43¢/th, reflecting more closely the actual alternative fuel cost for powerplant use. At its present level, the anomalous G-55 rate results in a subsidy of PG&E's gas ratepayers by its electric ratepayers. This subsidy may no longer be appropriate in a period of downward pressure on gas rates due to increased supplier competition, and upward pressure on electric rates from possible major additions to rate base. In addition short-run avoided energy prices paid to qualifying facilities (QFs) are based on the G-55 rate, as are cost-effectiveness tests for conservation programs. Use of a G-55 rate that is not based on current fuel markets produces misleading avoided cost price signals. We noted this problem in PG&E's last general rate case decision (See D. 83-12-068, p.340) and asked that it be addressed in the utility's next general rate case. Since that time the magnitude of the problem has grown, and the interval between PG&E's rate cases has increased to three years. Thus we find compelling reason to address this problem in the near future. In the spring GAC parties should address the appropriateness of continuing to base avoided energy prices on the G-55 rate.

In this case we will take a first step toward realigning the G-55 rate with today's fuel markets, by applying the remaining decrease in the industrial class to Schedules G-55 and G-57. This reduction of about $43 million will lower these rates to 52.6¢/th.

G-55A Cogeneration Incentive Rate. This issue is closely related to the problem with the G-55 rate. The G-55A rate was established in D.92792 to provide an incentive for gas-fired cogeneration. The G-55A tariff allows a cogenerator to use the lower of the G-55 rate or the otherwise applicable industrial rate for that portion of its gas usage equivalent to what PG&E would have burned in its gas-fired powerplants to produce the same amount of electricity. The remaining gas usage is billed at the applicable industrial rate. A cogenerator receives avoided cost prices for the electricity it produces; these prices are based on the G-55 rate. The G-55A rate was established recognizing that cogeneration is a more efficient use of gas than simply burning gas to produce electric power or useful thermal energy alone. The G-55A tariff put PG&E and cogenerators on an equal footing in purchasing gas used to generate electricity; it removed the disincentive to cogeneration which existed when industrial gas rates were higher than G-55. Now the opposite is true; the following table compares G-55 and G-55A rates at present and as authorized in this decision:

	Present	Proposed
G-55A Cogeneration Gas Rate	50.2¢/th	44.0¢/th
G-55 Powerplant Rate	53.1	52.6
difference	2.9	8.6

Clearly the substantial industrial rate reductions which we authorize today will also substantially increase the differential between the G-55 and G-55A rates. We are concerned that what we established as an incentive for cogenerators may now become a windfall. Cogenerators can buy gas at low industrial rates, then generate electricity for sale at avoided cost prices based on the artifically high G-55 rate.

There appear to be several solutions to this problem. One is to realign the G-55 rate with today's fuel markets, as discussed above. This will be explored in PG&E's spring 1985 GAC proceeding. A second possibility involves a revision of the G-55A tariff. The existing tariff would continue to apply when the industrial gas rate applicable to a cogenerator exceeds G-55. However, when the industrial rate falls below G-55, the cogenerator would pay the G-55 rate for an amount of gas equal to the BTU equivalent of its KWh electricity production. This would charge the cogenerator the higher powerplant gas rate for that portion of its input gas BTU's which clearly serve just to produce electricity. The remaining gas usage would be billed at the lower industrial rate. We direct all interested parties in the upcoming spring

GAC proceeding to comment on this proposal, or to propose other options for revising the G-55A tariff in order to address the current disparity between G-55 and G-55A rates.

In this case IEP has proposed a modification in the G-55A schedule that is not directly related to the above concerns. This modification would allow cogenerators with auxiliary boilers with #6 fuel oil capability to qualify for gas service under Schedule G-58, even if the cogeneration equipment required #2 fuel oil. IEP appears to have raised a genuine problem, but we will deny without prejudice the proposed stipulation between PG&E, staff, and IEP, in view of our desire to review thoroughly the G-55A tariff in PG&E's spring GAC. We encourage IEP and PG&E to continue working on resolving the technical and administrative problems with the IEP proposal.

Commercial. With the potential fuel switching by the commercial customer, it is important that the G-2 rate be competitive with propane. Both staff and PG&E recognize the problem by recommending a new second tier rate schedule to customers with the ability to burn propane. The proposal to establish a second tier for commercial customers is reasonable. We will adopt PG&E's proposed G-2B Schedule, due to PG&E's unrebutted assertion that it cannot readily identify customers with true propane-burning capability. We urge PG&E to continue to work on developing its ability to identify potential commercial fuel switchers.

Residential. The tier one baseline rate is set at 85% of the system average, with the Tier II rate set residually.

Summary. The following table reflects the rates to be adopted, which result in a net revenue decrease of $193,485,000.

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

12 MONTHS BEGINNING OCT 1, 1984

SUMMARY OF RATES AND REVENUES (1)

Line No	Classification	Sales (Mth)	Present Rates(3) ($/therm)	Present Revenues (M$)	Adjustment ($/therm)	Adopted Rates ($/therm)	Adopted Revenues (M$)	Increase (%)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Residential (2)							
1	Tier I (Baseline)	1501006	.47433	711972	-.02804	.44589	669283	-6.00
2	Tier II	474002	.82119	389245	-.01293	.80826	383116	-1.57
3	Total Residential	1975008	.55758	1101217	-.02472	.53286	1052399	-4.43
	Nonresidential							
4A	G-2A	1093612	.66168	723620	-.01255	.64913	709895	-1.90
4B	G-2B (LPG Alt)	113099	.66168	74835	-.14241	.51927	58728	-21.52
5	G-50 Block 1	304584	.53903	164179	-.04603	.493	150159	
6	" Block 2	343697	.51071	175529	-.06471	.446	153258	
7	" Block 3	106229	.47572	50535	-.06072	.415	44085	
8	G-50 Total (4)	754510	.51721	390243		.46061	347532	-10.94
9	G-55A	82920	.50189	41616	-.06203	.43986	36473	-12.36
10	G-55	2941660	.5405	1589967	-.01447	.52603	1547404	-2.68
11	G-57	17280	.5405	9339	-.01447	.52603	9089	-2.68
12	G-58	352240	.47572	167615	-.06072	.415	146221	-12.76
13	G-59	243820	.38	92651	0	.38	92651	
14	G-80,-82-84	142140	.43	61120	0	.43	61120	.00
15	G-86	0	.44	0	0	.44	0	
14	Total Nonresidential	5741380	.54882	3151006		.52411	3009110	-4.50
	Resale							
15	G-60 (Palo Alto)	35800	.42844	15338	-.0326	.39584	14171	-7.61
16	G-61 (Coalinga)	1800	.42839	771	-.03277	.39562	712	-7.65
17	G-62,G-63 (CPN & SWG)	46570	.42929	19945	-.03306	.39523	18405	-7.72
18	Total Resale	84170		36054			33288	
19	GS,GT & G-10 Adjustment	1332		-5708			-5708	
20	Total	7801890	.54891	4282569		.52412	4089089	-4.52
21	Other Operating Revenues			3600			3600	
22	Total (Gross)	7801890	.54938	4286169		.52458	4092689	-4.51

(1) Includes all revenue components

(2) Sales adjusted by 1332 Mth to compensate for G-10 discounts

(3) Present rates effective on Aug 22, 1984

(4) G-50 not adjusted for PG&E's exclusion from the PUC surcharge

Findings of Fact

1. PG&E requests authority to decrease its gas rates by $122.2 million annually.

2. The estimates of gas sales, gas takes, gas prices, and the GCBA balance as set forth in Table III of the preceding opinion are reasonable and should be adopted for the purposes of this proceeding.

3. It is reasonable to adopt TURN's recommended adjustment of $15,268,000 to the cost of gas, based upon the estimated 1984 minimum bill credit which PG&E is likely to receive from El Paso.

4. Rate increases for 1985 Gas Department attrition and LNG costs recoverable under D.84-09-089 totalling $63,577,000, will be authorized concurrently with this decision; therefore it is appropriate to apply those increases to reduce the GAC decrease.

5. An annual revenue decrease of $193,485,000 is necessary to offset changes in gas sales and gas costs, to amortize the GCBA over a yearly amortization period beginning October 1, 1984, and to reflect the increases covering attrition and LNG costs.

6. Sequencing policy provides utility management with guidelines in deciding which gas supplies to purchase, with management reserving the discretion to adapt to changing circumstances subject to a reasonableness review.

7. Current conditions make it reasonable to sequence discretionary El Paso, PGT, and California gas on a total average cost basis. Should short term cost increases resulting from this policy rise to a substantial level, this approach shold be reevaluated.

8. PG&E's proposed core purchase levels are reasonable at this time.

9. The staff's recommended 75% of contract quantity should be used in calculating average costs for sequencing purposes; this issue should be reviewed if El Paso's design sales volume changes.

10. GEDA gas should continue to be sequenced based on its incremental cost.

11. The average cost of California gas should include a proxy gathering cost of $0.34 per MMBTU. PG&E should be required to calculate the comparable cost for its own gathering system.

12. It is reasonable to adopt the staff's "window concept" for sequencing gas from different suppliers that is similar in price.

13. An appropriate size for the "window" is 1.0¢ per Dth.

14. The staff's long-run rate design proposal is a thoughtful and timely response to the changes that are occurring in the natural gas industry; however, the proposal needs to be developed in greater detail and evaluated alongside the gas transportation proposals which have been presented in OII 84-04-079.

15. The rate decrease found reasonable here should be distributed to customer classes in accordance with the equal cents per therm allocation proposed by TURN, as modified herein.

16. PG&E's industrial rate design proposal is reasonable, with the exception of the 39¢/th rate proposed for Schedules G-58 and the third tier of G-50.

17. The rate for Schedules G-58 and the third tier of G-50 should be 41.5¢/th, which is the Energy Information Administration's alternate fuel rate for nonexempt industrial customers. A rate at this level will be competitive with #6 fuel oil.

18. The G-59 rate should continue to operate on a bid/auction basis and the monthly bid level should continue to be published.

19. The food processing Schedule G-86 should not be continued.

20. Staff's proposal to include $4,900,000 as PG&E's share of the ammonia surcharge is reasonable.

21. The remainder of the rate decrease to the industrial class should be used to reduce the G-55 and G-57 powerplant rates.

22. PG&E's G-55 rate is out of touch with today's fuel markets.

23. Short-run avoided energy prices paid to some qualifying facilities (QFs) are based on the G-55 rate; thus to the extent that the G-55 rate does not reflect PG&E's incremental fuel costs, those QFs are receiving a misleading price signal. This problem should be addressed in the spring 1985 GAC proceeding.

24. The G-55A cogeneration gas rate also should be reevaluated in the spring 1985 GAC proceeding. IEP's proposed modification to G-55A should be denied without prejudice, in view of the upcoming thorough evaluation of the G-55A rate. PG&E and IEP should continue to work on the technical and administrative problems with the IEP proposal.

25. PG&E's proposed G-2B Schedule is at this time an appropriate response to potential fuel switching among commercial gas customers.

26. The rates and resulting estimated revenues set forth in Table VIII will be just and reasonable and should be adopted for the purposes of this proceeding. The decrease in rates resulting from the application of such rates is justified.

Conclusions of Law

1. PG&E should be authorized to decrease its gas revenues to the extent found reasonable above.

2. PG&E should be directed to establish the new or revised rates, rules, and regulations found reasonable.

3. PG&E should follow the guidelines found reasonable herein for sequencing its purchases of gas from its suppliers. Should circumstances change, PG&E should use its management discretion to depart from these guidelines where appropriate. These departures should be subject to a reasonablenss review.

4. This order should become effective on the date of issuance because the beginning date of the forecast period of October 1, 1984 has already passed and because the attrition and LNG rate increases included in these rates are effective on January 1, 1985.

5. PG&E should monitor the new rates authorized herein and should report on their effectiveness in the next GAC proceeding. If changes are deemed to be required, PG&E should propose appropriate changes.

6. Schedule G-86 rates should be exempted from Section II of General Order 96-A, pursuant to Section XV of that General Order.

O R D E R

IT IS ORDERED that:

1. On or after the effective date of this order, Pacific Gas and Electric Company (PG&E) is authorized to file revised gas tariff schedules reflecting the rates shown in this decision and cancel its presently effective schedules. The revised tariff schedules shall become effective when filed or on January 1, 1985, whichever is later. The revised schedules apply only to service rendered on or after their effective date and shall comply with General Order 96-A.

2. PG&E shall monitor the new industrial gas rates directed to be established in this proceeding and shall report on their effectiveness and propose appropriate changes in its next Gas Adjustment Clause filing.

3. PG&E shall follow the gas sequencing guidelines found reasonable herein. If circumstances change, PG&E should use its managerial discretion to depart from these guidelines; such departures should be brought promptly to the Commission's attention and subjected to a reasonableness review.

4. PG&E shall present, in the spring 1985 GAC proceeding a calculation of the gathering cost for California gas.

5. The staff shall formulate expeditiously a proposal for how the Commission should consider the staff's long-run rate design proposal alongside the gas transportation proposals developed in OII 84-04-079, or alongside other possible options for responding to the significant changes now occurring in the natural gas industry.

6. In PG&E's 1985 spring GAC proceeding, PG&E, staff, and interested parties shall address the following:

i. whether or not short-run avoided energy prices should continue to be based on the G-55 powerplant rate.

ii. whether the G-55A cogeneration incentive gas rate should be modified due to the increasing differential between industrial gas rates and G-55. Other modifications to G-55A, such as that proposed by IEP in this proceeding, should also be addressed.

This order is effective today.

Dated December 28, 1984, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
PRISCILLA C. GREW
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

I dissent in part.
/s/ VICTOR CALVO
Commissioner

I abstain on the portion of this decision establishing gas rates for cogenerators because of my financial interest in potential small power producers.
/s/ PRISCILLA C. GREW
Commissioner

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

Joseph E. Bodovitz

Joseph E. Bodovitz, Executive Director

APPENDIX A

LIST OF APPEARANCES

Applicant: Peter W. Hanschen and Shirley A. Woo, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Michel Peter Florio and Jon F. Elliott, Attorneys at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Henry F. Lippitt, II, Attorney at Law, for California Gas Producers Association; Richard K. Durant and H. Robert Barnes, Attorneys at Law, for Southern California Edison Company; Messrs. Baker & Botts, by John Leslie, Steven Hunsicker, and Charles Darling, IV, Attorneys at Law (Washington D.C.), for Tenneco Oil Company and Conoco, Inc.; John D. Quinley, for Cogeneration Service Bureau; Keith McNair, for Shell Canada; Richard Owen Baish and Arthur R. Farmanek, Attorneys at Law (Texas), for El Paso Natural Gas Company; F. E. John, T. D. Clarke and Glenn D. Nelson, Attorneys at Law, for Southern California Gas Company; Roy Alper and Dan Richard, Attorneys at Law, for Independent Power Corporation; Earle H. Mowrey, for Transwestern Pipeline Company; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth and Richard C. Harper, Attorneys at Law, for California Manufacturers Association; Messrs. Chickering & Gregory, by C. Hayden Ames, Attorney at Law, for Geothermal Generation, Inc.; Messrs. Chadbourne, Parke, Whiteside and Wolff, by Jerry R. Bloom, Attorney at Law (New York) and Wayne L. Meek, for Simpson Paper Company; Harry K. Winters, for University of California; E. D. Yates, for California League of Food Processors; Brian Sway, for Capitol Oil Company; David Branchcomb, for Henwood Associates, Inc.; Jan Hamrin, for Independent Energy Producers; Messrs. Luce, Farward, Hamilton and Scripts, by Robert E. McGinnis and Steven S. Wall, Attorneys at Law, for U.S. Borax & Chemical Corporation; Gerald J. La Fave, Attorney at Law (Michigan), for California Farm Bureau Federation; Randy Baldshun, for City of Palo Alto; Messrs. Downey, Brand, Seymour and Rohwer, by Philip A. Stohr, Attorney at Law, for Anheuser-Busch, Inc. and Nabisco Brands, Inc.; Timothy J. Ryan and Janet C. Hoyt, Attorneys at Law, for Reichhold Energy Corporation.

Commission Staff: Timothy E. Treacy, Attorney at Law, and Grayson Grove.

(END OF APPENDIX A)

A.84-08-067
D.84-12-067

Commissioner Victor Calvo dissenting.

While I concur with all other portions of this decision, I must dissent regarding the way in which the $193 million reduction in gas rates is apportioned among Pacific Gas and Electric Company's (PG&E) customer classes. In particular, I believe that the large reductions to certain commercial and industrial customers are excessive, and prevent PG&E's electric customers from receiving an equitable share of the reductions in purchased gas costs.

Even though 38 percent of PG&E's gas sales are to its own generating plants, today's decision allocates only 22 percent of the rate reduction to this rate schedule. By contrast, PG&E's other industrial customers, representing only 20 percent of gas sales, receive 51 percent of the $193 million reduction.

I agree that reductions on this order are appropriate in the Southern California Gas Company's (SoCalGas) gas adjustment clause (GAC) decision issued today, because its industrial rates are much higher than in PG&E's service area. I also agree that rate reductions somewhat above the system average should be given to certain of PG&E's industrial and commercial gas customers, in order to make natural gas more competitive relative to other fuels available to them. However, today's PG&E decision goes too far too fast.

A more equitable sharing of PG&E's rate reduction would provide the following benefits:

- It would reduce the current large subsidy of gas rates by electric rates, and moderate large electric rate increases which are anticipated during 1985.

- It would hold back more of PG&E's requested industrial/commercial rate reductions as a stronger incentive for gas suppliers to reduce prices further.

- It would moderate the difference between gas rates some cogenerators pay (G-50 or G-58) and the basis of short-run avoided cost prices (G-50) and would send more accurate price signals to all cogenerators and small power producers.

- It would be more consistent with the gas rates adopted today for SoCalGas's industrial and commercial customers.

For these reasons, I do not believe that the majority of the Commission has attained the "delicate balance" in gas rate design for PG&E which we sought.

Victor Calvo

VICTOR CALVO
Commissioner

December 28, 1984
San Francisco, California