Decision ~~84 08 116~~ AUG 7 1984

ORIGINAL

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 April 1, 1984, under the Gas Adjustment Clause. (Gas)	Application 84-03-07 (Filed March 2, 1984)

(See Appendix A for appearances.)

I N D E X

Subject	Page
OPINION	2
Summary of Decision	2
Evidence Presented	2
Revenue Requirement	3
Gas Cost Balancing Account	4
Sales Forecast	5
Gas Purchase Sequence Guidelines	7
Sequencing of California GEDA Gas	9
Forecast Price of California and Rocky Mountain Gas	12
"Equivalency" Steps of Gas Sequencing	14
El Paso Minimum Bill Deficiency Payments	16
Losses and Unaccounted for Gas	18
Carrying Cost of Prepaid Gas	19
Allocation of Revenue Increase - Rate Design	22
System Average Rate	24
Resale Rates	25
Propane as an Alternate Fuel (G-2)	27
G-50 and G-55	28
G-58	28
Food Processors' Rate Levels	29
Special Conditions - G-58	32
US Borax Cogeneration Rate Proposal	33
New Industrial Rates	36
G-80 Incentive Rate	36
G-82 Auction Rate	37
G-84 Contract Rate	39
Contribution to Margin	39
Definition of Incremental Sales	40
Applicability of G-80, G-82, and G-84 to P-2 customers	42
Availability of Incentive Rates to Resale Customers	43
Prior Approval of Contract Rates (G-84)	44
Confidentiality Issues	45
Incremental Cost of Gas - G-84	46
Curtailment under G-80 and G-82	46
Priority Provisions Tariff Rule 21	47
CMA Arguments Reincentive Rates	48
Adoption of New Schedules	49

I N D E X

Subject	Page
Adopted Summary of Rates and Revenues	50
Findings of Fact	52
Conclusions of Law	53
ORDER	53
APPENDIX A - List of Appearances	

O P I N I O N

In this application, as filed, Pacific Gas and Electric Company (PG&E) seeks authority to increase natural gas rates by $186.6 million annually under the Gas Adjustment Clause provisions of its tariff.

Public hearings were held before Commissioner Donald Vial and/or Administrative Law Judge (ALJ) John Mallory in San Francisco on April 9, 10, 12, 13, and 30, and May 1 and 2, 1984. The application was submitted subject to filing of concurrent opening briefs due May 18, 1984 and closing briefs due June 4, 1984.

Summary of Decision

This decision grants PG&E annual increased revenues of $73.387 million for gas services in the forecast year beginning April 1, 1984. The decision also establishes new temporary reduced rates applicable to (1) service to food processors who are able to burn high sulphur fuel oil (HSFO) as an alternate fuel, and (2) the incremental usage of large customers who are current or potential fuel switchers to encourage those customers to return or remain on PG&E's system.

The decision denies a special gas rate to United States Borax and Chemical Corporation (US Borax) and customers similarly situated for cogeneration service. US Borax sought a rate on the same level as Southern California Gas Company's (SoCal) special cogeneration rate.

Evidence Presented

Evidence was presented on behalf of PG&E, the Commission staff (staff), California Gas Producers Association (Gas Producers), California League of Food Processors (Food Processors), US Borax, and the California Manufacturers Association (CMA).

Briefs were filed by PG&E, staff, Gas Producers, CMA, Food Processors, US Borax, and Towards Utility Rate Normalization (TURN).

PG&E and staff presented data with respect to the recorded amounts in the Gas Cost Balancing Account (GCBA) and estimated accumulations in the GCBA to March 31, 1984, the end of the current period. They also presented forecast data with respect to estimated gas supplies and sales in the forecast period (12 months beginning April 1, 1984). Based on this information, PG&E and staff estimated the revenue requirement necessary to amortize the GCBA for the 12-month period beginning April 1, 1984.

A step in determining gas costs in the forecast period is the sequencing of gas supplied at varying costs by different sources of supply. Gas Producers presented evidence in support of greater purchases of California gas through changes in the sequencing of gas supplies in the forecast period.

Other participants in the proceeding presented evidence in support of their rate design proposals.

Revenue Requirement

The rates proposed by PG&E are designed to recover only its gas costs under its tariff Gas Adjustment Clause (GAC).

PG&E and staff were directed by the ALJ to include in their briefs information on the status of El Paso Natural Gas Company's (El Paso) minimum bill requirements, the updated electric sales forecast included in its present Electric Cost Adjustment Clause (ECAC) proceeding (Application (A.) 84-04-028) based on the April snow survey, and sales to US Borax not previously reflected in their rate and revenue exhibits. As a result of this new information, PG&E reduced its requested revenue increase from the $186.6 million originally sought in this application to $82,055,000.

The staff recommended a revenue requirement of $209 million, which reflects the elimination of all Schedule No. G-59 (G-59) sales and minor adjustments to G-50 and three-month commercial paper rate, a minor change in the unit price of gas, and a minor change in the carrying cost for prepaid gas for the month of June 1984. PG&E believes G-59 sales should be included in the revenue requirement. PG&E accepts the more recent commercial paper rate as appropriate. However, PG&E believes that its own method of computing the prepaid gas carrying cost of gas for June is appropriate and the staff adjustment should not be made.

Gas Cost Balancing Account

In order to determine the estimated revenue requirement for the forecast period, it is necessary to estimate the balance in the GCBA as of the beginning of the forecast period.

The staff used the recorded March 31, 1984 GCBA balance, which included the recorded March three-month commercial paper rate (CPR) of 9.83%, while PG&E used an estimated CPR of 9.2%. No party objected to the use of the staff's figure.

PG&E made no adjustment to the recorded balance in the GCBA for billing lag in the Supply Adjustment Mechanism (SAM) tariff, as required by Decision (D.) 84-02-003, for the years prior to January 1, 1984. However, such adjustment was made prospectively. At the time this application was filed, the Commission had not acted on PG&E's application for rehearing seeking annulment of the directive in D.84-02-003 requiring retroactive adjustment of the GCBA for billing lag. D.84-05-037, dated May 2, 1984, terminated the stay of D.84-02-003, denied PG&E's application, and affirmed the directive. PG&E objects to making the retroactive billing lag adjustment to GCBA because it has petitioned for a writ of review of D.84-05-037 from the California Supreme Court (S.F. Nos. 24731, 24732, and 24733), and it "is confident that the company's position will ultimately be vindicated."

The Commission's directive in D.84-02-003 is now in effect and must be followed. Ordering Paragraph 2 of that decision ordered PG&E to adjust its SAM balancing account by $13.5, and to further adjust the SAM balancing account by amounts associated with changed margins in 1983 and 1984. The fact that PG&E plans to seek court review of that decision is not determinative; we will impute the necessary changes in the GCBA to reflect our order in D.84-02-003.

The recorded GCBA will be adjusted as indicated above. The amount adopted for the purposes of this proceeding is set forth in Table 1, infra.

The staff of the Utilities Division recommended that PG&E's GCBA be assigned priority attention for auditing by staff financial examiners. This is a matter for the internal management or the division involved, and does not require a directive from the Commission.

Sales Forecast

PG&E asserts that there are several developments which arose during and after the hearings which should be reflected in this decision; most significantly the Energy Clause Adjustment Clause (ECAC) updated forecast, which if adopted, would reduce the revenue requirement by $92.4 million. That forecast, based on the latest (April) snow survey shows that significantly less California generated hydro power will be available in the latter part of the forecast period because of poor rainfall between January and April 1984. The substitution for the unavailable low-cost hydro generation would be electricity generated at PG&E's fossil fuel plants using natural gas as fuel. This would result in greater sales of Priority (P) 5 gas at a rate above the incremental cost of gas, providing an additional net contribution to the gas margin.[1]

As indicated above, the sales forecasts of staff and applicant were amended to reflect the greater expected sales under G-55 because of increased electric generation with natural gas. These sales forecasts also were revised to reflect additional sales

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[1] The May 16, 1984 amendment to A.84-04-028 (ECAC), containing the April snow survey data and the related generation mix, also indicates that the dispute between Chevron USA, Inc. and PG&E concerning their 1981 contract for the purchase of low-sulfur fuel oil (LSFO) has been settled by compromise. and the base price of LSFO (exclusive of underlift charges) remains the same as that on which PG&E's boiler fuel (G-55) rate is established. Therefore, the G-55 rate would remain unchanged.

to US Borax, based on US Borax's testimony that it would increase its forecast period sales because of the operation of a new cogeneration unit beginning June 1, 1984. All parties concur in these adjustments.

Our staff proposed that the forecasted sales under G-59 applicable to enhanced oil recovery (EOR) be eliminated. The staff witness testified that no G-59 sales were made in the last GAC forecast period ending April 30, 1984, because no contracts have been entered into with oil refineries. One of the reasons is that the G-59 rate exceeds the cost of using field crude oil as fuel. In order to establish a G-59 rate below the field crude oil price, PG&E must obtain an exemption from Federal Energy Regulatory Commission (FERC) from the National Gas Policy Act (NGPA) minimum gas pricing provisions. That exemption was granted on June 25, 1984.[2] Another reason for the lack of G-59 sales is the need for additional facilities in order to serve potential G-59 customers.

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[2] The order in FERC Docket No. SA84-13-000 reads as follows:

> "PG&E's petition, treated as an application for exemptive order of the Director pursuant to section 206(d) of the NGPA and § 282.206(b) of the Commission's rules, is granted to the extent provided herein and the non-exempt large-boiler industrial user's facilities that are the subject of CPUC Rate Schedule G-59 are exempt from incremental pricing under the NGPA for a two-year period commmencing, and effective as of, the first day of the billing month of July, 1984."

TURN argued in its brief that it would be reasonable to take a middle ground between the over-optimistic PG&E estimate and the pessimistic estimate of the staff on EOR rates. TURN would assume that EOR sales could begin in October 1984, and would impute EOR sales for October 1984 through March 1985 of 15,661 Mdth.

PG&E has overcome the most important hurdle to achieving EOR sales by obtaining the exemption from NPGA pricing requirements. It appears that EOR sales could start as soon as facilities can be constructed to provide gas to potential customers. In light of these factors, TURN's analysis appears reasonable and will be adopted.

The adopted levels of sales reflect changes from PG&E's application agreed upon by the parties as follows: A restatement of estimated sales under former G-52 (now shown as G-50 sales) to G-58, increased sales to US Borax, and the updated G-55 sales forecast in A.84-04-028 (ECAC). Sales under new schedules (G-80 et al.) for industrial customers are not capable of estimation and no provision for additional sales under the new schedules are included.

The levels of gas sales which we find reasonable are set forth in Table 1, infra.

Gas Purchase Sequence Guidelines

PG&E manages its daily purchases of natural gas from its several sources by means of a detailed set of guidelines or steps, referred to as a purchasing sequence. These steps are designed to comply with contractual and operational constraints, and to minimize the cost of purchased gas. Applicant's current sequencing policy is set forth in the direct testimony of witness Pretto (Exhibit 1).

PG&E purchases natural gas from four suppliers: El Paso, Pacific Gas Transmission Company (PGT) which transports Canadian produced gas, Rocky Mountain producers, and California producers.

The current order of gas purchases used to meet gas requirements, and the order that PG&E supports in this proceeding is as follows:

1. California Gas minimums.
2. Coalinga Nose storage field withdrawals.
3. El Paso minimums.
4. Canadian gas contract minimums.
5. Rocky Mountain gas minimums.
6. California gas to annual obligation.
7. California gas above contract obligation with a cost less than El Paso (Economic Cal Gas).
8. El Paso gas to 40% of available supply.
9. Canadian gas to the equivalent of 60% of daily contract.
10. El Paso gas to maximum placeable levels.
11. California gas to maximum placeable levels.
12. Canadian gas to maximum placeable levels.
13. Rocky Mountain gas to maximum placeable levels.

The order of steps 7 to 13 takes into account contractual obligations, operational constraints, the commodity cost of gas, unavoidable costs, and policy considerations. The staff generally concurs with PG&E's gas sequencing order and reflected that order in its calculations of gas costs forecast for the GAC period. The two areas of controversy in the proceeding addressed (1) what sequencing price should be used to sequence PG&E's supplies of California GEDA gas and (2) how PG&E should determine its "equivalency steps" for sequencing El Paso and PGT gas subject to minimum bill and take-or-pay charges, respectively. Each of these issues will be addressed below.

The staff generally concurs in PG&E's gas purchasing policies for the forecast year, including the PG&E's rationale that "sequencing decisions should continue to send a strong signal that Canadian export pricing policy changes should be implemented."[3]

Sequencing of
California GEDA Gas

For its affiliated Gas Exploration and Development Adjustment (GEDA) Economic Cal Gas purchases, PG&E presently uses $3.656 per MMBtu, the maximum lawful NPGA ceiling price. But, for the purposes of sequencing its affiliated GEDA gas purchases, a weighted average sequencing price of $2.62 MMBtu is used.

Gas Producers argued that the lower sequencing price is not reflected in PG&E's revenue requirement, so that PG&E's ratepayers do not receive the benefit of the lower sequencing price paid to PG&E's GEDA affiliate, National Gas Corporation. Gas Producers argued that, in addition to the NPGA ceiling price for GEDA gas purchases, PG&E also plans to collect an additional $.0239 MMBtu GEDA surcharge on all retail gas sales. Based on the foregoing, Gas Produrcers argued that the transfer price of $3.656 MMBtu for affiliated GEDA gas purchases should be used for sequencing gas purchases from such sources because, until a lower transfer price is used, PG&E is not providing any GEDA benefits to its ratepayers.

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[3] It should be noted here that in PG&E's annual reasonableness review (A.84-04-028) the staff proposed an incentive mechanism for PG&E (and SoCal) to negotiate the lowest possible take-or-pay minimum bill levels with their suppliers. PG&E moved to strike staff's testimony and the Assigned Commissioner and ALJ agreed that the proposal would be more appropriately considered in an OII, where all the major gas utilities could be named as respondents. At an appropriate time, the Commission may institute an investigation for the purpose of determining whether such mechanisms should be ordered.

According to Gas Producers, the overall impact of PG&E's gas purchasing policy is to transfer about $100 million of possible purchases from California gas producers whose prices are below the NPGA ceiling price to out-of-state gas producers; PG&E's exhibits show that it had 42.2 MMDth of California gas available for purchase, but would plan to purchase only 9.4 MMDth of that available supply in the forecast period.

PG&E's witness testified that if the price of GEDA gas was lowered to the sequencing price of other Economic Cal Gas for GAC purposes, there would be an increase in the GEDA surcharge rate, resulting in a net wash for ratepayers. TURN states that it would appear that PG&E should be indifferent with respect to the price paid for GEDA production; therefore, if there would be no net effect on PG&E or its ratepayers, it would be appropriate for PG&E to reduce the accounting prices paid for GEDA gas to the same level as that required of independent producers to qualify as Economic Cal Gas. This would alleviate the apparent discrimination against Gas Producers' members without any negative impact on PG&E. TURN also asserts that, since the lower price required for Economic Cal Gas sequencing reflects current market realities, the use of that price in evaluating the GEDA program would provide a more accurate picture of the relevant benefits and costs.

This issue has been developed in these proceedings in a manner which underscores this Commission's increasing concern about the impact of the GEDA program on California ratepayers. The sequencing of GEDA gas at a price below its transfer price, resulting in displacement of cheaper California gas, illustrates that the GEDA program may place multifaceted burdens on California ratepayers. For if we were to adopt Gas Producers position, the benefit to ratepayers of cheaper available California gas must be weighed against possible offsetting increases in the GEDA surcharge rates flowing from the change in sequencing of GEDA gas. This anomalous state of affairs underscores the importance of the task facing us in OII 83-12-02, our present investigation into the merits of continuing the GEDA program. Obviously the development of the record in OII 83-12-02 will have tremendous bearing on our ultimate disposition of the sequencing issues presented in this proceeding.

Gas sequencing is also an issue in PG&E's current gas reasonableness review proceeding (A.84-04-028). Staff Exhibit 22 in that proceeding states as follows:

> "The sequencing of California GEDA gas was an issue in PG&E's Gas Adjustment Clause (GAC), Application 84-03-07. The California Gas Producers Association (CGPA) and TURN expressed concern about the methods used in determining the proper sequencing and the total costs of this gas.
>
> "The Utilities Division (UD) agrees with the general notion made by PG&E that the sunk costs associated with GEDA gas need to be considered when determining a GEDA gas sequencing price. Therefore, it appears reasonable that discretionary California GEDA gas be sequenced ahead of discretionary gas produced by independent California producers.
>
> "...independent producers who are not involved in GEDA wells must lower their price well below the Section 102 ceiling price to guarantee that 100% of their available gas is taken. These producers have an incentive to lower their price and therefore increase their load factor. However, producers involved with GEDA wells have no incentive to lower their price because the sequencing prices for the GEDA wells are low. Consequently, independent California producers with a working interest in a GEDA well have an advantage with respect to sequencing over independent California producers not tied to GEDA wells.
>
> "The UD requests that PG&E in its next GAC application discuss measures that can be taken to eliminate the advantage independent producers

> with an interest in a GEDA will have. PG&E should present alternatives to the current method and note any resulting changes in sequencing policy and purchased gas costs. Furthermore, the UD will analyze this issue in detail in next year's reasonableness review."

In effect, staff asks the Commission to evaluate this issue in PG&E's next GAC application based on additional information requested to be supplied by PG&E which would reduce or eliminate the advantage that California GEDA gas producers may have over other California producers.

Gas Producers, TURN, and our staff recognize the possible discrimination between producers resulting from PG&E's sequencing policy and the price paid for California GEDA gas, but each offers a different solution to resolve the problem. We believe that the record is not complete with respect to the equitable means of resolving this issue and further detailed information, as suggested by our staff, should be produced in PG&E's next GAC proceeding as an aid in resolving this issue. Therefore, we will make no change in PG&E's sequencing guidelines and prices for California GEDA gas in this proceeding, but will address that issue in PG&E's next GAC.

Forecast Price of California
<u>and Rocky Mountain Gas</u>

The Preliminary Statement of PG&E's GAC tariff requires that the "current cost of purchased gas" reflected in GAC filings be calculated using prices in effect no later than revision date, in this case April 1 (Revised Cal. PUC Sheet No. 11404-G, Section C.7). In this application PG&E followed the tariff language in developing an average price of California gas of $3.511 per Dth (Exhibits 3 and 9). Staff, on the other hand, proposed that the cost of California gas be based on an estimate of the average prices for June and July 1984 (Exhibit 21, pp. 17-19). The projected cost is $3.561 per Dth.

In D.82-04-117 in A.82-02-10, we rejected PG&E's proposal to base the current cost of purchased gas on estimated prices, stating:

> "Another area of disagreement between the staff and PG&E concerns the prices to be used in the calculation of the cost of gas. PG&E uses the average cost of gas over the forecast period. The staff uses the prices in effect as of the revision date as required by the current GAC procedures. The staff position will be adopted." (Page 8.)

Staff witness Eisenman stated that his proposal to use estimated prices is identical to the methodology employed by SoCal in its recent Consolidated Adjustment Mechanism (CAM) application. TURN argued that the circumstances are quite different. In A.83-03-14 SoCal proposed to amend its Preliminary Statement to permit reflection of scheduled rate adjustments from its suppliers in the CAM calculation. The Commission approved the tariff change in D.83-05-056 (Finding 19, p. 23). The staff does not propose any change in PG&E GAC tariffs. The staff recommendation applies only to this proceeding.

TURN argued the alleged predictability of California and Rocky Mountain prices under the NGPA will not necessarily continue after January 1, 1985, when a greater degree of decontrol will prevail. TURN further contends that a number of California gas contracts have been renegotiated in the last year to provide prices below the NGPA ceiling in return for a higher spot in the sequence.

TURN argues that this is a poor time to inject the problems of price forecasting into GAC proceedings. It argued that, if anything, such estimates will be even more difficult in the future than they would have been in the past, when estimating was rejected. TURN urges the Commission to stay with the current method as specified in the tariffs.

We concur in TURN's arguments and adopt PG&E's method of determining the forecast price of California and Rocky Mountain gas.

"Equivalency" Steps
of Gas Sequencing

Gas purchases from El Paso are subject to its minimum bill tariff provisions and gas purchases from PGT are subject to daily contract take-or-pay provisions.

Steps 8 and 9 are the so-called equivalency steps in PG&E's gas sequencing guidelines, under which it attempts to take an equal proportion of available Canadian and available El Paso gas, to avoid minimum bill and take-or-pay gas costs on an equivalent basis up to a 60% level on an annual basis.

TURN states it does not take exception to those guidelines, since both minimum bill payments and take-or-pay charges are difficult to quantify with precision, and because it appears reasonable to avoid them on a proportional basis. TURN argues, however, that the sequencing guidelines do not achieve such proportionality. Step 9 provides for Canadian gas to be taken to the equivalent of 60% of daily contract, while Step 9 provides for "El Paso gas to 60% of available supply." TURN states that since El Paso does not necessarily make available the full contract quantity every day, use of the "available supply" criterion will prevent a percentage equivalent avoidance of minimum bill payments and take-or-pay charges. TURN asserts that this situation develops because the 75% minimum bill is based on 75% of the El Paso contract quantity, not 75% of available supply. TURN contends that no party predicated a shortfall of El Paso gas below the 75% of the daily contract quantity during the forecast period.

TURN asks that, if the Commission agrees that avoidance of minimum bill payments and take-or-pay charges on an equivalent basis is a reasonable approach, PG&E should be directed to redefine Step 9 of its sequence to include up to 60% of the El Paso contract quantity, not 60% of available supply.

PG&E states in Step 9 that it takes an equal proportion of available Canadian and available El Paso gas, which has the effect of equally avoiding take-or-pay and minimum bill liability. PG&E argued that El Paso does not always make such quantities available every day; therefore, to base the step on contract quantities would ignore the fact that there is a difference in the quality of the underlying service arrangements. PG&E states that its policy is that El Paso and Canadian purchases at this step should be on a shared take basis; this step is intended to treat purchases on an equivalent basis and thereby avoid liabilities in a relatively equal fashion. PG&E contends that if the El Paso certificate amount were used, El Paso's share would be disproportionate and El Paso would effectively be rewarded for a service arrangement that is not as reliable as the Canadian arrangement where full volumes are available at all times. PG&E believes its policy achieves true proportionality in takes, not merely in avoidance of penalties, and should be endorsed.

We have reviewed this difference in approach and conclude that the guideline should not be changed. Proposed Steps 8 and 9 in the guidelines are the same as the guidelines adopted in prior proceedings, and review by our staff has shown no advantage to El Paso, or any need to revise this gas sequencing policy. Adoption of TURN's proposal would result in no significant change in the revenue requirement for this proceeding. We will approve PG&E's proposed Steps 8 and 9 of its gas sequencing guidelines.

El Paso Minimum Bill
Deficiency Payments

PG&E forecasts (Exhibit 12) that it will be required to make a deficiency payment of $15,054,000 to El Paso under El Paso's minimum bill tariff for the forecast period.[4] Staff adopted PG&E's calculation of its El Paso deficiency payments.

TURN argued that the PG&E and staff forecasts ignore the significant makeup rights accorded under El Paso's tariff. TURN argued that SoCal's latest forecast submitted in its current CAM application (A.84-03-30) indicates that it will exceed its 75% minimum bill level during 1984; therefore, SoCal's estimated El Paso takes can be utilized to calculate the total credit available to PG&E under El Paso's tariff formula. TURN contends that PG&E's forecasted deficiency payments should be reduced by the amount of the SoCal credit in developing its GAC requirement, as TURN believes the untested forecast introduced in the SoCal CAM is accurate and sufficient for the purposes of this proceeding.

PG&E argued that SoCal's forecasts are also only estimates and that overforecasting by SoCal could lead to further undercollection by PG&E if SoCal is wrong. PG&E asks that we ignore the G-X effect at this time in determining the minimum bill liability forecasted in this proceeding.

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[4] El Paso's minimum bill provisions are contained in its FERC Gas Tariff, Rate Schedule G - General Service - California. Under that tariff El Paso assesses a minimum monthly bill to its two California customers, PG&E and SoCal. Monthly deficiencies for each customer are subject to makeup rights, whereby credits for gas takes in excess of monthly minimums offset monthly deficiency payments. On an annual basis, deficiency payments due from one customer may be offset by credits of the other customer (so-called G-X effect). (See Exhibit 18.)

PG&E also asks that we note that there will be no G-X effect under the terms of a proposed settlement of El Paso minimum bill proceeding before the FERC.[5] We note that the settlement referred to has not taken place and that changed circumstances make it unlikely that a settlement will be reached in the near future.

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[5] The terms of the El Paso minimum bill settlement are as follows: The settlement provides for a new fixed cost recovery mechanism for El Paso which will retroactively supersede the provisions that have been in effect since December 1983. Although the formal settlement documents with El Paso have been completed, the May 22 deadline for filing them with FERC was not met. A later filing will occur because of delays which have arisen out of a contemporaneous settlement of the minimum bill proceeding involving the Transwestern Pipeline Co. which FERC has consolidated with the El Paso case. Under the terms of the settlement, El Paso will be entitled to recover 27.9¢ per Dth for all gas not taken by PG&E and SoCal below the Dth equivalent of 60% of total certificated service levels (1,140 MMcf/d and 1,750 MMcf/d, respectively). This is in contrast to the currently effective minimum bill provisions, under which El Paso may recover 37.9¢ per Dth below a 75% level. Through a billing credit, PG&E and SoCal will receive a refund, plus interest, of the difference between the amount each has actually paid since December 17, 1983, and the amount each would have paid under the new fixed cost recovery mechanism. The settlement eliminates the current G-X effect, whereby if either PG&E or SoCal takes more than its minimum annual quantity, the difference can offset deficiencies incurred by the other utility.

The new fixed cost recovery mechanism will terminate June 30, 1985, or whenever El Paso's next general base rate change becomes effective, whichever is earlier. In addition, PG&E, SoCal, and El Paso have agreed to negotiate in good faith with the objective of arriving at new service agreements by April 30, 1985. These new service agreements are to take effect starting July 1, 1985.

While the SoCal forecasts indicate that its takes from El Paso in the 1984 settlement year will be sufficient to offset PG&E's deficiency payments, we will not impute that offset in this proceeding because we have not yet made a final determination regarding 1984 sales for SoCal. On the other hand, we will reduce the forecast deficiency payments to reflect the additional gas purchases by US Borax which, in this record, appear certain. PG&E's forecasted El Paso deficiency payments will be reduced by $8.5 to $6.5 million.

Losses and Unaccounted for Gas

PG&E projects that system losses and unaccounted for gas will total 18,364 MDth during the forecast period. This amount exceeds the average level of losses over the last ten years, and represents the highest annual amount since 1978. Valued at the system average cost of gas, the estimated losses approximate $69.7 million.

PG&E's witnesses could offer no explanation for wide yearly variations in recorded losses and unaccounted for gas. PG&E has initiated three projects to reduce losses, which may account for some of the downward trend over the last ten years. Because neither staff nor PG&E witnesses could explain the nature or cause of the losses, staff offered no alternative to PG&E's estimate.

TURN contends that the PG&E's projection appears to be out of line with historical experience, and urges that we adopt as reasonable the ten-year historical average of 16,586 MMcf, resulting in a lowering of the revenue requirement of about $6.7 million. PG&E corrected TURN's estimate of that reduction to $4.2 million, using a different price of gas, correcting MMcf to MMDth, and adjusting for franchises and uncollectibles. As yearly losses have exceeded the ten-year average only once in the last five years, and as the causes for yearly variations in the losses are unexplained in the record, we will adopt TURN's projection adjusted by PG&E of $65.5 million based on the ten-year average experience.

Carrying Cost of Prepaid Gas

The staff and PG&E applied different methods to calculate the carrying cost on prepaid gas. PG&E computed the estimated June 1984 carrying cost based on averaging the balance on June 1 and the balance on June 30. Staff recommended that a weighted average daily balance method be used which would require a change in the Preliminary Statement of PG&E's GAC tariff.

PG&E argued that there are many accounts which use an average monthly balance for carrying costs, rather than an average daily balance, and that it would be unwieldy to impose the staff recommended method on all those accounts.

The staff recommendation results in only a small adjustment in the revenue requiement, but would necessitate changing PG&E's Preliminary Statement and could require a major change in accounting procedures. For these reasons the staff method will not be adopted. We will adopt, however, the staff's updated CPR for March 1984 of 9.83%; the carrying costs are as developed below:

Carrying Cost for Prepaid Gas
(1000's of Dollars)

Month	Monthly Average Balance	Monthly Carrying Cost @1/12 of 9.83%
April 1984	$ 89,665	$ 735
May	89,665	735
June	116,988	958
July	144,311	1,182
August	144,311	1,182
September	144,311	1,182
October	144,311	1,182
November	144,311	1,182
December	144,311	1,182
January 1985	144,311	1,182
February	144,311	1,182
March	144,311	1,182
Total		$13,066

The GAC revenue requirements we find reasonable for the purposes of this proceeding are set forth in Table 1 in the following page.

TABLE NO 1

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

12 MONTHS BEGINNING APR 1. 1984

GAC REVENUE REQUIREMENT

Line No.	Item	M$
1	Current Cost of Purchased Gas	2922699
2	Plus Gas Cost Balancing Account	224486
3	Plus: Carrying Cost of Prepaid Gas	13066
4	Subtotal	3160251
5	Plus: Adjmt for Fran. & Uncol Acct Exp @ .794 %	25092
6	Plus Base Cost Amount	897260
7	Subtotal	4082603
8	Less: Base & GAC Revenue @ Present Rates (1)	4009218
9	Difference	73385
10	Plus Present Revenue @ Tariff Rates (2)	4120010
11	GAC Revenue Requirement	4193395

(1) Includes Returned Check Revenue

(2) May 16,1984 Effective Commodity Rates

8/08/84

Allocation of Revenue Increase -
Rate Design

Rate design guidelines applicable to this proceeding were adopted in PG&E's last general rate increase proceeding (D.83-12-068 in A.82-12-48). Those guidelines were applied, in the first instance, in PG&E's most recent GAC proceeding (D.83-12-069 and D.84-04-015 in A.83-08-38). The specific guidelines are as follows:

Step 1. Adopt a sales profile, marginal cost (alternate fuel oil price), marginal operating cost (swing fuel), revenue requirement, and system average rate.

Step 2. Calculate resale rates and associated revenue requirement.

Step 3. Calculate the indexed rates and revenue requirement (G-50, G-58, and G-59).

Step 4. Set the G-55 and G-57 rates equal to PG&E's contract fuel oil price (53.948¢/therm).

Step 5. Increase (or decrease) the average G-1 and G-2 rates by equal percentages until the revenue requirement is reached.

Baseline rates replaced lifeline rates on May 16, 1984 based on a two-tier residential rate structure. Tier 1 is set at 85% of system average rate (SAR).

Additional information is set forth in D.83-12-068 for use in applying the guidelines (as appropriate here) as follows:

1. The rates resulting from the application of the guidelines will produce total effective rates rather than preliminary rates to which are added the RCS, CFA, SFA, and GEDA revenues, as we had done in the past.

2. The rate setting utility concept shall be applied to resale rates. Thus, Palo Alto and Coalinga shall be assessed the same resale rate as CP National and Southwest Gas Corporation, including all add-ons, and none of the resale rates shall exceed 85% of PG&E's system average rate.

3. Rates set on marginal cost concepts:
   a. The lowest rate should not be less than the marginal operating cost plus 12% premium.
   b. PG&E's alternate fuel price is the current spot market price of fuel oil.
   c. The G-55 rate (PG&E thermal plant rate) and the G-57 rate (Edison thermal plant rate) should be set at PG&E's contract fuel oil price (53.948¢/therm).
   d. A system average rate is determined.

In this proceeding questions were raised as to the correct methods of determining (1) the SAR and (2) the rates for resale customers.

At issue in A.83-08-38 was the appropriate levels of gas rates for industrial boiler fuel customers having the ability to burn No. 2 and No. 6 fuel oil as an alternative fuel to natural gas. In D.84-04-015 we adopted a three-tier G-50 schedule designed to mitigate fuel switching by large industrial gas customers.[6] We also made changes in the experimental G-58 rate designed to liberalize the use of that rate, but made no change in the indexing provisions of the G-58 schedule, nor in the level of the G-58 rate. We stated in D.84-04-115 that we would review in this proceeding the changes in rates for P-4 and 5 customers established by that decision.

Prior decisions had directed PG&E and our staff to look at innovative rate structures for possible fuel switchers, while maintaining the Commission's policy of maximizing those customers' contributions to PG&E's gas margin. In response to that directive, PG&E proposed in this proceeding new rate schedules designed to avoid

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[6] The modified revenue requirement estimates made by PG&E and staff reflect estimated sales under the new G-50 rate structure. The G-50 Tier III rate is on the same level as the G-58 rate.

further fuel switching and/or return fuel switchers to PG&E's system (proposed G-80, G-82, and G-84). Food Processors and CMA proposed to reduce the G-58 rate to or below its former level of 46¢/therm. US Borax proposed a special cogeneration rate for its operations based on SoCal's special cogeneration (G-COG) rate. CMA proposed a special rate for commercial customers which have the ability to use propane as an alternate fuel.

System Average Rate

The SAR is significant because the calculation of resale and baseline rates depend on it. Staff and PG&E disagree on the calculation of the SAR. TURN supports PG&E's position. While staff and PG&E initially disagreed over whether to use unadjusted or adjusted sales in determining SAR, staff agreed in its opening brief that it was more appropriate to use unadjusted sales. However, one other disagreement remains. PG&E excluded Schedules GS and GT submetering discounts from total system sales revenue at proposed rates, and included a 4.005 Mtherm adjustment for G-10 employee discounts (this schedule provides a rate discount, but for convention is shown as a reduction in sales in the GAC revenue calculations). On the other hand, the staff witness proposed that unadjusted sales (including G-10 discount volumes) should be used in conjunction with total revenues before subtracting the submetering discount.

TURN's and PG&E's position is that discount amounts should be subtracted from total revenues before calculating the SAR, as the discount is a tariff item and, therefore, a rate component; as such, it must be reflected in the total sales revenues used to calculate the SAR.

We agree with the above rationale. SAR should be calculated using total revenues from sales after subtraction of the master meter discount, and total system sales including those sales which are conventionally removed to reflect the G-10 discount. PG&E's method of calculating SAR will be adopted.

Resale Rates

Our staff challenged the method employed by PG&E in the calculation of resale rates. It is the staff view that PG&E's method does not follow the D.83-12-068 guidelines. The multistep process used by PG&E is as follows:

1. It first calculated the resale rates based on the following factors:
   a. "ratemaking cost of gas" (which includes three items: cost of purchased gas, gas cost balancing account (GCBA), and carrying cost of prepaid gas);
   b. franchise fees and uncollectibles;
   c. contribution to margin; and
   d. GEDA.
2. It then verified that the resulting resale rate is the lesser of two amounts: the calculated resale rate or 85% of the SAR. The calculated resale rate is about 82% of the SAR, an increase of 10.7%.
3. PG&E proposes to limit the increase to resale customers to the 9.6% percentage increase proposed for other PG&E P-1 and P-2 customers, to which is added the ammonia surcharge.

PG&E urged adoption of its method to ensure that resale customers carry a reasonable portion of the undercollection in the GCBA. It is PG&E's position that the guidelines do not specifically exclude GCBA amounts in calculating resale rates.

The staff rate design witness testified that PG&E's methodology for calculating resale rates departs from the method used in D.83-12-069 in which the D.83-12-068 guidelines were first applied, and is different from the method used to calculate SoCal's resale or wholesale rates.

The staff recommends that the method actually used in D.83-12-069 be used here and, should the guidelines need clarification or change, the issue of resale rates be addressed in PG&E's next general rate proceeding. According to the staff witness, the adopted method to calculate resale rates is based on the following factors:

1. Cost of purchased gas.
2. Franchise fees and uncollectibles.
3. Contribution to gas margin.
4. GEDA.

As an alternate to the above, the staff would calculate resale rates based on:

1. Cost of purchased gas.
2. Carrying costs of prepaid gas.
3. Franchise fees and uncollectibles.
4. Contribution to margin.
5. GEDA.
6. A separate balancing account to be set up for resale customers.

As a second alternate, staff would use a methodology that would parallel the SoCal methodology.

TURN supports staff, stating that this proceeding is not one in which to conduct any detailed analysis of resale rates. It argued that resale rates should follow the existing methodology.

The guideline for resale rates in D.83-12-068 is stated in general terms and is not specific enough to determine whether GCBA balances should be included as a factor in determining resale rates. The staff witness recognized that the method actually employed in D.83-12-069 to implement the guideline may not be wholly fair and reasonable by suggesting two alternate methods. Full exploration of the reasonableness of PG&E's method or staff alternate methods was not accomplished on this record. We will follow the method employed in D.83-12-069 for purposes of this proceeding. Because of the current three-year period between general rate cases, we should explore in a future GAC proceeding the development of a more detailed and reasonable guideline for setting resale rates.

Propane as an Alternate
Fuel (G-2)

CMA proposed that we establish a rate competitive with propane for G-2 (commercial) customers who can use propane as an alternative to natural gas (Exhibit 26). CMA pointed out that we have established a lower rate for SoCal P2B customers to recognize the competition from propane. CMA assumed that aggressive marketing by propane vendors can cause loss of sales in PG&E territory. The CMA witness testified that the Commission's 1983 gas report showed that actual usage by P2B customers declined by 30.77% from calendar 1980 to 1982. The witness testified that propane can be delivered at costs less than PG&E's G-2 rate, but furnished no specific prices for propane. The witness also testified that a significant investment in new facilities on the order of $100,000 would be necessary to use propane.

PG&E opposed the CMA proposal on the basis that the proposal does not fit within its tariff definition of alternate fuel, the record does contain enough information on propane prices in PG&E's service territory to establish a precise alternate fuel, and that evidence is also lacking on the extent of gas sales lost to fuel switching to propane.

While the first reason advanced by PG&E is not fatal to CMA's proposal, the others are. The record in this proceeding is deficient in information essential to the adoption of CMA's proposal. In addition, many of CMA's concerns will be met by our authorization of the experimental incentive rate structures, which will be available to G-2 customers.

G-50 and G-55

G-50 (industrial rates) was recently revised in D.84-04-015. The fuel cost data which underlie the rates in that schedule have not materially changed since that revision and no party proposed a change in that schedule. It should not be changed as a result of this proceeding.

G-55 (electric generation and related G-57 rate) is based on PG&E's fuel oil contract. No change has occurred in that alternate fuel price and no party proposed a change in the G-55 or G-57 rate in this proceeding. These rates should remain unchanged.

G-58

In the reopened hearings on industrial design in PG&E's October 1983 GAC proceeding (A.83-08-038), PG&E proposed that the G-58 rate remain at then current rate of 46¢/therm and that the G-58 rate not be increased to 47.483¢/therm under the G-58 indexing mechanism. (The G-58 rate is indexed to the cost of No. 6 fuel oil.) In Resolution 2577, we rejected that proposal because it was made at the close of the hearing, because the parties had no opportunity to present evidence on that proposal, and because we believed that due process required the operation of the indexing mechanism. Resolution 2577 stated that the issue of indexing should be considered further in this proceeding.

This application, as filed, indicated that PG&E was considering a proposed change in the indexing mechanism. At the hearing, PG&E's rate design witness proposed no change, stating that PG&E had no compelling evidence that the 47.483¢ rate was uncompetitive. Since the last review, nine additional customers had signed up for the G-58 schedule at the higher rate and none had left the schedule. The alternate fuel price data submitted by staff and PG&E indicate that the present G-58 rate is closely matched to the cost of LSFO. Although PG&E had no evidence of the need for a change, it expressed interest in any showing which would indicate the G-58 rate was uncompetitive. Our staff and TURN support the retention of the present indexing mechanism and the present G-58 rate level.

Food Processors' Rate Levels

Food Processors presented evidence designed to show that its members can purchase No. 6 fuel oil at costs lower than 47.4¢/therm.[7] Data compiled from a survey of its members showed (in Exhibit 6 revised) that of the 25 facilities in the survey, 15 could purchase No. 6 fuel oil below 45¢/therm. It was the witness' best estimate that in 1983, 20 million therms of gas were not purchased from PG&E by food processors because of fuel switching. According to the witness the gas rate would need to be slightly below the cost of oil for the food processors using oil to switch back to gas. The witness acknowledged that No. 6 fuel oil priced below 45¢/therm was ESFO which cannot be burned in areas with high population densities because of pollution controls.

It is the position of Food Processors that a reduction in the G-58 rate which would create more sales will provide an overall increase in PG&E's gas margin and, thus, benefit all ratepayers, as demonstrated in the following table (Exhibit 33):

[7] The greatest number of PG&E customers using G-58 are food processors.

Table 2

California League of Food Processors
Illustration of the Effects of Margin
Contribution of Potential 1984 Natural Gas
Sales Under Schedule No. G-58 at Present Rate,
Prior Rate, and Oil to Gas Switching Threshold Rates

Present G-58 Rate (¢/therm)	Estimated Sales Volume (therms)	Margin Contribution ¢/therm (above 37¢/therm)	$ Margin Contribution
47.483	6,475,000	10.783	698,199
Prior G-58 Rate			
46	20,975,000	9.0	1,887,750
Threshold Rates			
45	25,475,000	8.0	2,038,000
44	55,565,000	7.0	3,889,550
43	58,865,000	6.0	3,531,900
42	58,905,000	5.0	2,945,250

The above table indicates that the margin contribution from food processors sales (based on the survey) would be maximized at a G-58 rate of 44¢/therm, if the marginal cost of gas is 37¢/therm.

In D.84-07-071, issued July 5, 1984 in A.84-03-30, we authorized SoCal to establish a temporary reduced GN-6 rate for food processors to apply until November 30, 1984, which would cover the current canning and processing season. The adopted rates are 48¢/therm within the South Coast Air Quality Management District, and 44¢/therm outside that district. The rates are subject to economic curtailment in the event SoCal's price of gas (commodity cost of incremental gas supply plus 5¢) rises above the GN-6 rate. D.84-07-071 discusses the issue of rate targeting, and indicates that the adoption of the GN-6 rate schedule is not an indication that the Commission is moving in the direction of end-use rates, but views the action as a temporary solution.

The evidence adduced by Food Processors in this proceeding supports the adoption of a 44¢/therm rate for food processors operating in areas where high sulfur (lower-cost) No. 6 fuel oil may be burned. SoCal's GN-6 rate of 44¢/therm is the same rate which would maximize contributions to PG&E's as set forth in Table 2. Therefore, we will establish in this proceeding a temporary rate for food processors (Standard Industrial Code 20 facilities) operating in areas where HSFO (0.5% sulfur content and higher) may be burned, to expire concurrently with the expiration of SoCal's GN-6 schedule (November 30, 1984). For good cause, we may extend this temporary food processor rate upon request by advice letter filing. The rate for food processors will be applicable to only "incremental sales" as defined for the new industrial rate schedules adopted in this decision (G-80, G-82, and G-84). As with the industrial rate schedules, a food processor who had left the PG&E system for more than a year would be able to purchase all of its gas requirement under the new food processor rate for the first year, subject to the constraint that this amount of gas will never drop below the customer's actual usage in the equivalent month of the preceding year. The temporary food processor rate will be subject to nonconflicting G-58 rules and applicability. Because this is an experimental rate and because it will be applicable only to a portion of the processing season, no additional sales are imputed in determining the GAC revenue requirement. Obviously, we hope that additional sales are made which contribute to the margin, and that the data obtained from this experimental rate will enable us to refine our gas rate design to the maximum benefit of ratepayers.

We have addressed the principal evidence adduced in support of changes in the G-58 rate level. With the establishment of the temporary food processors' rate, no additional changes are required in the G-58 rate. No party presented evidence with respect to changing the G-58 indexing mechanism and that mechanism should remain unchanged at this time.

Special Conditions - G-58

PG&E amended Special Condition 1 of G-58 to eliminate the restriction that no other gas source shall be interconnected to the recording type meter used for G-58 service. Special Condition 3 will be changed in a similar manner. Both proposed changes appear to effect the change recommended by staff in the last GAC proceeding, which we determined should be adopted (D.84-04-015, p. 18). These changes should be approved.

PG&E proposed to amend Special Condition 11 to provide for an adjustment to the annual minimum charge if, as a result of a change in the customer's operations or other circumstance, the customer experiences at least a 25% reduction in fuel requirements, the change is beyond the control of the customer, and the 25% reduction applies solely to the customer's G-58 fuel requirement.

Staff concurs that an amendment is appropriate, but believes that the proposed tariff language does not comport with PG&E's expressed intent. The staff testimony and opening brief proposed a change in language which it believes more accurately states the proposed condition.[8] Our review indicates an amendment to Special Condition 11 will be reasonable as it will make the operation of G-58 more flexible. The staff's tariff language should be adopted to accomplish this purpose.

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[8] Staff proposed the following: "11. If, during any contract year a customer has at least a 25% reduction in total fuel requirements (for all or a portion of which service is provided) hereunder because of (a) a change in operations or (b) because of other circumstances, either of which must be beyond the control of the customer, then upon demonstration by the customer of such reduction (in total fuel requirements), the minimum charge hereunder shall be reduced by the utility in proportion and for the duration of such reduction."

US Borax Cogeneration
Rate Proposal

US Borax seeks the establishment of a special rate on the level of the SoCal GN-34 rate applicable to gas burned by Southern California Edison Company (Edison), or SoCal's G-COG rate applicable to cogenerators, for service at US Borax's new cogeneration facility located at Boron. US Borax will sell the energy generated by it to Edison. Boron is within Edison's electric service area and PG&E's gas service area.

US Borax will sell a portion of its output from its cogeneration facility to Edison at Edison's avoided cost. Edison's avoided cost is lower than PG&E's, in part, because Edison's boiler fuel gas price from SoCal is lower than PG&E's intracompany G-55 price.

US Borax argued that if it purchased gas from SoCal, it would be served under SoCal's GN-34 tariff. That tariff contains three tiers:

First 900,000 therms per mo.	56.776¢/therm
Over 900,000 but not over 1,500,000 therms per mo.	45.120¢/therm
Over 1,500,000 therms per mo.	43.120¢/therm

Under Special Condition 2 of that tariff, cogenerators may be served under GN-34, if the cogenerators agree to P-5 curtailment provisions.

US Borax argued that if it consumes approximately 5,000,000 therms per month at its Boron cogeneration facility, the average cost of gas under SoCal's GN-34 schedule would be 45.81808¢/therm.

SoCal's GN-34 schedule is equivalent to PG&E's Schedule G-50, which is also a three-tier schedule:

First 100,000 therms per mo.	57.105¢/therm
Over 100,000 therms but not over 1,600,000	54.105¢/therm
Over 1,600,000 therms per mo.	47.483¢/therm

Assuming consumption of 5,000,000 therms per month, US Borax's average cost of gas under PG&E's G-50 schedule would be 49.66204¢/therm. According to US Borax, the difference in cost to it between PG&E's G-50 schedule and SoCal's GN-34 schedule is $192,198 per month, or $2,306,376 per year. US Borax maintains that such differential is prejudicial to it and contrary to the established Commission policy, citing D.92792 (1981) 5 CPUC 2d 650, p. 651.

US Borax also argued that if it were served by SoCal's G-COG rate, it would pay less than for gas service under PG&E's G-50 rates. The G-COG tariff is applicable to gas service for qualifying cogeneration facilities. The current G-COG rate is 45.02¢/therm. The effective G-COG rate is adjusted monthly and is based on the weighted average of episode and nonepisode day rates and volumes from the prior month's recorded usage under Schedule G-5 (electric generation). According to forecasts in SoCal's current CAM proceeding (A.84-03-80) the average forecast price for May 1, 1984 to May 1, 1985 for G-COG is 49.17¢/therm.

It is US Borax's position in this proceeding that we should follow the Commission's stated policy in D.92792 (supra) that the rate available to utilities generating electricity and the rate available to cogenerators should be equivalent. US Borax maintains that it and other similarly situated cogenerators are disadvantaged by dealing with two utilities rather than one. It asked that such cogenerators be authorized a gas rate which does not exceed the lowest rate available to a cogenerator in the service area of the purchasing utility; in this case, the SoCal GN-34 rate schedule.

Our staff, PG&E, and TURN oppose US Borax's request. Staff argued that the fact that US Borax is served gas under PG&E's tariffs does not constitute discrimination; undue discrimination occurs when a customer is treated differently than other customers similarly situated. PG&E's rates are reasonable for all service provided to customers within its service territory. For its allegation of discrimination to be valid, US Borax would have to be entitled to the lowest applicable rate offered by both utilities, PG&E, and SoCal. Staff does not believe that this was the intent of D.92792. Staff recommends that US Borax continue to be entitled to service at the lowest rates available to it under PG&E's tariff.

PG&E pointed out that only one additional customer is similarly situated as to location, and would benefit from US Borax's proposal. PG&E argued that the record in D.92792 did not encompass the situation where gas service is supplied by PG&E and the cogenerated electric is sold to Edison; therefore, the policy statements relied upon by US Borax did not contemplate dual service areas. PG&E argued that US Borax has no legal entitlement to buy PG&E gas at a SoCal rate.

PG&E also argued that all cogeneration gas purchased by US Borax would be at the third tier of G-50 at 47.483¢/therm, which is below SoCal's G-COG rate of 47.9¢/therm. In response, US Borax argued that should it not burn gas for noncogeneration purposes, it would be subject to all three tiers of G-50, bringing its average rate to approximately 49.66¢/therm. Moreover, US Borax, in its brief, has opted for rates based on SoCal's GN-34 schedule, which produces an average rate of approximately 45.82¢/therm.

We will not adopt US Borax's proposal. First, US Borax indicated that it was returning to PG&E's gas service for its manufacturing operations and those sales are included in the adopted forecast. It would be inconsistent, therefore, to assume that US Borax may not burn gas for noncogeneration purposes. Assuming that all cogeneration gas purchases will be in the third tier, the applicable G-50 rate is 47.483¢/therm. This compares with the average rate under SoCal GN-34 of 45.82¢/therm, or a differential of 1.66¢/therm. The third tier G-50 rate of 47.483¢/therm is below the SoCal G-COG rate of 47.9¢/therm originally sought by US Borax.

No undue discrimination results from maintenance of separate gas rates for similar services by two different gas utilities, or from the fact that a cogenerator is paid for its electric sales at the lower avoided cost of the purchasing electric utility than the avoided cost of the company supplying the gas for cogeneration purposes. The mere fact that a gas utility not serving the cogenerator has a lower rate than the gas utility serving that customer does not, in and of itself, justify a lower rate for the cogenerator. U.S. Borax's reliance on D.92792 is misplaced.

New Industrial Rates

In the reopened hearings on industrial rate design in A.83-08-038, PG&E made a commitment to come forward in this proceeding with proposals designed to retain gas sales and to recapture gas sales lost to fuel switching. PG&E asserts that it fulfilled that commitment with three proposed new rate schedules: an incentive rate (G-80), an auction rate (G-82), and a contract rate (G-84). These new rates are scheduled to expire December 31, 1986. PG&E requests that all three rate schedules be adopted. The staff, TURN, and Food Processors endorsed the rate schedules in principle, but suggested changes in their application or administration. CMA argued that the new rate schedules are unfair or discriminatory, and opposed their establishment for those reasons. CMA's alternative is an across-the-board reduction in industrial rates, with residential increases to make up the lost revenues.

G-80 Incentive Rate

Charges under this new schedule are to be equal to the G-58 price per therm, and the commodity charge in G-80 shall be adjusted concurrently with changes in the G-58 rate. The G-80 rate will be applicable to incremental usage of natural gas customers whose usage exceeds 100,000 therms per month. Incremental sales are defined as follows:

> First contract year: The number of days in the current billing month times the amount by which average daily usage during the current billing month exceeds average daily usage during the corresponding billing month one year prior.
>
> Succeeding contract years: The number of days in the current billing month times the amount by which average daily usage during the current billing month exceeds 80% of average daily usage during the corresponding billing month one year prior.

The incentive rate is designed to attract additional sales by offering the lowest regularly filed industrial rate for all incremental sales volumes. PG&E's witness testified that any customer's use that is in excess of the prior year's use in the same month could be billed at the G-80 price; therefore, a customer who had left the PG&E system for more than a year (i.e., had zero gas usage as a base) would be able to purchase all of his requirement under G-80 at a rate equal the G-58 rate. Other customers would be served on the otherwise applicable schedules until their use equalled that of the same month in the prior year, and subsequent purchases would be billed at the G-80 rate. The witness further testified that the incentive rate option is the most straightforward of the industrial rate alternatives in that the customer need do nothing special to qualify as it is the customer's use alone that qualifies it for the rate. In addition, because the rate is set at, and indexed to, the price of No. 6 fuel oil, it should be able to compete effectively with that energy source and higher priced sources.

G-82 Auction Rate

The G-82 rate is applicable to incremental natural gas usage by nonresidential customers. The auction procedure is described as follows:

> AUCTION PROCEDURE: On or before the 15th day of each month PG&E shall determine the level of the

> minimum acceptable bid for gas service under this schedule for the next month, the Alternate Fuel Cost for Non-exempt Boiler Fuel Customers, and whether any customer's fuel use will be nonexempt. The Utility will accept no bids which are less than the minimum acceptable level. The level of the minimum acceptable bid shall be determined by the Utility on the basis of: (1) the anticipated cost and availability of gas: (2) the cost of transporting gas; and (3) the prices of alternate fuels.
>
> On or before the 20th day of each month or the first business day thereafter if the 20th is not a business day, each customer shall nominate and communicate to the Utility a commodity rate at which said customer desires to purchase natural gas during the next calendar month and the volumes of gas to be purchased at that price. Said communication shall be in the form and addressed as specified from time to time by the Utility. The rate nominated by the customer and accepted by the Utility shall be the commodity rate for that customer during the next month.

The minimum quantity available under G-82 is 50,000 therms. Incremental sales are defined as described in connection with G-80.

The auction rate would allow PG&E to match customers' alternate fuel prices on a monthly basis, to the extent that the natural gas rate would be sufficient to cover PG&E marginal cost of gas plus a contribution to margin. PG&E would determine each month what the minimum acceptable bid for the month would be, and the volume of gas available for auction. Customers would then be invited to submit bids for specified quantities of gas. Any bids below the acceptable minimum price would be rejected. Others would be ranked from highest to the lowest accepted price per unit until all of the gas available for auction in that month had been allocated.

Customers would only be eligible to bid for quantities of gas for usage in excess of their use in the same month of the prior year. Sales up to the base use amount would be priced at the otherwise applicable schedule for each customer. Customers would be obligated to pay a minimum bill equal to the accepted bid price times the accepted quantity of gas, except in the months where sales are curtailed by PG&E. Curtailment of auctioned gas would occur either when there was a supply shortage or when service at the accepted rate becomes uneconomical and would affect these sales in reverse order of the prices nominated by the customer and accepted by PG&E.

<u>G-84 Contract Rate</u>

This rate is applicable to incremental natural gas usage of a minimum of 50,000 therms per month negotiated between PG&E and nonresidential customers. Incremental gas usage is defined the same as in G-80. The minimum price would be the NGPA alternative fuel cost for nonexempt boiler fuel customers.

Under this schedule, a customer and PG&E would negotiate the price at which incremental sales of natural gas would take place during the succeeding year. The witness explained that, because the cost of gas to PG&E over that year may vary, there is no assurance of the amount of margin contribution from the negotiated rate. The customer must be willing to commit to a minimum bill of 40% of the contracted volumes times the negotiated price. Sales under the contract are subject to curtailment in the case of supply shortage, but are not subject to economic curtailment.

The witness testified the most obvious advantage of the contract rate concept is the price stability it affords to both PG&E and the participating customer. To the extent the negotiated price proved to exceed the average of the prices that would otherwise apply during the year, PG&E would gain a larger contribution to margin. It is expected that the Commission would review each contract negotiated under this schedule.

<u>Contribution to Margin</u>

PG&E estimates that the three proposed new rate schedules would produce cumulative annual incremental sales of 175 MMth. The related estimated contributions to margin if all such sales were under a single schedule are as follows:

G-80 - $18,375,000

G-82 - $6,475,000

G-84 - $10,500,000

Definition of Incremental Sales

The parties agree with PG&E's proposed definition of incremental sales for the first year, and they agree that restrictive tariff language is necessary so that customers are not encouraged to drop off the system entirely in order to obtain a lower rate for all of their purchases the following year. However, agreement was not reached on the specific tariff language itself. We will adopt TURN's recommendation to constrain the base quantity such that it could never drop below the customer's actual usage in the equivalent month of the year preceding adoption of the tariff. PG&E shall develop and file appropriate tariff language to reflect this constraint on the amount of incremental sales in the first contract year.

Staff and TURN disagree with PG&E's definition of incremental sales for subsequent years, pointing out that for years two and three, 20% of the previous year's sales would be "incremental" whether or not there were increased sales in year one. In order to address this problem, staff witness Gustafson proposed two alternate ways of defining incremental sales in the second and third year. The first defines incremental usage as equal to any additional sales over the amount purchased in the same month in prior year for all three years; the second defines incremental sales in the second and third year of an additional 20% as incremental usage, that is additional usage over the same month of the prior year plus 20% of the incremental sales in the same month of the prior year. PG&E defines incremental usage in the second and third years as 20% of all usage in the same month of the prior year.

Under the staff proposal, G-80 customers must continue to expand their usage in the second and third years; whereas under PG&E's proposal customers who do not increase their usage can benefit from the G-80 rate. PG&E contends that its proposal will do more than the staff's to keep customers on the system in subsequent years, and vigorously supports the adoption of its proposal.

At TURN's request, PG&E prepared Exhibits 19 and 28. Table 2 of Exhibit 19 shows that if there were no increase in sales resulting from G-80, a margin loss would occur in the second year under PG&E's proposal as customers would be able to pay the lower G-80 rate for 20% of their first year base usage. According to TURN, the foregoing represents a worst case scenario of the downward risk inherent in PG&E's proposal. TURN states that under PG&E's definition, if 100% of the estimated potential sales materialize and continue through the second year, the first year margin contribution of $18.4 million would drop to $9.9 million in the second year due to a reduction in the base quantity. TURN expects that the likely result would fall between the two extremes.

TURN points out that under the staff's witness' definition, even a customer who increased usage in the first year would have few incremental sales by the third year unless purchases continued to increase every year.

TURN submits that at least 50%, if not 75% or 80% of any incremental sales from the prior year for the same month would provide a greater incentive for customers to maintain their incremental usage through the second and third year, without providing a discount for those who never increased their consumption. TURN further states that under its proposal, as long as the base quantity does not drop below the actual usage recorded in the year prior to the first year there is little risk of margin loss. TURN recommends the staff's alternate proposal be adopted, with the 20% figure increased to 50% or more.

As indicated elsewhere, we cannot accurately determine whether the proposed new schedules will generate new sales. However, we must do our best to assure that the new schedules, if adopted, will produce the results anticipated. that is, to increase sales from industrial customers, and to encourage fuel switchers to remain on PG&E's system. Under the staff's and TURN's proposed definitions, we would ensure that sales would increase and that margin contributions would continue in the second and third year. But we are not as certain that fuel switchers would be encouraged to remain on the system under the staff's and TURN's definitions as under PG&E's definition. However, weighing these considerations, we conclude that it is more important that we assure positive contributions to margin from sales under the new schedule, rather than to encourage return of fuel switchers who may make little or no margin contributions in the second and third year. We will adopt the staff's second alternate proposal for the definition of second and third year incremental sales.

Applicability of G-80, G-82, and G-84 to P-2 customers

Under PG&E's proposal all nonresidential customers, including P-2 users (Schedule G-2) without alternate fuel capability, would be eligible for the experimental rates.

The staff witness recommended that P-2 customers be able to participate in the new rate schedules, but proposed a higher G-80 rate for such customers based on the weighted average of the G-50 first and second tier rates (currently 55.404¢/therm). The staff advanced the following reasons for its proposal. Unlike G-50 and G-58 customers whose alternate fuel is oil, P-2 customers do not have a schedule which is indexed to their alternate fuel; the alternate fuel for commercial customers is largely propane, which is higher in price than fuel oil. A G-80 rate for P-2 customers between the G-2 and G-58 rates will result in the auction rate (G-82) and contract rate (G-84) being more competitive: because customers will bid or contract for a rate between the price that they would pay on the incentive rate (G-80), and their regularly filed rate.

TURN states that it is somewhat skeptical about the inclusion of P-2 customers in G-80, given that there is little or no fuel switching to recapture from this market; further, the incentive rates would constitute a much larger discount from the G-2 rate than from G-50 or G-57 rates. TURN states that the staff proposal satisfies many of its concerns in this regard, and strongly supports the staff proposal.

PG&E states that since it views the G-80 rate to be, at least in part, promotional in order to encourage all large industrial customers to get accustomed to using gas again, PG&E opposes the staff proposal as counter to the spirit of the rate.

We concur in the staff rationale and conclude that the staff proposal will be reasonable.

Availability of Incentive
Rates to Resale Customers

The staff witness proposed that the incentive rates should be available to resale customers, with all nonresidential sales to each resale customer aggregated to determine the incremental sales quantity. Each resale customer's nonresidential usage would be viewed as that of a single P-2 customer.

PG&E opposes this proposal as an unnecessary administrative nightmare which would not serve the goal of recapturing lost sales. PG&E states that there would be no way of ensuring that the benefit of the lower rate gets passed on to the customers who increased their usage. PG&E pointed out that the staff witness suggested that a pass-through of the rate savings be a requirement of eligibility for the incentive rates; but the rates of two of the systems are not regulated by the Commission. PG&E further argued that the staff proposal is unfair because ultimate customers of the resale customer would not have to meet the same volume criteria as PG&E's own customers. PG&E believes that this proposal would add unnecessary confusion to the rates, particularly given the low rates resale customers currently enjoy.

We will not adopt the staff proposal. As we do not regulate the operations or rates of two resale customers we would be unable to enforce the conditions to be imposed those customers under the staff proposal. There are no compelling reasons to extend the G-80, G-82, or G-84 rates to resale customers, but there are compelling reasons not to do so.

Prior approval of Contract Rates (G-84)

Staff and TURN expressed concern about the administration of the contract rate. PG&E has supplied considerable information about how it expects this rate to operate. In order for the rate to work competitively, PG&E believes that the terms of each contract must be kept confidential from other potential customers on the schedule. PG&E expects that the Commission would approve in advance the form of the contracts, the price and volume terms of each individual standard contract, and all the terms of each customized contract.

Staff recommended that PG&E specify to the Commission and staff the parameters it will take into consideration when negotiating the contracts so that all parties will be aware of the factors which be considered in Commission review of the contracts.

TURN argued that the contract review process may engender confidentiality concerns among potential customers who operate in a competitive environment. TURN stated that if any type of formal proceeding is established TURN, and other parties as well, would presumably want to participate causing conflict between customer privacy and procedural due process.

TURN argued that one potential alternative would be to eliminate prior approval, but to include such contracts in the annual reasonableness review. TURN argued that the time lag involved would reduce confidentiality concerns and prevent any negative impacts on negotiations proceeding simultaneously. TURN stated that while there is no easy solution to the problem of securing regulatory review of contract negotiations, this possibility deserves consideration.

PG&E does not want review to be deferred retrospectively to a reasonableness review proceeding because PG&E could be administering contracts for well over half their lives (the contract rate would expire at the end of 1986) before the Commission reviewed them. PG&E argued that if the details of how the contract rate would operate are insufficiently clear, the Commission could nevertheless adopt the contract rate and permit staff and PG&E to work out the details.

We are concerned with the problems associated with staff and Commission review of contracts under G-84. As staff points out, this is essentially a policy question whether the necessary staff resources should be assigned for advance scrutiny of the proposed new contracts. However, we do not believe all anticipated problems will occur, or that problems which do occur will be insurmountable. We will expect PG&E to promptly furnish to our staff for confidential review all G-84 contracts, and that staff will timely inform the Commission of any potential problem associated with the administration of Schedule G-84.

Confidentiality Issues

PG&E requested that the Commission accord G-84 contracts confidential treatment. Staff briefed the legal issues raised by PG&E's request, noting that PU Code § 489 generally provides that all rate schedules and related contracts shall be open to public inspection. However, the staff allowed that the Commission may find it to be in the public interest to maintain the confidentiality of G-84 contracts. Moreover, despite the public policy favoring the publication of a utility's retail rates, PU Code § 583 may require that rate contracts be deemed confidential unless the Commission determines otherwise. PG&E agrees that § 583 permits the confidential treatment of these contracts. This decision will accede to PG&E's request.

Incremental Cost of Gas - G-84

Staff recommends that the contract rate (G-84) be adopted with the provision that the utility impute some price to the long-term value of gas. For example, D.83-12-068, (p. 406) in PG&E's general rate case recommends 12%; SoCal proposed that there be a 5¢/therm premium over the incremental cost of gas in its pending CAM proceeding. Staff believes the PG&E's incremental cost of gas plus some premium (vs incremental cost of gas alone) constitutes the lower end of contract price to be considered while negotiating. The staff stated that such provision would provide greater assurance that contracts signed over a one-year period will not result in a negative contribution to margin.

No one opposed this recommendation. We will adopt the 12% above the incremental cost of gas set forth in D.83-12-068 as a reasonable floor for negotiating contract rates under Schedule G-84.

Curtailment under G-80 and G-82

Under proposed G-80 and G-82 schedules, economic curtailment can take place upon 24 hours' notice. Shorter economic curtailment provision are provided in connection with G-58 and G-59. PG&E's witness indicated in response to staff questioning that PG&E is not opposed to making the period of notice for economic curtailment the same under all rate schedule. Staff recommended that, to the extent a 24-hour curtailment provision is adequate for G-58 and G-59, those schedules be made consistent with G-80 and G-82.

That recommendation is reasonable and is adopted. Schedules G-58 and G-59 should be amended to conform to the 24-hour economic curtailment provisions of Schedules G-80 and G-82.

Priority Provisions
Tariff Rule 21

Staff recommended that PG&E's tariff Rule No. 21 be modified to specifically reflect the priorities of customers on Schedules G-58, G-59, G-80, G-82, and G-84. Staff proposed that P-1 through P-5 remain unchanged, but that P-6 be added. Staff recommended that P-6 include:

P-6A: G-58 and G-80 customers.

P-6B: G-59, G-82, and G-84, as negotiated.

Staff testified that G-84 should have, as an element of negotiation, the priority level of the customer's incremental sales. This rate should be either P-6B, or the customer's nonincremental sales priority.

The staff witness testified that recommendations are consistent with staff recommendations in the current SoCal Gas CAM, (A.84-03-030). The comparable priorities would be:

PG&E	SoCal
P-6A: G-58 and G-80	P-6A: GN-6 (food processors)
P-6B: G-59, G-82, G-84	P-6B: GN-7 (oil recovery)

PG&E proposed that the G-84 contract rate priority be equal to that of the customer's nonincremental usage. TURN argued that the staff recommendation that priority of service be negotiable under the G-84 contract rate provides greater flexibility than PG&E's proposal, appears reasonable to it, and should be adopted.

We will adopt the staff proposal. The priority of service under the G-84 rate should be negotiable as part of the contract. If a higher priority than P6-B is required by a potential customer, that customer probably would negotiate a higher price for gas service to achieve the higher priority, thus providing a greater contribution to margin.

CMA Arguments Re
Incentive Rates

In both its witness's testimony and its brief, CMA stated its position that PG&E's proposed incentive rates will produce undue discrimination and represent an inappropriate response to the problem of declining low priority gas demand.

CMA argued that current gas price and gas supply conditions have invalidated the assumptions underlying alternative fuel based gas pricing policies, and those policies should be replaced. CMA pointed out that PG&E's marginal cost of gas under current supply conditions is below the price of most alternative fossil fuels. CMA stated that it is now appropriate to give low priority users a price signal indicating the declining cost of incremental gas supplies, thus encouraging them to increase their usage of gas and lowering the cost of gas to all customers. CMA also pointed out that there is a continuing trend of lower gas use by low priority customers over the past several years. In order to arrest this trend and to avoid further fuel switching CMA proposed to reduce G-50 and G-58 rates and place all increases on residential and resale customers.

The G-80. G-82, and G-84 schedules are designed to accomplish the regulatory purposes which CMA believes are salutary. However they accomplish those purposes in a manner different from that proposed by CMA.

CMA believes that the G-80, G-82, and G-84 rates are inherently discriminatory because those rates would treat customers similarly situated in a dissimilar manner. Staff argues that the new rate proposals are not inherently discriminatory or unfair although several policy considerations necessarily are involved. We have reviewed the arguments presented by CMA and our staff on this point and conclude that the G-80, G-82, and G-84 are not inherently or unduly discriminatory. The new schedules provide an alternative rate structure to present schedules. The new schedules apply only to incremental usage. All customers who can meet the new requirements may elect whether to stay on current schedules or switch to the new schedules if they would find the new schedule advantageous. Moreover, these incentive rates are a rational attempt to balance continuing conservation goals with the reality of present excess gas supplies and future supply uncertainties.

There appears on this record that no undue discrimination can or will result from the adoption of the new schedules. Moreover, there is a time limit on the schedules, as they expire at the end of 1986; after experience under such schedules, we will permit them to lapse if they do not achieve their purpose.

Adoption of New Schedules

After full consideration of the record and argument, we conclude the proposed new G-80, G-82, and G-84 rate schedules, with the modifications indicated in preceding discussion should be adopted on a trial basis subject to a December 1986 expiration date. We cannot determine on this record the probable customer response to the new innovative schedules. We have no sales in the adopted forecast. Hopefully additional sales will stem or reverse the trend of continued declining sales to low priority customers below forecasted levels, and will produce revenues closer to those estimated in recent GAC proceedings.

Obviously, we are embarking on an experiment involving several unknowns. The auction rate and the contract rate, in particular, raise significant regulatory oversight issues. For example, as more time passes, depending upon our experience in administering Schedule G-84, we might consider imposing limitations on the total volume of gas that PG&E can contract to sell; similarly with experience, we may entertain revisions in the Schedule G-84 review process. We will expect PG&E to cooperate thoroughly with staff to minimize the additional administrative burden we are placing on the staff.

Having made the decision to adopt these experimental rates, we recognize our obligation to deal forthrightly with the problems of implementation and administration which will inevitably arise. On balance, it is our assessment that the experiment, as adopted, is a worthwhile endeavour.

Adopted Summary of Rates
and Revenues

Table 3 on the following page sets forth a summary of rates and revenues for PG&E's gas services which we adopt as reasonable for the purposes of this proceeding.

TABLE NO 3

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

12 MONTHS BEGINNING APR 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)	1383500	.46298	640532	.01203	.47501	657176	2.60
2	Tier II (3)	563485	.70533	397442	.04196	.74729	421086	5.95
3	Total Residential	1946985	.53312	1037974	.02069	.55381	1078262	3.88
	Nonresidential							
4	G-2	1320480	.63761	841951	.02475	.66236	874633	3.88
5	G-50 Block 1	357600	.57105	204207	0	.57105	204207	
6	" Block 2	478088	.54105	258669	0	.54105	258669	
7	" Block 3	35592	.47483	16900	0	.47483	16900	
8	G-50 Total	871280	.55066	479776		.55066	479776	.00
9	G-55A	95940	.54152	51953	0	.54152	51953	.00
10	G-55	2734450	.54152	1480759	0	.54152	1480759	.00
11	G-57	17010	.54152	9211	0	.54152	9211	.00
12	G-58	289620	.47483	137520	0	.47483	137520	.00
13	G-59	146670	.38	55734	0	.38	55734	.00
14	Total Nonresidential	5475450	.55829	3056904		.56426	3089586	1.07
	Resale							
15	G-60 (Palo Alto)	31040	.4259	13219	.00532	.43122	13385	1.26
16	G-61 (Coalinga)	2300	.42605	979	.00512	.43117	991	1.23
17	G-62,G-63 (CPN & SWG)	44200	.42575	18818	.00532	.43107	19053	1.25
18	Total Resale	77540		33016			33429	
19	Total (Gross)	7499975	.55039	4127894		.56017	4201277	1.78
20	GS & GT Adjustment			-7884			-7884	
21	Total (Net)	7499975	.54934	4120010		.55912	4193393	

NOTES

(1) Includes all revenue components
(2) Sales adjusted by 4005 Mth to compensate for G-10 discounts
(3) Present rates effective on May 16, 1984 (G-59 for estimating purposes only)
(4) SAR calculation is net revenue requirement divided by unadjusted sales

Findings of Fact

1. In A.84-03-07. as amended, PG&E requests authority to increase its gas revenues by $82,055,000 annually.

2. The estimates of gas sales, gas takes and gas prices, and the GCBA balance set forth in Table 1 of the preceding opinion are reasonable and should be adopted for the purposes of this proceeding.

3. An annual revenue increase of $73,385,000 is necessary to offset changes in gas sales and gas costs and to amortize the GCBA over a yearly amortization period beginning April 1, 1984.

4. The additional revenue requirement found reasonable here should be distributed to customer classes in accordance with the rate design guidelines set forth in PG&E's last general rate proceeding (D.83-12-068 in A.82-12-48).

5. In applying those guidelines the alternate fuel data submitted in this proceeding indicate that no changes should be made in the rates for industrial and boiler-fuel customers set forth in G-50, G-55, G-57, and G-58.

6. Application of the rate design guidelines to other schedules result in the rates and estimated revenues set forth in Table 3 in the preceding opinion.

7. The rates and resulting estimated revenues set forth in Table 3 will be just and reasonable and should be adopted for the purposes of this proceeding. Increases resulting from the application of such rates are justified.

8. In addition to present schedules, it will be reasonable to adopt new temporary schedules applicable to industrial customers who have switched or have the potential to switch from gas to an alternate fuel. The new schedules, subject to the rules and conditions as more fully described in the opinion, will result is just, reasonable, and nondiscriminatory rates and provisions.

9. The priority system set forth in PG&E's Gas Tariff Rule 21 should be amended as described in the opinion to accommodate the new schedules.

10. Maintaining the confidentiality of G-84 contracts is necessary to the success of the tariff and is thus in the public interest.

Conclusions of Law

1. PG&E should be authorized to increase 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. This order should become effective on the date of issuance because the beginning date of the forecast period of April 1, 1984 has already passed.

4. 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.

5. The adopted new incentive rates for industrial customers (G-80, G-82, and G-84) will not result in undue discrimination, or will otherwise be unlawful.

6. Pursuant to PU Code § 583, G-84 contracts will be accorded confidential treatment.

7. Schedule G-84 rate contracts 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. Five days 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 (including the restrictive language discussed at page 40, supra) and

cancel its presently effective schedules. The revised tariff schedules shall become effective when filed. The revised schedules apply only to service rendered on or after their effective date and shall comply with General Order 96-A, except as discussed in Conclusion of Law 7.

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.

This order is effective today.

Dated AUG 7 1984, at San Francisco, California.

Commissioner Priscilla C. Grew, being necessarily absent, did not participate

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

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

Joseph E. Bodovitz, Executive Director

APPENDIX A

List of Appearances

Applicant: Michael S. Hindus and Robert B. McLennan, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Henry F. Lippitt, II, Attorney at Law, for California Gas Producers Association; William E. Swanson, for Stanford University; Harry K. Winters, for University of California; E. D. Yates, for California League of Food Processors; Downey, Brand, Seymour & Rohwer, by Phillip A. Stohr, Attorney at Law, for General Motors Corporation; Jane Kumin, Attorney at Law, for Natomas Company; W. Randy Baldschun, for the City of Palo Alto; Richard K. Durant and H. Robert Barnes, Attorneys at Law, and Thomas W. Fillmore and Paul M. Sindelar, for Southern California Edison Company; Richard Owen Baish, Attorney at Law (Texas), for El Paso Natural Gas Company; Brobeck, Phleger and Harrison, by Gordon E. Davis, William H. Booth, and Richard E. Harper, Attorneys at Law, and Robert E. Burt, for California Manufacturers Association; Michel Peter Florio and Jon F. Elliott, Attorneys at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Robert G. Steiner, Attorney at Law, for U.S. Borax; Gerald J. La Fave, Attorney at Law, for California Farm Bureau Federation; and Peter N. Osborn and Jeffrey E. Jackson, Attorneys at Law, and F. E. John, T. D. Clarke, and Gey Phillips, for Southern California Gas Company.

Commission Staff: Freda Abbott, Attorney at Law, and John M. Peeples, for the Commission staff.

(END OF APPENDIX A)

TABLE NO 1

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

12 MONTHS BEGINNING APR 1, 1984

GAC REVENUE REQUIREMENT

Line No.	Item	M$
1	Current Cost of Purchased Gas	2922699
2	Plus Gas Cost Balancing Account	224486
3	Plus: Carrying Cost of Prepaid Gas	13066
4	Subtotal	3160251
5	Plus: Adjmt for Fran. & Uncol Acct Exp @ .794 %	25092
6	Plus Base Cost Amount (Includes Test Year 1984)	897260
7	Subtotal	4082603
8	Less: Base & GAC Revenue @ Present Rates (1)	4009218
9	Difference	73385
10	Plus Present Revenue @ Tariff Rates (2)	4170938
11	GAC Revenue Requirement	4244323

(1) Includes Returned Check Revenue

(2) May 16,1984 Effective Commodity Rates

7/06/84

TABLE NO 3

PACIFIC GAS AND ELECTRIC COMPANY

GAS DEPARTMENT

12 MONTHS BEGINNING APR 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 (%)
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2	Tier II	563485	.79571	448370	.02935	.82506	464908	3.69
3	Total Residential	1946985	.55928	1088902	.02113	.58041	1130053	3.78
	Nonresidential							
4	G-2	1320480	.63761	841951	.0241	.66171	873774	3.78
5	G-50 Block 1	357600	.57105	204207	0	.57105	204207	
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7	" Block 3	35592	.47483	16900	0	.47483	16900	
8	G-50 Total	871280	.55066	479776		.55066	479776	.00
9	G-55A	95940	.54152	51953	0	.54152	51953	.00
10	G-55	2734450	.54152	1480759	0	.54152	1480759	.00
11	G-57	17010	.54152	9211	0	.54152	9211	.00
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20	GS & GT Adjustment			-7884			-7884	
21	Total (Net)	7499975	.55613	4170938		.56591	4244325	

NOTES

(1) Includes all revenue components
(2) Sales adjusted by 4005 Mth to compensate for G-10 discounts
(3) Present rates effective on May 16, 1984 (G-59 for estimating purposes only)
(4) SAR calculation is net revenue requirement divided by unadjusted sales

7/25/84

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3. An annual revenue increase of $73,387,000 is necessary to offset changes in gas sales and gas costs and to amortize the GCBA over a yearly amortization period beginning April 1, 1984.

4. The additional revenue requirement found reasonable here should be distributed to customer classes in accordance with the rate design guidelines set forth in PG&E's last general rate proceeding (D.83-12-068 in A.82-12-48).

5. In applying those guidelines the alternate fuel data submitted in this proceeding indicate that no changes should be made in the rates for industrial and boiler-fuel customers set forth in G-50, G-55, G-57, and G-58.

6. Application of the rate design guidelines to other schedules result in the rates and estimated revenues set forth in Table 3 in the preceding opinion.

7. The rates and resulting estimated revenues set forth in Table 3 will be just and reasonable and should be adopted for the purposes of this proceeding. Increases resulting from the application of such rates are justified.

8. In addition to present schedules, it will be reasonable to adopt new temporary schedules applicable to industrial customers who have switched or have the potential to switch from gas to an alternate fuel. The new schedules, subject to the rules and conditions as more fully described in the opinion, will result is just, reasonable, and nondiscriminatory rates and provisions.