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Decision 92-10-051 October 21, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company for Authority to Revise Its Gas Rates and Tariffs Effective April 1, 1992 Pursuant to Decision Nos. 87-12-039, 89-01-040, 89-05-073, 90-04-021, 90-09-089 and 91-05-029. (U 39 G)	Application 91-11-001 (Filed November 1, 1991)

(See Appendix A for appearances.)

INDEX

INDEX

INDEX

INDEX

OPINION

1. Summary

This decision resolves issues raised in Pacific Gas and Electric Company's (PG&E) first biennial cost allocation proceeding (BCAP) for PG&E's natural gas operations. As a result, PG&E's total gas revenue requirement for the two-year BCAP period will decrease by $437.0 million, for an overall 8.4% reduction. This $437.0 million decrease is composed of an $448.6 million reduction in the procurement revenue requirement and a $11.6 million increase in the transportation revenue requirement. The allocation of costs results in total core rates decreasing by $433.6 million or 11.7%, and total noncore rates decreasing by $3.4 million or 0.2%.

We reject a stipulation proposed by five parties due to its (1) allocation of the $5.2 million overcollection in the noncore purchased gas account (PGA) to all noncore customers, (2) adjustment in the throughput forecast for bypass over the Dow Chemical Company (Dow) pipeline, and (3) inclusion of Transwestern Pipeline Company's (Transwestern) contract costs in rates. We order the $5.2 million overcollection in the noncore PGA returned with interest to the noncore customers who paid the overcollection during the period May through July 1991, similar to our treatment of the core-elect PGA refund in Decision (D.) 91-05-029. Without prejudice to any future consideration of this issue, we adjust the throughput forecast to eliminate the forecast of Dow bypass, consistent with Dow's agreement not to serve PG&E customers in D.85-07-029. Finally, we eliminate Transwestern contract costs from rates consistent with D.92-07-025. We accept all other elements of the stipulation.

The contested elements in the proceeding are resolved in the following ways:

- Noncore PGA: PG&E's proposal for its shareholders to receive the $5.2 million overcollection in the noncore PGA is rejected.

- Transwestern: Transwestern demand charges will not be recorded in an interest-bearing memorandum account, but may be booked in PG&E's balancing account consistent with D.92-07-025.

- Discount Adjustment: A routine recalculation of the discount adjustment whenever gas base revenue requirement rate changes are implemented will not be performed.

- Storage Costs: The existing methodology for allocating storage costs is retained.

- Brokerage Fee Balancing Account: The $7.3 million undercollection in the brokerage fee balancing account will be allocated to all noncore customers, including core subscription customers.

- Alternative Fuel Requirement and Noncore Status: The requirement for customers to have an alternate fuel capability to be eligible for noncore status is eliminated, consistent with D.92-03-091. This requirement also eliminates the need for the economic practicality test required of core customers requesting a transfer to noncore status. The penalty for failure to curtail is increased from $1.00 per therm to $16.00 per therm, and customers who show a pattern, or reasonable expectation, of failing to curtail will be moved to the appropriate core rate schedule. Tariff rules will not be modified to include either a specific advance notice requirement or a 24-hour grace period before the penalty applies. The size requirement for noncore status will be set at either 100 Mcf per peak day or 20,800 therms per active month. Existing noncore customers who do not meet this new size requirement, but who earlier had obtained noncore status (e.g., based on alternate fuels), will remain in the noncore class, consistent with D.92-03-091. Implementation of these changes is suspended, however, pending further consideration in the limited scope proceeding in Rulemaking (R.) 86-06-006 ordered in D.92-03-091.

- UEG-Cogeneration Rate Parity: The utility electric generation (UEG)-cogeneration rate parity calculation will include the California Public Utilities Commission (CPUC) fee and exclude UEG igniter fuel.

- Noncore Peaking Rate: A new noncore peaking rate will not be ordered.

- Minimum Average Rate Limiter (MARL): The MARL will be applied to Schedules GS and GSL (master-metered apartment building customers who submeter to their tenants). The MARL will neither be expanded, as proposed by PG&E, nor eliminated, as proposed by Western Mobilehome Association (WMA). Rather, it will be deferred to PG&E's general rate case, where consideration of the electric MARL is currently pending.

- Wholesale Rates: The method of distributing the wholesale class revenue requirement is revised. The methodology is not changed for the calculation of wholesale core entitlement to the use of PG&E's storage facilities.

Finally, we authorize new rules for core transportation rates to properly match amortization of the core PGA overcollection with rates for customers who switch to (or from) core transport service.

2. Background

The primary purposes of a gas cost allocation proceeding are to estimate the gas revenue requirement for both procurement and transportation, allocate that revenue requirement to the various customer classes, and design rates through which the utility has a reasonable opportunity to collect the revenue requirement. The annual cost allocation proceeding (ACAP) has been replaced by the biennial cost allocation proceeding as a result of D.90-09-089 (37 CPUC 2d 583, 626). PG&E filed this--its first BCAP application--on November 1, 1991, requesting an overall decrease in gas rates of approximately $55.8 million (composed of a $297.0 million procurement cost decrease and a $241.2 million transportation cost increase for the two-year test period proposed to begin on August 1, 1992).

Issues were narrowed and defined as a result of rulings by the assigned administrative law judge (ALJ). A motion was denied to strike PG&E testimony regarding an increase in the penalty from $1 to $25 per therm for a noncore customer who fails to curtail when requested. New cost allocation methods proposed by PG&E in pre-filed direct testimony were struck, consistent with Commission direction established in D.91-12-075 (mimeo. pp. 33-34) to defer major issues to the long-run marginal cost (LRMC) proceeding (Investigation (I.) 86-06-005) and streamline the BCAP. Transwestern contract costs were allowed to be included in the revenue requirement as a "default" or "placeholder" cost for this proceeding. The ALJ noted that the Transwestern cost used in the BCAP decision would specifically be subject to refund based on a reasonableness determination in an appropriate future energy cost adjustment clause (ECAC) proceeding. Moreover, the allocation of Transwestern costs in this BCAP would be superseded by the results of the capacity brokering proceedings (Rulemaking (R.) 88-08-018, R.90-02-008). Finally, it was ruled that storage cost allocation would remain an issue, while storage unbundling and new rate design for storage would be treated in other proceedings (i.e., I.87-03-036, I.86-06-005).

D.91-12-049 adopts a stipulation and settlement in which Southwest Gas Corporation (Southwest) agrees to file its first BCAP coincident with PG&E's current BCAP. This matter was noted at the prehearing conference in this application and a schedule adopted for serving Southwest's testimony. On February 13, 1992, Southwest filed a petition for modification of D.91-12-049, asking that the Commission vacate the filing requirement for Southwest's initial BCAP and formally order Southwest to file its initial BCAP application at the same time as PG&E's next BCAP (in about two years). Also, on February 13, Southwest filed a motion to suspend the serving of its testimony, pending a Commission decision on its petition for modification. Southwest's motion was granted.

Evidentiary hearings were held on PG&E's application beginning March 9, 1992. No objections were raised to a motion to shorten the notice requirement for a stipulation conference (Commission Rules of Practice and Procedure, Rules 51.1(b) and 51.6(c)) and the motion was granted (Reporter's Transcript (Tr.) 1:36). The conference was held March 13, 1992. A stipulation between five parties was distributed on March 19, 1992. No objections were raised to a motion to modify the schedule for consideration of the stipulation (Rule 51.6) and the motion was granted (Tr. 1:9, 5:350; 6:534). The goals of the settlement rules were met, even though the procedure differed from that outlined in Rule 51.6. At hearing, parties' original testimony was received as evidence, as was the testimony in support of the stipulation.[1] Hearings on the stipulation began March 24, 1992. Opening and reply briefs were filed. Motions raised after the filing of reply briefs were resolved by ALJ ruling. We affirm the rulings of the ALJ.

Comments and reply comments were received on the proposed decision of the ALJ. Dow filed a motion for leave to file comments. No objections were received. Dow's motion is granted.

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1 We refer to each party's original position by that party's name, and that of the stipulating parties' position as the stipulating parties.

Luz Solar Partners III through VII (Solar Partners) filed a petition to intervene, noting that its interests had been represented by Luz Partnership Management (Luz) but Luz has declared bankruptcy. No objections were received to Solar Partners' petition and it is granted. Southwest filed a motion to file its comments one day late. No objections were received. Southwest's motion is granted. PG&E filed a motion for leave to file reply comments to the comments of Dow. PG&E's motion is granted.

On October 6, 1992 the assigned commissioner directed PG&E to provide the most recent recorded account balances for consideration in preparation of the final decision. PG&E provided that information, marked as Exhibit 36. Parties were given 6 days to comment. No party objected to the receipt of Exhibit 36, and it is received into evidence.

The Division of Ratepayer Advocates (DRA) filed a motion for late receipt of its comments on Exhibit 36. DRA's motion is granted. PG&E filed a motion to accept late-filed comments and comments supporting the comments of DRA on Exhibit 36. PG&E's motion is granted.

We have carefully reviewed the ALJ's proposed decision, along with the comments, reply comments, and updated information. We have ignored comments which reargue positions taken in briefs, consistent with Rule 77.3. We incorporate changes in this decision to reflect the comments which have merit, and the updated data, as explained below.

3. Stipulation

Five parties entered into a stipulation to resolve between themselves many of the issues in this proceeding. These parties are PG&E, DRA, Toward Utility Rate Normalization (TURN), Southwest, and WMA (referred to herein as stipulating parties).

The stipulation resolves most of the issues in dispute between these five parties, as well as several other issues. The stipulation is attached for reference as Appendix B.

Attachment A to the stipulation identifies 16 issues in seven categories not resolved by the stipulation. The stipulation excludes several issues that were of interest to other parties so that they could be addressed in the hearing process, according to the stipulating parties. Nonetheless, the stipulation resolves some items contested by other parties. Despite its resolution of issues contested by nonstipulating parties, the stipulation provides that:

> "Unless the Commission accepts this Stipulation and the recommendations it contains in their entirety, without change or condition, the Parties agree that the Stipulation shall be null and void." (Stipulation, p. 12.)

We do not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest. (Rule 51.1(e).) We have acknowledged in prior decisions the strong California public policy favoring settlement and the propriety of settlement in utility matters. (D.88-12-083, 30 CPUC 2d 189, 221-223; D.91-05-029, mimeo. p. 42.) If the public policy goal is truly to encourage settlements or stipulations, then we must resist the temptation to alter the results of a good faith negotiation process unless the public will be harmed by the agreement. Otherwise, parties will legitimately grow wary of our settlement process. Substituting our judgment for that of the parties is only appropriate if the public interest is in jeopardy. (D.91-05-029, mimeo. p. 42.)

Despite public policy favoring settlements, the burden of proof does not shift from the parties to the Commission. That is, the burden remains with the parties advancing a stipulation or settlement to show that it is reasonable, consistent with law, and in the public interest. The burden is not on the Commission to accept a stipulation or settlement unless the Commission finds it fails one or more of our standards.

Nonstipulating parties contest four elements of the stipulation: (1) allocation of storage costs, (2) allocation of the $7.3 million undercollection in the brokerage fee balancing account, (3) allocation of the $5.2 million overcollection in the noncore PGA, and (4) inclusion of Transwestern demand charges in rates. While we find the stipulation reasonable on nearly every element, we are not able to accept the stipulation's treatment of the allocation of the $5.2 million overcollection in the noncore PGA, nor the inclusion of Transwestern demand costs. Moreover, even though not disputed by nonstipulating parties, we do not accept the stipulation's throughput forecast including Dow pipeline bypass.

The stipulation's treatment of Dow bypass and Transwestern conflict with D.85-07-029 and D.92-07-025, respectively. The stipulation's allocation of the noncore PGA overcollection is unfair to those who purchased the gas and differs from our treatment of a similar overcollection in the core-elect PGA in D.91-05-029. The stipulation is therefore incompatible with the public interest. We discuss these three items in more detail below.

We are also troubled by the stipulation's treatment of some contested issues (e.g., storage; brokerage fee balancing account) while claiming to leave the contested issues to the hearing. Due to this confusion, the California Industrial Group, California Manufacturers Association, and the California League of Food Processors (collectively "CIG") suggest in their opening brief that the stipulation and CIG's proposed storage cost allocation may be simultaneously adopted, or the stipulation may be adopted with modification. DRA's reply brief makes clear that the stipulating parties contemplate no such options.

Parties may stipulate to anything they wish, whether a matter in dispute between themselves or not. The stipulating parties demonstrated fair play by essentially not stipulating to most issues in contention by other parties. Nonetheless, they did stipulate to at least one issue not in contention between themselves, but in contention by other parties. This might have been to leverage the outcome, if on balance the Commission was not entirely pleased with the stipulation's resolution of this issue but did not wish to reject the entire stipulation. As it turns out, our analysis of the storage and brokerage fee balancing account issues leads us to adopt the same result as contained in the stipulation. Nevertheless, we are troubled by a stipulation alleging it leaves disputed issues to hearing when it does not. We encourage future stipulating parties to immediately make clear whether or not they are stipulating to matters not in contention among themselves but which are in contention by other parties.

The stipulating parties differ on what the Commission can do with the remainder of the stipulation. At hearing there seemed to be some interest in the Commission considering as much of the remainder of the stipulation as possible. (Tr. 8:575-80.) In their briefs, however, stipulating parties make clear that they recommend the stipulation be treated in its entirety. For example, DRA states:

> "As stated in the Stipulation, it was negotiated as a whole package and agreed to as a whole package. Each party gave up certain advantages to gain other advantages. Alteration of any part of the settlement upsets the balance struck during the negotiations. Were the Commission to pick and choose among parts of the stipulation, adopting some and rejecting others, ...it would void the stipulation leaving no agreement among the parties as to the resolution of the issues in this case. (Stipulation at 12.)" (Opening brief of DRA, p. 4.)

Being unable to adopt three items of the stipulation, we are left no choice but to reject the entire stipulation.

DRA cautions the Commission:

> "In considering the stipulation, the Commission should keep in mind that the record in this proceeding was shaped by the stipulation. In keeping with the purpose of settling the issues in the case, the stipulating parties agreed not to cross examine each other's witnesses on issues resolved by stipulation. (Stipulation at 11.) This means that the positions taken in testimony by stipulating parties on issues subsequently resolved by stipulation have not been tested by cross examination." (DRA opening brief, p. 3.)

Rule 51.7 provides that upon rejection of a stipulation we may take various steps. Those steps include holding hearings, letting parties renegotiate, or proposing alternative terms for the parties' consideration. We may also make a decision based on the record. While we understand the stipulating parties elected not to cross-examine each other, all the original testimony was received into evidence. We believe the record is substantial and ripe for decision. As explained below, our independent assessment of the many items resolved in the stipulation leads us to adopt the stipulation's results on all items except the three items identified above.

Having rejected the stipulation, we now turn to address each of the elements in this proceeding.

4. Economic Activity, Oil Prices, Alternate Fuel Prices

Economic activity and oil price forecasts are used in forecasting throughput. Oil prices are also used to forecast the price of alternate fuels, which in turn are used to forecast the amount of discounting necessary to retain noncore transportation customers.

PG&E and DRA are the only parties that took a position on economic forecasting. DRA accepted PG&E's forecast. We adopt PG&E's forecast.

PG&E's petroleum product price forecasts for crude oil and alternate fuels are reasonable, according to DRA. No other party disputed these forecasts. We adopt PG&E's forecasts. (See Appendix C.)

5. Gas Throughput

Gas throughput is defined as gas demand minus gas curtailments. Curtailment of gas service occurs when demand cannot be fully served due to supply or capacity limitations. The gas throughput forecasts are an essential part of the BCAP, for both cost allocation and rate design.

5.1 Core

5.1.1 Residential and Commercial

PG&E forecast residential throughput to be 207.3 and 209.1 MMdth for the first and second years of the BCAP test period, respectively, and commercial throughput to be 91.3 and 93.5 MMdth for the first and second years, respectively. DRA forecast residential throughput to be 209.7 and 221.2 MMdth for the first and second year of the BCAP test period, respectively, and commercial throughput to be 99.4 and 104.7 MMdth for the first and second years, respectively. DRA's forecasts exceed those of PG&E in large part due to DRA's forecast of a lower gas price. As we discuss below, we adopt a gas price approximately halfway between PG&E's and DRA's original estimates. We therefore adopt throughput estimates which reflect our adopted gas price. We adopt a residential throughput forecast of 208.5 and 215.2 MMdth for the first and second years, respectively. We adopt a commercial throughput estimate of 95.3 and 99.1 MMdth for the two years, respectively. (See Appendix D.)

5.1.2 Core Interdepartmental, PG&E UEG Igniter Fuel, and Natural Gas Vehicles (NGV)

Core interdepartmental, PG&E UEG igniter fuel and NGV throughput comprise approximately 0.5% of total core throughput, a relatively small share. DRA specifically adopts PG&E's estimate of NGV throughput, and does not itemize a difference on core interdepartmental and PG&E UEG igniter fuel. We find PG&E's estimates reasonable. We adopt 0.2 MMdth for each year of the test period for core interdepartmental throughput, 1.3 MMdth and 1.4 MMdth for PG&E UEG igniter fuel, and 0.1 and 0.2 MMdth for NGV, for the two years. (See Appendix D.)

5.2 Noncore

5.2.1 Industrial

PG&E forecasts industrial gas demand as a function of industrial economic growth, natural gas prices, and alternate fuel prices. PG&E's ability to negotiate individual contracts with industrial customers leads PG&E to forecast minimal amounts of fuel switching from gas to oil. Given minimal price-induced variations in demand, PG&E forecasts growth in industrial gas demand at approximately the same rate as the growth in the economy, measured by industrial production growth.

DRA develops an econometric model to forecast industrial gas demand, including gas and oil prices as variables. DRA also adjusts its forecast for an error made by PG&E in calculating the cogeneration backout estimate. PG&E agrees with DRA's adjustment.

While both PG&E and DRA forecast reduced industrial demand in both BCAP periods compared to 1990 recorded levels, DRA's forecast exceeds PG&E's by 2.8% in the first BCAP year and 7.0% in the second BCAP year. These forecasts exclude cogeneration and industrial bypass volumes which are addressed separately.

TURN supports DRA's forecast. TURN suggests that if PG&E's forecast is used it should be increased by 4.8 MMdth per year to reflect the potential for some customer loads to return to gas use after having previously switched to various alternate fuels.

Our adopted gas price forecast reduces the difference between PG&E's and DRA's industrial throughput forecast. We adopt PG&E's estimate of industrial throughput modified to reflect the recalculation of the cogeneration backout. We also adjust the industrial throughput to include 4.8 MMdth as recommended by TURN. This reasonably includes customer loads switching back to natural gas without overestimating the impact by assuming more price-induced conversion than likely given the already large proportionate use of gas.

5.2.2 SCE Cool Water

PG&E originally estimated Southern California Edison Company's (SCE) gas demand for its Cool Water plant based on a forecast developed by SCE in the Southern California Gas Company (SoCal) BCAP proceeding (Application (A.) 91-03-034). DRA notes that SCE provided DRA five gas supply alternatives for the Cool Water plant. These alternatives demonstrate that bypassing PG&E's system may be attractive. In rebuttal testimony, PG&E eliminated its estimated sales to SCE's Cool Water plant, assuming total bypass of PG&E's system.

Total bypass is not certain. We adopt a throughput forecast of 2 MMdth for each year to the Cool Water facility. This incorporates a conservative approach by assuming that some incremental throughput to Cool Water from PG&E will occur.

5.2.3 Cogeneration

DRA accepts PG&E's forecasting methodology for cogeneration as reasonable. The primary difference in results between DRA and PG&E cogeneration forecasts is PG&E's inadvertent exclusion of gas demand for one cogeneration project during the months of January, February, and March of 1992 and 1993. We adopt PG&E's forecast of cogeneration throughput adjusted for this project as recommended by DRA.

5.2.4 Enhanced Oil Recovery (EOR), Industrial Interdepartmental, and Steam Heat

DRA accepts PG&E's EOR forecast and forecasting methodology, and no dispute surfaces regarding the relatively small forecast for industrial interdepartmental and steam heat. No other party developed a throughput forecast for these customers. We adopt PG&E's estimate for these customers.

5.2.5 UEG

PG&E's electric department is one of its gas department's largest single customers, accounting for approximately 25% of total gas throughput. Both DRA and PG&E utilized a production cost model to forecast UEG throughput. PG&E used the input assumptions it filed in its 1991 ECAC proceeding (A.91-04-003), which were the latest available when it filed this BCAP. DRA used resource assumptions adopted in D.91-11-056 (A.91-04-003). Both the PG&E and DRA forecasts assume 14.6 MMdth per year bypass by PG&E's electric department of PG&E's gas department.

TURN testifies that this bypass is both uncertain and poor policy. TURN identifies the facility involved as the Shell/Steelhead system. TURN argues that the entire project is speculative. Finally, TURN contends that unless this project can be shown to represent economic bypass (in which case PG&E should probably consider buying the pipeline itself), the prospect of PG&E bypassing its own system is extremely troubling.

TURN recommends that we reject the proposed bypass and add 14.6 MMdth back into the forecast of PG&E's UEG demand. TURN also recommends that PG&E be directed to file a separate application with the full details of the transaction before it enters into any self-bypass ventures.

The stipulation recommends no UEG bypass in the throughput estimate. It also contains certain ratemaking provisions.

We adopt DRA's UEG demand estimate, since it is based on resouce assumptions adopted in D.91-11-056, but we make an adjustment to reject UEG bypass. Appendix D shows our adopted UEG forecast, including monthly volumes per D.92-05-022. UEG bypass is not now occurring. It is reasonable to adopt a UEG forecast that reflects the current status. Moreover, we do not wish to prejudge whether this bypass should or should not occur. We note that reasonableness determinations are made in ECAC proceedings. Since PG&E raised this issue in this BCAP--and in its original testimony requested that the Commission recognize a not insignificant amount of incremental UEG bypass--we specifically direct PG&E to justify its decision(s) to either bypass or not bypass some portion of its

UEG load in the future ECACs which cover the record periods from August 1, 1992 through July 30, 1994. We address other elements of UEG bypass below.

5.2.6 Wholesale

Both PG&E and DRA forecast wholesale throughput to be 15.6 and 16.3 MMdth for the two years of the test period. Southwest testified that the PG&E and DRA forecasts should be reduced because of the bankruptcy of Luz International Limited. Southwest also testified that PG&E's wholesale estimate may be overstated because of potential Southwest bypass of PG&E, with Southwest obtaining some service from SoCal.

We adopt the PG&E forecast of wholesale throughput adjusted to reflect the effects of the Luz bankruptcy. We do not forecast any reduced sales to Southwest. We address Southwest bypass further below.

5.2.7 Dow Pipeline

PG&E reduces its forecast of industrial and cogeneration throughput by 8.9 MMdth per year to reflect PG&E customers served by the Dow pipeline. DRA accepts PG&E's forecast of this bypass.

TURN recommends that PG&E's industrial and cogeneration demand forecasts be increased by 5.2 MMdth and 3.7 MMdth, respectively, to remove the effect of the assumed Dow bypass. TURN further recommends a Commission investigation to ascertain whether service is being provided without proper Commission authorization. In support, TURN cites D.85-07-029. In that matter, PG&E filed a complaint in 1985 seeking an order that Dow and its subsidiary, Great Western Pipeline Company, Inc. (Great Western), cease and desist from serving other end-use customers over its pipeline system without first obtaining a certificate of public convenience and necessity (CPCN) authorizing such service. That litigation ultimately resulted in a settlement, approved in D.85-07-029, in which Great Western agreed to terminate its sales to other PG&E customers and pay PG&E $1 million (to be credited to ratepayers to offset a portion of PG&E's lost margin contribution resulting from the bypass). Dow and its affiliate also agreed that before they engage in any future retail sales activity they would either obtain a CPCN or an order stating that the proposed actions are not subject to Commission jurisdiction.

TURN testifies that it is not aware of any attempt by Dow to obtain a CPCN, nor a declaration of nonjurisdiction. TURN states it does not understand why PG&E has not taken action, as it did in 1985, to prevent this bypass, unless PG&E itself is attempting to work out a service agreement with Dow for direct bypass to one of its own power plants. TURN asserts adoption of PG&E's proposed adjustment would effectively shift the entire risk of revenue loss to ratepayers, leaving PG&E--the party in the best position to take action--with no direct financial responsibility for the revenue loss that it has apparently tolerated.

In rebuttal, PG&E argues TURN presents no evidence that the bypass is not occurring, will not continue, or that PG&E is capable of preventing the bypass. PG&E also contends that it is inappropriate to adjust the throughput since the BCAP is a forecast proceeding.

Stipulating parties recommend a throughput forecast which reflects existing conditions, thereby reducing throughput to reflect Dow bypass. PG&E agrees to file a Commission complaint against Dow as a term of the stipulation, along with agreeing to certain ratemaking provisions.

Forecasting Dow bypass is inconsistent with D.85-07-029. We add 5.2 MMdth and 3.7 MMdth back into PG&E's industrial and cogeneration demand forecasts, respectively, to remove the effect of the assumed Dow bypass. We correct an error in the proposed decision so that sales are added back in the reverse of PG&E's exclusion. This correction also treats these as predominantly transport rather than procurement sales.

PG&E comments that including these sales gives PG&E the wrong incentive and penalizes PG&E even though its actions are prudent. As we direct below, PG&E will file a report in its next ECAC justifying whatever action PG&E takes or does not take with regard to the Dow bypass. If the treatment we adopt here results in a penalty that PG&E successfully argues in the ECAC is incorrect, we will reverse any improper penalty.

Dow contends that its actions do not violate the settlement which underlies D.85-07-029, while inclusion of these sales as PG&E's will prejudge issues which may eventually come before the Commission. We disagree. The evidence in this record supports rejection of the reduction in throughput for Dow bypass. At the same time, however, we specifically state that by this treatment we are not prejudging the outcome in any future ECAC review (see below), a complaint that may be filed by PG&E (see below), or anything else that may come before us on this issue. This treatment is consistent with the prior Commission decision, it properly allocates the risk, and it provides PG&E with an incentive to resolve this matter. We address other aspects of the stipulation's treatment of Dow bypass below.

5.3 Shrinkage

PG&E forecasts gas department use plus lost and unaccounted for gas in the category of shrinkage. No party challenged PG&E's estimates. We adopt PG&E's estimates.

5.4 Cold Year Throughput and Curtailments

Cold year throughput may differ from average year throughput for two reasons: (1) cold year conditions or (2) different curtailments. We adopt cold year demand forecasts that are consistent with the average year demand forecasts determined above.

PG&E estimates 11.1 MMdth of curtailments for the first year of the BCAP test period. Neither DRA nor TURN proposes an alternative estimate. TURN points out, however, that curtailments are carried out on an economic basis. According to TURN, the customer paying the lowest percent of the default rate is curtailed first, not the customer paying the lowest total rate. Because Cool Water pays a lower percentage of the default rate than UEG, TURN recommends that at least 1.2 MMdth per year of service to Cool

Water at a discounted rate be curtailed prior to PG&E's own UEG. This impacts rates in this BCAP because the other PG&E customers are allocated the dollars UEG would have paid if it were not curtailed.

We adopt PG&E's estimate. This curtailment is allocated to UEG, with a small portion to EOR. This is reasonable in light of the fact that a relatively small throughput is estimated to Cool Water, only a small component of which would occur in the winter months when curtailments typically occur.

6. Ratemaking Provisions for Bypass

PG&E forecasts significant amounts of incremental bypass (over 98 MMdth per year), including bypass associated with Cool Water, Dow pipeline, and UEG. Throughput forecasts adopted in this decision include bypass by Cool Water (except for 2 MMdth per year), and reject bypass estimates for Dow pipeline, UEG, and Southwest. The proposed stipulation creates special ratemaking provisions for dealing with Dow, UEG, and Southwest bypass.

6.1 Dow Pipeline

The stipulation contains a throughput estimate which assumes Dow bypass, with concurrent revenues losses. The stipulation provides that the additional revenues received by PG&E if the Dow bypass completely ceases to occur will be tracked and returned to all customers based on cold year throughput. We adopt a throughput forecast which rejects the estimates of Dow bypass, and therefore no special tracking or ratemaking treatment need be made.

The stipulation also provides that PG&E will file a complaint at the Commission against Dow, alleging that Dow's actions constitute a business affected with the public interest and impressed with a public use. By rejection of the stipulation, PG&E is relieved of this obligation. We will not direct PG&E to file a complaint, but we strongly encourage PG&E to pursue appropriate relief on behalf of its ratepayers. We will direct PG&E to file a report in its next ECAC proceeding justifying whatever action PG&E takes or does not take with regard to the Dow bypass.

6.2 UEG

The proposed stipulation provides that PG&E will file an application requesting Commission authorization before beginning any UEG bypass. Further, the proposed stipulation provides that if the Commission authorizes UEG bypass, the UEG monthly total demand charges will be reduced, with the undercollection recorded in a balancing account to be recovered in PG&E's next BCAP from all ratepayers based on cold year throughput. By our rejection of the stipulation, neither PG&E nor the Commission is bound by these provisions.

While PG&E is relieved of its obligation to file an application before its electric department bypasses its gas system, nothing in our rejection of the stipulation prohibits PG&E from filing if it wishes to do so. In fact, PG&E filed A.92-07-049 on July 28, 1992, which proposes the establishment of an expedited approval process for discounted long-term competitive gas contracts, including those to UEG. That proceeding will address whatever balancing account and ratemaking provisions may be necessary. Similarly, PG&E may file another application to address any other terms or conditions of UEG bypass outside the scope of A.92-07-049, to the extent necessary. But, just as with Dow bypass, no special balancing account or ratemaking treatment need be made here, since our throughput forecast rejects bypass.

We understand the stipulating parties' argument that UEG bypass involves policy issues better considered on a prospective rather than retrospective basis. As TURN points out, PG&E is effectively foreclosed from bypassing its gas department unless it obtains a reduction in UEG demand charges. Thus, we are reasonably confident that PG&E will seek Commission review before engaging in bypass of its gas department, such as in A.92-07-049 or a similar application. Moreover, we have directed PG&E to file a report in its next ECAC application justifying its decision to either proceed or not proceed with UEG bypass.

6.3 Southwest

Southwest currently receives the majority of its requirements from PG&E, with the remaining volumes delivered by SoCal under an interutility exchange agreement between PG&E and SoCal. Southwest's current service agreement with PG&E terminates in April 1993. Southwest testifies that it is exploring the possibility of discontinuing its historical full requirements service relationship with PG&E and alternatively subscribing for service from both utilities directly. To facilite Southwest's options, Southwest recommends that PG&E's demand charge under schedule G-WRT be eliminated and the revenues recovered through a volumetric rate.

PG&E opposes Southwest's recommendations. PG&E argues that SoCal has not given PG&E notice of termination as required by its interutility agreement with PG&E. Further, PG&E asserts that the demand charge is justified since PG&E must include Southwest core volume in its system planning requirements.

The stipulation provides that Southwest will not bypass PG&E service during the BCAP period unless it first files an application with the Commission seeking authorization to do so. It further provides that if the Commission authorizes Southwest's bypass, then PG&E's demand charges to Southwest will be appropriately reduced, with the undercollection recorded in a balancing account to be recovered from all customers based on cold year throughput in PG&E's next BCAP.

Our rejecting the stipulation means that Southwest is not bound by the provision to file an application before bypassing PG&E's service. Nothing in our rejection of this stipulation, however, prevents Southwest from filing for such relief. This relief would procedurally need to be sought by complaint since customers are not eligible to file applications (and Southwest is a customer of PG&E in this situation).

Moreover, we are convinced by PG&E not to redesign schedule G-WRT to an all-volumetric rate (at least pending review in a complaint Southwest may file). This effectively forecloses Southwest from discontinuing PG&E service during the test period unless Southwest files a complaint which would produce that result and the complainant's requested relief is granted. Further, if Southwest elects to file a complaint, it may in that filing include the other ratemaking provisions contained in the stipulation (or PG&E may raise these provisions in its response to the complaint). This will allow us to consider on a prospective basis the merits of Southwest bypass and its impacts on PG&E, SoCal, and Southwest. Since we assume no Southwest bypass in this BCAP, we need not make other ratemaking provisions.

Southwest comments that this treatment harms Southwest ratepayers by establishing regulatory and procedural barriers to Southwest's taking advantage of competition between PG&E, SoCal, and others. To the contrary, our treatment parallels that in the stipulation. Southwest's reading of the stipulation differs from ours if Southwest believes the stipulation would have allowed reduced demand charges and bypass while an application is pending. Southwest, however, may seek whatever relief is appropriate in a complaint.

7. WACOG and Procurement Rates

7.1 WACOG

The natural gas purchased by PG&E is aggregated into a single portfolio. An estimate of the portfolio's weighted average cost of gas (WACOG) is an important element of the BCAP, being used to develop the commodity component of core rates and the total procurement revenue requirement. It is also used to estimate the amount of necessary discounting to noncore customers. The WACOG does not include franchise fees and uncollectible accounts expense, brokerage fees, procurement balancing account amounts, or shrinkage.

The table below summarizes the recommendations of the parties making a WACOG forecast.

Line No.	Party	WACOG BCAP1 ($/dth)	WACOG BCAP 2 ($/dth)
1	PG&E Direct Testimony	2.00	2.05
2	DRA	1.65	1.70
3	TURN	1.765	1.765
4	PG&E Rebuttal Testimony	1.88	1.92
5	Stipulation	1.825	1.825

BCAP1 = August 1, 1992 - July 31, 1993
BCAP2 = August 1, 1993 - July 31, 1994

The differences in the recommended WACOG are significant. The estimated procurement revenue requirement over the two-year BCAP period is approximately $300 million (16%) less using DRA's WACOG compared to PG&E's original WACOG.

In developing its WACOG, each party makes assumptions concerning the price of natural gas from Canada, the U.S. Southwest, and California. PG&E's price forecast is based on the assumption that the U.S. Southwest tends to be the price leader for Canadian and California suppliers. In contrast, DRA assumes greater competition between regions. DRA estimates lower spot prices from both Canada and the U.S. Southwest than does PG&E. In addition, DRA does not attach any reliability premiums to its price forecast of long-term supplies.

TURN recommends that we continue to use the 'rates in effect' approach that was adopted with minor modification in PG&E's 1990 ACAP decision (D.90-04-021, 36 CPUC 2d 148, 201). TURN notes that last year's ACAP was settled, so no specific methodology was approved by the Commission in that proceeding.

In rebuttal testimony, PG&E recommends using a rates in effect approach for Canadian gas prices because of the uncertainties related to the outcome of the ongoing efforts to restructure PG&E's Canadian gas arrangements. PG&E revises its forecasted WACOG accordingly. The stipulating parties recommend a WACOG of $1.825 per decatherm, without necessarily agreeing on the underlying components of the forecast.

Our rejection of the stipulation requires that we make a decision based on the competing testimony. After considering all the factors, we adopt an estimated WACOG of $1.825 per decatherm for the two-year BCAP period. This WACOG is not a forecast but continues the rates in effect approach from D.90-04-021 (32 CPUC 2d 148, 201). We embed in this WACOG no judgments on the success of our restructuring efforts with Canada. We are hopeful, nonetheless, of improvements in the gas market which will make the $1.825 per decatherm a conservative estimate. To the extent we are successful, ratepayers will benefit in the next BCAP by a core PGA overcollection.

7.2 Procurement Rates

PG&E provides procurement service under two separate rates. Core customers receive procurement service as part of the bundled natural gas rate. Noncore procurement customers purchase gas from PG&E under PG&E's core subscription rate. Only the core procurement rate is actually established in the BCAP. The core subscription rate is calculated monthly, based on the actual WACOG lagged one month.

Procurement rates are determined by calculating the cost of gas, allocating the PGA balancing account balances, allocating the brokerage fee revenue requirement, and calculating the franchise fee and uncollectible revenue requirement. In addition, we include shrinkage costs, consistent with our decision below to include future shrinkage costs for PG&E's procurement customers (those incurred after the implementation of rates from this proceeding) as a cost of gas in the PGA. This approach is consistent with the methods adopted in previous cost allocation proceedings, with the addition of shrinkage costs. Appendix E shows the resulting procurement rates.

8. Revenue Requirement

The total revenue requirement is the amount for which PG&E requests recovery from customers during the two-year BCAP period. The total revenue requirement is composed of the procurement revenue requirement and the transportation revenue requirement. The procurement revenue requirement includes components related to gas costs in the gas supply portfolio, the brokerage fee revenue requirement, procurement balancing account balances, franchise fees and uncollectible accounts expense, and, as discussed below, future shrinkage costs. The transportation revenue requirement includes forecast expenses and balancing account balances for transportation, including Transwestern pipeline demand charges should they be allowed. After considering all the evidence, we adopt the methods for developing the revenue requirement outlined in PG&E's prepared testimony except as expressly noted herein. The adopted revenue requirement is shown in Appendix F.

8.1 Noncore Shrinkage Tracking Account

8.1.1 Current Noncore Shrinkage Tracking Account Balance

PG&E recommends that the shrinkage subaccount of the core fixed cost account be combined into the core subaccount of the PGA, and that the core subscription shrinkage tracking account be combined into the core subscription subaccount of the PGA. DRA does not oppose PG&E's proposed treatment of the shrinkage subaccounts.

TURN, however, objects to PG&E's proposal to recover the $7.0 million balance in the shrinkage tracking account from its core subscription customers. TURN argues PG&E's proposal is directly contrary to Resolution No. G-2948 (May 22, 1991). That resolution rejected PG&E's proposal to transfer shrinkage costs from transportation rates to procurement rates. Rather, it was determined that shrinkage tracking account costs should not receive balancing account treatment. PG&E's recommendation in this BCAP functions like a balancing account for rate recovery purposes, TURN asserts. TURN argues that PG&E's proposal to transfer its shrinkage accounts to the PGA on a prospective basis must be rejected for the same reasons it was rejected in Resolution No. G-2948.

The stipulating parties recommend we treat the $7.0 million balance in the shrinkage tracking account as though the entries had been recorded in the noncore fixed cost account. Even though we reject the stipulation, we adopt this solution on its own merits. Prior to the August 1, 1991, restructuring, shrinkage costs were included in the noncore fixed cost account. Treating the noncore shrinkage tracking account balance as though it had been recorded in the noncore fixed cost account is consistent with the approach last adopted by the Commission and we are not persuaded a change is justified.

8.1.2 Future Shrinkage Costs

Core subscription customers are noncore customers who buy gas from PG&E. PG&E recommends that future core subscription shrinkage tracking account balances be amortized in core subscription rates rather than through the noncore shrinkage tracking account and noncore rates. TURN argues this recommendation is inconsistent with Resolution No. G-2948. TURN asserts PG&E should be at risk for variations between shrinkage costs and shrinkage revenues, at least with respect to the noncore market. TURN claims such risk provides the incentive for the utility to minimize shrinkage volumes. Stipulating parties recommend future shrinkage costs be recorded in the PGA, with PG&E at risk for some of the noncore portion.

We reject the stipulation in total, but we adopt its recommendation regarding future shrinkage costs on its own merits. We direct that future core subscription shrinkage costs for PG&E's procurement customers (those incurred after the implementation of rates for this proceeding) be recorded as a cost of gas in the PGA. This treatment is reasonable because core subscription shrinkage costs are costs of gas bought for those noncore customers who purchase gas from PG&E. Customers who procure their own gas already pay their shrinkage costs by providing shrinkage in kind, and thus should not be forced to bear a portion of the core subscription shrinkage tracking account balance as well.

Further, we direct that PG&E be at risk for the noncore portion of the variation between the recorded shrinkage costs and recorded shrinkage revenues to the same extent it is at risk for the variation in revenues in the noncore fixed cost account.[2] Partial balancing account treatment for future shrinkage costs prevents the utility from bearing the full impact of fluctuations in the noncore shrinkage tracking account. At the same time, however, allowing only partial protection gives PG&E an incentive to minimize shrinkage costs.

8.2 Continued Balancing Account Treatment for the Brokerage Fee Balancing Account

PG&E proposes that balancing account treatment continue for the brokerage fee balancing account. PG&E argues that it should not be at risk for the brokerage cost revenue requirement because such risk provides it with an incentive to sell gas to noncore customers. PG&E asserts balancing account treatment should continue because of the ongoing changes in customer options for noncore procurement, the resulting noncore sales forecast uncertainty and the potential for further regulatory changes during the test period.

DRA testifies that the conditions which led to the authorization of balancing account treatment in PG&E's 1991 ACAP (D.91-05-029) no longer exist. At the time of the last ACAP, DRA contends the most important issue was determining the brokerage fee revenue requirement. D.91-11-050 has now determined, and adopted, an amount for the brokerage fee revenue requirement. DRA quotes D.89-09-094 wherein we state our intention is "to put PG&E at risk

2 Currently, PG&E is at risk for 25% of this variation as of May 15, 1992. (See D.91-05-029, mimeo. p. 41.)

for recovery of brokerage revenues." (32 CPUC 2d 500, 507.) Further, we state that "the implementation of the brokerage fee should make PG&E, not noncore ratepayers, liable for brokerage fee revenues and should promote a competitive market." (32 CPUC 2d 500, 507.) DRA testifies that the intentions stated in D.89-09-094 should now be permanently implemented.

In rebuttal PG&E argues that the Commission has limited the role of utilities in noncore customer procurement since the 1989 decision establishing utility risk for brokerage fees. PG&E testifies that its UEG load is about two-thirds of the forecast core-subscription volume. Thus, PG&E claims UEG is forecast to pay two-thirds of the annual brokerage fee revenue. PG&E testifies that if it is put at risk for brokerage fees, a biased incentive is created for PG&E power plant gas procurement, foreclosing any UEG bypass. PG&E asks that we not create conflicting incentives for the electric department as it examines its gas supply options. Moreover, if put at risk for brokerage fees, PG&E will seek to sell gas to noncore customers in order to fully recover PG&E's costs and contribute to shareholder earnings.

We shall continue the balancing account treatment for the brokerage fee balancing account. Given our actions to limit the role of utilities in noncore customer procurement, we decline to place PG&E in the position where its primary opportunity to fully recover its costs and contribute to earnings is to maximize UEG sales and encourage gas sales to noncore customers. Relatedly, as we discussed as part of UEG bypass above, PG&E must justify in its next ECAC proceeding its decision to either bypass or not bypass UEG.

8.3 Shareholder or Ratepayer Recovery of Overcollection in Noncore PGA

The noncore PGA ended on July 31, 1991 with a $5.2 million overcollection. PG&E recommends this overcollection not be used to reduce revenue requirements. Rather, it should be given to shareholders who, PG&E argues, bore the risk of an undercollection in this account. We reject PG&E's recommendation.

The noncore PGA was established in order to offer noncore customers a utility source for procuring an aggregated short-term gas supply (D.86-12-010, 22 CPUC 2d 491). This account was in effect from May 1988 through July 1991, when it was eliminated as part of the restructuring related to the new procurement rules (D.90-09-089, 37 CPUC 2d 583). On March 26, 1991, before it was known whether the account would ultimately be under- or overcollected but when it was known that the noncore portfolio service would end August 1, 1991, PG&E filed Advice Letter 1624-G-A requesting Commission approval to include the final noncore purchased gas memorandum account balance in the core subscription subaccount of the PGA. By this device, PG&B would shift the risk of the final balance to ratepayers. We denied PG&E's request, deciding instead that the noncore PGA balance should be set aside as of July 31, 1991 for disposition in PG&E's next cost allocation proceeding. (Resolution No. 2948, Conclusions 75 and 76, p. 72.)

The final balance is a $5.2 million overcollection. We are convinced by DRA and Luz that this overcollection should be returned to ratepayers, not shareholders. The policies for noncore portfolio service were established in D.86-12-010 (22 CPUC 2d 491) and clarified in D.87-12-039 (26 CPUC 2d 213). This service was established to provide noncore customers with the option of a short-term, month-to-month, best efforts supply of spot gas. Generally, we have not allowed gas utilities to profit from any of their noncore procurement activities. As we said in D.86-12-010:

> "Finally, we reconfirm the proposal in the OIR that utilities should not realize any margin contribution or opportunity for profit through gas procurement rates at this time." (22 CPUC 2d 491, 520.)

> "Utilities should not profit from gas sales at this time." (22 CPUC 2d 491, 565, Conclusion of Law 28.)

As a result, we required the utilities to establish cost-based tariffs for service from the noncore portfolio, and to charge noncore portfolio customers the noncore portfolio WACOG. We subsequently considered but rejected proposals to allow utilities to charge procurement prices based on what the market would bear. We clarified in D.87-12-039 (26 CPUC 2d 213) that utilities could adjust the noncore portfolio WACOG only to true-up inaccuracies in the prior months' WACOG estimates. This allowed gas utilities to amortize under- or overcollections in their noncore PGA accounts and thus to minimize the balance in the account. The utility was not allowed to profit if, for example, in a particular month the sum of its spot gas WACOG plus the adjustment from prior months was less than the overall market price which could have been charged.

PG&E shareholders were at no risk from the noncore PGA as long as PG&E provided a service which reasonably met the Commission's policy of offering a cost-based, best efforts portfolio of spot gas supplies. PG&E shareholders were not meant to profit from noncore portfolio sales, nor were they meant to lose if the noncore portfolio final balance was undercollected.

Despite PG&E's attempt in Advice Letter 1624-G-A to shift the risk of the final balance ratemaking treatment from shareholders to ratepayers, PG&E now argues that shareholders have borne all of the risk of under- or overcollection of the account since its inception. In support, PG&E cites the Preliminary Statement defining the term "memorandum account" in effect at the time the Noncore Purchased Gas Memorandum Account was established: "...the stockholder is at risk for the resulting under- or overcollection." (Cal. P.U.C. Sheet No. 12995-G, paragraph C.18.) We note that subsequent Preliminary Statements treat the definition of memorandum account differently. For example, effective May 20, 1991, the definition indicates that the shareholder "may be" rather than "is" at risk for the resulting under- or overcollection. The Preliminary Statement effective August 1, 1991 indicates that

"...the under- or overcollection may or may not be amortized in future years." While this latter definition of memorandum account was not effective until after the termination of the noncore PGA memorandum account, PG&E's witness testified that the changes in these definitions were not intended to reflect any changes in ratemaking treatment. Nor, contrary to PG&E's assertion, do they make it clear whether shareholders or ratepayers will ultimately be responsible for any undercollection or overcollection. (Tr. 2:76.)

In September 1990, we announced that the noncore portfolio service would end on August 1, 1991. (D.90-09-089, 37 CPUC 2d 583.) The experience with the balance in the account since its inception in May 1988, and particularly from September 1990 through July 1991, is particularly informative with regard to possible PG&E shareholder risk. The noncore PGA balance varied between positive and negative amounts, with revenues exceeding expenses in some months and not in others. In each and every one of the ten months after D.90-09-089, however, PG&E overcollected from its noncore portfolio customers. A $4.2 million cumulative undercollection in the noncore PGA in September 1990 was converted into a $5.2 million overcollection when the account was terminated, and final entries booked.

Given the uncertainty whether the final balance would accrue to shareholders or ratepayers, and PG&E's incentive not to lose money for shareholders, we conclude that PG&E systematically sought to bring the noncore PGA balance to zero. Indeed, this is consistent with the way we intended the noncore PGA to operate. That is, PG&E was authorized to reset the prices up to twice a month. (D.86-12-010, 22 CPUC 2d 491, 541.) Any undercollection (overcollection) was to be recovered (returned) as prices were reset. Monthly revenues exceeded expenses every month after our decision to terminate the noncore PGA. This indicates PG&E's ability to control the balance in the account, consistent with our expectation for PG&E's administration of this account. Given the way we intended the noncore PGA to operate and PG&E's ability to carry out our intent, it cannot be said that PG&E shareholders bore the risk for the final noncore PGA balance.

We do not have any evidence to suggest that PG&E improperly managed the noncore PGA nor to show that the balances were excessive at any time over the life of the service. Moreover, the lag between posting the price for service and receiving revenues from customers or paying suppliers made achieving a zero final balance very difficult. However, the fact that the balance is now a $5.2 million overcollection does not entitle PG&E shareholders to this money.

8.4 Transwestern Demand Charges

PG&E's requested forecast revenue requirement includes $18.5 million per year for Transwestern demand charges. PG&E proposes allocating these demand charges to all gas customers based on the cost allocation factors used for existing pipeline capacity.

Before and during hearings, no party moved for exclusion of Transwestern costs from the BCAP. A DRA motion was granted, however, clarifying that Transwestern costs are subject to a future ECAC reasonableness review. It was also made clear that any cost allocation used in this BCAP is subject to modification, and will be superseded by, the results of the capacity brokering proceedings (R.88-08-018, R.90-02-008).

DRA recommends the implementation of an interest-bearing memorandum account to track Transwestern pipeline demand charges, together with an explicit Commission statement that these costs are included in rates subject to refund. DRA argues that a memorandum account and Commission statement would serve two important purposes. First, it places PG&E, its shareholders and ratepayers on notice that the ultimate responsibility for these costs remains to be determined. Second, claims of retroactive ratemaking could not be advanced, claims which would seek to prevent the Commission from being able to allocate these costs to shareholders or ratepayers in any future decision with the allocation going back to the date the costs were first incurred.

PG&E asserts customary accounting treatment of the Transwestern demand charges provides complete protection for extracting Transwestern costs in the event of a reallocation or reasonableness determination. PG&E opposes the creation of a special interest-bearing memorandum account. In its reply brief, for the first time, El Paso Natural Gas Company argues for the exclusion of Transwestern costs from current rates based on D.92-07-025.

We now exclude Transwestern pipeline demand charges from the revenue requirement in this BCAP consistent with D.92-07-025 in R.88-08-018. As we there ordered, costs associated with PG&E's Transwestern capacity commitment will not be included in rates at this time. PG&E may enter the costs of Transwestern pipeline capacity in its balancing account subject to reasonableness review proceedings. Any Transwestern costs found reasonable will be allocated in a future BCAP. By this treatment, PG&E, its shareholders and ratepayers are on notice that all costs incurred by PG&E for Transwestern pipeline capacity are subject to future reasonableness and allocation decisions.

PG&E comments that there is no requirement that the Transwestern demand charge component of D.92-07-025 be implemented before implementation of D.92-07-025 generally. Further, PG&E argues Transwestern charges are not unique, requiring unique ratemaking treatment. To the contrary, our treatment of Transwestern costs in D.92-07-025 makes them unique. Further, to include them now for a brief period only to exclude them with full implementation of D.92-07-025 will add needless complexity to tracking these costs.

8.5 Core Direct Billed Take-or-Pay Account

Take-or-pay costs allocated to the core market are recovered through a one-way balancing account in accordance with the policy established in D.90-01-015 (35 CPUC 2d 3). This means that if PG&E recovers more than the authorized amount it must refund the overage, but if it recovers less, then the balance cannot be recovered. This treatment is designed so that PG&E shares in the risk of take-or-pay cost recovery.

PG&E's position on this issue is to true-up the account once every two years consistent with future BCAPs. TURN objects, arguing that a two-year true-up gives PG&E a greater opportunity to achieve full cost recovery. With annual true-ups, PG&E may overcollect in one year but that balance may not be used to offset a shortfall that occurs in the next year, according to TURN. Rather, TURN observes the balance would be refunded.

We decline to accept TURN's recommendation to continue the true-up annually. All other balancing accounts will be reviewed in accordance with the two-year schedule set for PG&E's BCAPs, and the core direct billed take-or-pay one-way balancing account should be treated consistently. Further, a two-year schedule for true-up allows the utility an opportunity to earn its authorized rate of return, while an annual true-up would not. The BCAP sets rates for two years and the forecast costs are spread over a two-year volume forecast. However, the forecast of core volumes is lower for the first year than the second. Therefore, the account can be expected to be undercollected in the first year and overcollected in the second year. An annual true-up of the account would therefore cause PG&E's shareholders to bear the first-year undercollection, while the second-year true-up would cause a refund of an overcollection to core customers. Without setting separate rates for each year of the BCAP, a two-year true-up period avoids the first-year undercollection/second-year overcollection situation.

8.6 Core PGA

The California Gas Marketers Group (CGMG) raises an issue after the filing of reply briefs. The matter involves the proposed amortization of PG&E's core PGA balancing account balance over the two-year BCAP period. CGMG is concerned that a mismatch is created for core customers who switch from utility sales service to transport only service (or who switch back) at or near the beginning of the BCAP period.

Transportation rates for core customers who qualify for transportation-only service are adjusted for the first year of transport service to include a component that reflects the balances in the core balancing accounts. (D.91-02-040, Appendix A, 39 CPUC 2d 360, 371.) Similarly, rates for core transport customers returning to utility procurement service do not include, for the first year, a component for the balances in the core balancing accounts. Under the former ACAP procedure, a one-year period for including or excluding core gas balancing accounts in core transportation rates was appropriate because these balances were fully amortized over the one-year ACAP period. Under the BCAP, the core PGA balance will be amortized over two years.

PG&E's core PGA is currently overcollected by $143 million. If, upon the effective date of this decision, a core customer switches from utility sales service to transport-only service, its core transportation rate over the next year will reflect a reduction due to the overcollection in the PGA account. Because of the two-year amortization period for the balancing account balance, however, the customer's rate reduction will only be for one-half of the customer's proportionate share of the balancing account balance, according to CGMG.

CGMG proposes three possible remedies. First, the core PGA could be amortized over a one-year rather than a two-year period. Second, a refund of the core PGA could be made to all core customers. This procedure was used in last year's ACAP to refund the overcollection in the core-elect PGA to all core-elect customers, according to CGMG. Third, D.91-02-040 (39 CPUC 2d 360) could be modified to provide a two-year period for including (or excluding) positive or negative balancing account balances in core transportation customers' rates. CGMG recommends remedy one, with the core PGA overcollection amortized over a one-year period.

PG&E recommends remedy three, with a two-year period for reflecting the core PGA overcollection in core transport rates. PG&E proposes "Experimental Core Gas Transport Service Schedule G-CT Rules" to implement this remedy. CGMG objects to PG&E's recommended rules, wherein PG&E proposes that customers taking service under Schedule G-CT before the effective date of this decision will continue to receive a credit for only one year following their initial switch to this service. CGMG also asserts that PG&E's proposal is overly simplistic, inadequate to ensure core transport customers get the full benefit, and will discourage core customers switching to transport-only service prior to the effective date of these BCAP rates.

Much as we said of the core-elect PGA issue in D.91-05-029, it is unusual for an issue such as this to arise so late in the proceeding and seemingly catch all parties by surprise. If this concern had been brought to our attention earlier, we would have solicited testimony on the appropriate mechanism to address these matters. However, no parties responded to CGMC's motion to supplement its reply brief concerning this issue, and the motion was granted. PG&E submitted a letter, to which only CGMC responded. We will decide the issue here given that no party moved for further hearing or other relief on this issue, the parties are apparently satisfied with what they submitted, and we desire to place PG&E's new rates in effect as soon as possible.

We decline to amortize the core PGA over one rather than two years in order to avoid two sets of BCAP rates, and because there will be approximately only 18 months in this BCAP cycle (since we direct PG&E below to file its next BCAP application on August 15, 1993). We also decline to order a refund. Core transport customers are only a small fraction of all core customers. A refund would disturb our policy of amortizing under- or overcollections (for rate stability) to meet the needs of very few customers while impacting many. We did refund the core-elect PGA overcollection in D.91-05-029, and do so for the noncore PGA overcollection (covered below), but the circumstances were and are different. The core-elect PGA involved a change in our regulation, while the noncore PGA is terminated. In contrast, we are not changing our regulation of the core PGA and it will continue.

We will adopt PG&E's recommendation with modifications as here described. We direct PG&E below to file its next BCAP application August 15, 1993 for effective rates April 1, 1994. We modify the Schedule G-CT rules to conform with the period of these BCAP rates (about 18 months).

CGMC is correct that the timing of this decision and these rules may be unfair to, or discourage some, customers (e.g., core customers who recently switched to core transport service). Customers make decisions to move from one to another service for many reasons. The overcollection was accumulated over many months. We are not able to design a rule that perfectly matches the return of the overcollection to those who paid while at the same time neither being unfair nor creating some skewed incentives for customers to switch service. But, customers could not have reasonably elected to switch or not switch based on this decision because they could not have known the decision in advance. Therefore, we direct the amortization only in relation to the service customers were taking August 1, 1992. We use August 1 rather than the effective date of this decision to avoid core transport customers switching to bundled service during review of the ALJ's proposed decision only so they could switch back after the effective date in hopes of receiving part of the amortization.

We use August 1 as a date which is sufficiently before release of the ALJ's proposed decision to prevent this gamesmanship.

We decline to modify D.91-02-040 since notice to all those bound by D.91-02-040 has not been given (e.g., SoCal, Southwest, and San Diego Gas & Electric Company). We will, however, adopt PG&E's proposed rules as amended above to implement this remedy for its core transport customers in this case. (See Appendix G.)

9. Discount Adjustment

Utilities may discount some noncore customers' transportation rates in order to make gas competitive with alternate fuels, and thereby prevent bypass. Costs and revenues for the BCAP test periods must account for discounting.

9.1 Noncore and Cool Water

While parties use different techniques to forecast discounting, there is agreement that forecast discounting should be zero in this proceeding, with the exception of discounting to the SCE Cool Water facility. Based on our adopted natural gas and alternate fuel price forecast, we adopt zero noncore discounting, with the exception of Cool Water.

PG&E originally forecast Cool Water throughput to be 9.9 MMdth per year for a total annual expected revenue of $4.7 million. DRA accepted PG&E's Cool Water estimates, but identified the potential for bypass. In its rebuttal testimony, PG&E forecasts that Cool Water will completely bypass PG&E's system and obtain service from SoCal. Stipulating parties agree on a forecast of 2 MMdth of throughput to Cool Water for each year of the BCAP test period, at a rate of $0.03 per therm.

SoCal's contract with SCE contains a large fixed demand charge and a small $0.03 per therm volumetric rate. For the reasons stated above, we adopt a conservative throughput forecast of 2 MMdth per year for Cool Water, at an incremental transportation rate of $0.03 per therm.

9.2 Methodology and Recalculation

PG&E proposes that the discount adjustment model be rerun whenever base revenues are revised. PG&E testifies that there is an inherent downward bias in the estimated discounting since base revenue increases from other proceedings are not incorporated when running the discount adjustment model. PG&E asserts that it would not be reasonable in a BCAP to attempt to forecast changes in the base revenue requirement resulting from other proceedings, in effect prejudging their outcomes.

We decline to adopt PG&E's proposal. Adopting PG&E's proposal would mean rerunning the discount adjustment and cost allocation models in every general rate case and attrition proceeding in which base rate revenues are revised. This would add needless complexity to already difficult or focused proceedings for adjustments which are likely to be small. Moreover, other factors (such as lower gas prices) may cause PG&E to overcollect industrial revenues relative to the BCAP forecast. PG&E does not request an offsetting adjustment, and we do not adopt one.

PG&E may negotiate risk protection in its discount service agreements with noncore customers. Utilities should have the opportunity and incentive to optimally manage risk for the benefit of their ratepayers and shareholders. Declining to rerun the discount adjustment gives PG&E the right incentive with the opportunity to manage risk in its discount contracts with noncore customers. Moreover, adoption of PG&E's proposal would provide another layer of risk protection for PG&E shareholders, contrary to our general gas restructuring policy to shift risk onto the company's shareholders as we create a competitive marketplace.

10. Cost Allocation

The purpose of cost allocation is to assign responsibility for a utility's fixed and variable costs to its customer classes. Parties raise issues regarding allocation of storage costs and various account balances.

10.1 Storage

PG&E proposes that storage costs be allocated based on the current Commission-adopted methodology (cold year peak season throughput), which allocates approximately 56% of storage costs to the core and 44% to the noncore. Neither DRA nor TURN took exception to PG&E's recommendation. Stipulating parties recommend continuation of the current approach.

CIG proposes that no more than 10% of storage costs be allocated to the noncore. Noncore transportation customers are afforded a 10% monthly load imbalance tolerance, according to CIG. Storage facilities provide this load balancing service and CIG recommends using this factor for allocating storage costs to noncore customers. CIG submits that it is incumbent upon the Commission at least to take this initial step to mitigate the current misallocation of storage costs, not putting off this issue until either the LRMC proceeding, the storage investigation (I.87-03-036), or the next BCAP.

CGMG proposes that noncore customers pay no storage costs, with all storage costs currently embedded in noncore transportation-only customers' rates being reallocated to core and core subscription customers on an equal cent-per-therm basis. Further, CGMG proposes that the subsidization of core subscription customers by core customers (who suffer reduced storage benefits due to core subscription service, according to CGMC) be corrected by reallocating storage costs to core subscription by the use of the equal cents-per-therm approach.

CGMG, like CIG, argues that PG&E's storage facilities are operated for the benefit of PG&E's core and core subscription, not noncore, customers. In addition, CGMG argues that the Commission's reasoning is backwards when the Commission views storage used to shave the peak demand of core customers in the winter months as conferring a benefit on noncore customers. CGMG testifies that the systemwide load balancing function of storage is incidental to the primary purposes of storage. CGMG argues that core subscription customer imbalance tolerance is unlimited, while noncore transportation-only customer imbalance tolerance is limited to 10%. The 10% imbalance tolerance has no relationship to the proper allocation of storage costs, contrary to CIG's testimony, according to CGMG. McFarland Energy, Inc. filed a brief in support of CGMG's recommendations.

We declined to change our cost allocation for SoCal's administrative and general expenses in D.91-12-075 because SoCal's study was insufficient and not persuasive, the amount of relief small, and the LRMC proceeding the proper forum. Largely for the same reasons, we decline to change our allocation of storage costs in this BCAP.

We are not convinced by the evidence and argument presented by CIG and CGMG. Storage provides benefits to noncore customers, including at least the provision of total gas system load balancing, the improvement of pipeline utilization, and the improvement of gas service reliability. CGMG's and CIG's witnesses acknowledged the load balancing and reliability benefits. We do not accept that these benefits are costless, as CGMG's proposal suggests. CGMG recognizes that storage helps to maximize utilization of interstate capacity, but fails to acknowledge that such greater utilization lowers average interstate transport rates to the benefit of all customer classes, including noncore.

CIG argues noncore transportation customers' storage benefits come in the pilot storage banking program, for which they pay a separate charge. We find, however, that any benefits obtained by participation in the pilot storage program are in addition to the three or more benefits of storage generally provided all customers, including noncore. The existence of the pilot program does not support a reallocation of storage costs here.

Further, we decline to accept that our previous reasoning is backwards. All customers who use the system during peak periods benefit from the increased system capacity that storage provides, not just customers whose loads vary by season.

Therefore, some storage costs are allocable to noncore. But we cannot adopt CIG's recommendation to allocate only 10% to the noncore. We are not convinced that the 10% load imbalance tolerance sufficiently captures the costs to justify sole use of this factor. We would make certain changes in this or other BCAPs based on sufficient evidence. We decline to make a fundamental change in storage cost allocation, however, based on the relatively summary evidence presented here.

We said in D.92-03-030:

> "We do not endorse Marketing Group's (CGMG) characterization of current cost allocation policies as unfairly favoring core subscription customers. Marketing Group has not presented information sufficient to reverse previous Commission findings on allocation of costs and benefits of gas storage.** If Marketing Group wishes to challenge present cost allocation policies, it must do so by presenting credible evidence; mere allegations in a petition do not suffice. In response to Marketing Group's petition for a forum to further consider storage issues, this [I.87-03-036, the storage investigation] is the relevant proceeding..." (D.92-03-030, pp. 3-4.)
>
> "**For example, Finding of Fact 12 in D.87-10-043, 'The utilities' storage fields increase the reliability of service for all gas users in California, including transportation-only customers.'"

CGMG argues that it presented sufficient information in this BCAP to reverse previous Commission findings. We disagree. Equally so, CIG's 10% is not based on an adequate study. A credible, comprehensive study fully and properly accounting for costs and benefits is necessary before we will consider changing our method of storage cost allocation. CGMG, CIG, and others interested in storage cost allocation should focus their efforts in the storage investigation (I.87-03-036) and there present sufficient, credible evidence.

10.2 Allocation of Undercollection in Brokerage Fee Balancing Account

PG&E proposes that the $7.3 million undercollection in the brokerage fee balancing account be recovered from both core and noncore ratepayers. Both DRA and TURN recommend that only noncore customers bear the undercollection in the account. CGMG proposes that the undercollection be recovered exclusively from core subscription customers. The stipulating parties recommend that the undercollection be recovered from all noncore customers. In its brief, CIG argues the PG&E position that it should be allocated to all ratepayers.

We direct the recovery not just from core subscription customers but from all noncore customers, including core subscription. The undercollection results from a variation between the forecast core-elect and noncore portfolio sales volumes in PG&E's 1991 ACAP, and the actual volumes purchased by core subscription customers, primarily occurring after August 1, 1991 when our procurement rules were implemented (D.90-09-089, 37 CPUC 2d 583). The reduction in volumes of procurement services to noncore customers which led to this variation was caused by customers who are currently noncore transportation only customers who had previously purchased gas from PG&E. CGMG's proposal misses this critical point, even though CGMG's witness agreed that any noncore transportation only customers who had been subscribing to PG&E's core-elect or noncore procurement services prior to August 1, 1991, would have contributed to the current undercollection in the account.

CIG recommends modification of the stipulation because of the stipulation's recommended recovery of this undercollection from only noncore customers. CIG asserts that core as well as noncore fixed costs accounts were reduced by forecast brokerage fee revenues in D.91-05-029. CIG contends that core customers directly benefited from the forecast brokerage fees, and should therefore bear some of the costs of the undercollection.

We disagree. Our allocation of $6.4 million of brokerage fee revenues to the core in D.91-05-029 is not in conflict with our decision to allocate the $7.3 million current undercollection to the noncore. Brokerage fees are incurred for both core and noncore customers. Reallocation of brokerage fees occurred concurrent with our unbundling of gas services and costs. We said of brokerage fees in D.89-09-094:

> "For the time being, PG&E should establish an account to track brokerage fee revenues which would be used to offset the revenue requirement [i.e., costs] for core and noncore customers in the next PG&E ACAP."
>
> * * *
>
> "We will implement the brokerage fee in PG&E's 1990 test year ACAP decision. Transportation and core rates established in that decision will reflect the adjustments adopted in this decision."
>
> * * *
>
> "In PG&E's test year 1991 ACAP, actual costs, based on a new cost study, will be used." (32 CPUC 2d 500, 507.)

We applied this approach in PG&E's 1990 ACAP (D.90-04-021), and, because the new cost study was not available, in PG&E's 1991 ACAP (D.91-05-029). We made adjustments later, in D.91-11-055, when the study was available.

Thus, our allocation of brokerage fee revenues to core customers was consistent with brokerage fee costs and our unbundling of those costs. But, we also said:

> "As we have stated, the implementation of the brokerage fee should make PG&E, not core ratepayers, liable for brokerage fee revenues and should promote a competitive market. At the same time, we must provide PG&E with an opportunity to recover its adopted revenue requirement." (32 CPUC 2d 500, 507.)

Recovery of the current undercollection from noncore customers is consistent with our prior direction to make PG&E, not core ratepayers, liable for brokerage fee revenues, while at the same time providing PG&E with an opportunity to recover its adopted revenue requirement.

Moreover, core customers pay their own brokerage costs through the bundled core rate, and are therefore properly excluded from being charged this undercollection. The undercollection is a result of core subscription customers transferring to noncore service, not core customers being allocated certain revenues. It is thus appropriate to charge this undercollection to noncore, including core subscription, customers. Since all noncore customers now have gas procurement choices, the balance should be allocated to the noncore class, and not solely to those customers who remain in core subscription service. Moreover, the brokerage fee revenue requirement includes embedded costs (e.g., indirect and overhead costs) and is therefore not simply based on the incremental cost of selling gas to noncore customers. Rather, it includes components for which all noncore customers are responsible.

10.3 Refund of Overcollection in Noncore PGA

PG&E recommends that the $5.2 million overcollection in the noncore PGA be given to shareholders. DRA proposes that the overcollection be credited to the noncore fixed cost account. The stipulating parties propose that in the event the Commission decides to reject PG&E's proposal and instead adopt DRA's proposal, that the balance be given to all noncore customers by crediting the noncore fixed cost account. Luz presents for the first time in its opening brief a recommendation that the overcollection in the noncore PGA be refunded to those customers buying gas through the noncore PGA in the months of May to July 1991.

As discussed above, we are persuaded that the overcollection should be returned to ratepayers, not shareholders. Moreover, we are convinced by Luz that it should be returned to those noncore customers who purchased gas accounted for in the noncore PGA in the months of May to July 1991.

Noncore portfolio customers are only part of PG&E's entire noncore class. The stipulation would allocate the noncore PGA overcollection to all noncore customers. The stipulation would thus allocate some of the noncore PGA balance to noncore customers who did not purchase noncore portfolio gas during the period when the final overcollection was accumulated. This would provide a windfall to those customers, and deprive those who actually bought gas at somewhat inflated prices of a refund.

PG&E argues that Luz's proposal should be rejected. PG&E points out that Luz presents its argument for the first time in its opening brief, a last-minute proposal depriving others of the opportunity to cross-examine or point out flaws through rebuttal testimony. We cannot reject Luz's recommendation on this basis. The Commission encourages parties to participate early and fully in all proceedings. We cannot force a party to do so, however. Parties have a right to participate only through submitting a brief if they wish. Even though this proposal comes late in the proceeding, parties were able to, and did, address Luz's proposal in their reply briefs. Moreover, any party could have moved for a reopening of the record, if they believed the record to be inadequate. No party did so.

PG&E suggests that Luz's proposal is made because Luz purchased a substantial amount of gas from the noncore portfolio during this time, a fact PG&E asserts would have been uncovered if it had the opportunity to test Luz's proposal during cross-examination. Equally so, the amount of gas bought by PG&E's UEG during this period could presumably have been determined. Nonetheless, while Luz may have been a substantial purchaser, this does not invalidate the argument that those who contributed to the overcollection are, in fairness, due the refund, including PG&E's UEG.

PG&E argues that Luz's proposal conflicts with Commission policy against retroactive rate adjustments to noncore portfolio service, citing D.87-12-039 (mimeo. p. 107; 26 CPUC 2d 213, 281). There is no conflict. We said:

> 'With frequent posting and fairly good forecasting the adjustments should never be large. The critical issue from the customers' and competitors' points of view is that the adjustments should not be applied retroactively for past usage.' (26 CPUC 2d 213, 281.)

During the account's life both under- and overcollections were corrected in subsequent months, not applied retroactively with refunds or surcharges to customers based on past usage. The account, however, has now terminated. Any concern about applying adjustments retroactively as an ongoing principle guiding account operation no longer applies. Rather, fairness dictates that those customers who actually paid the overcollection are due the refund.

PG&E argues that Luz's proposal of refunds to customers making purchases in the months of May through July 1991 presents an arbitrary timeframe. April could have been selected, argues PG&E, being the month when the balance crossed from negative to positive. PG&E says the month the account was established could equally have been selected. We disagree. We directed account operation with frequent posting and fairly good forecasting so the adjustments would never be large. Those customers over- and underpaying in any month paid a rate in the next month that included a factor seeking to neutralize the balance.

Indeed, PG&E achieved success in that goal, with the month-ending balances fluctuating between positive and negative six times during its operation. PG&E offset an undercollection accumulated through July 1990 by adjusting the WACOG and collecting revenues greater than expenses in all but one month from August 1990 through July 1991. The undercollection of $1.3 million in April 1991 became an overcollection of $0.6 million by the end of May 1991. At some point in May 1991, the account balance was zero. We do not have data on the daily account balances and we do not seek that information. Customers in May through July 1991 clearly paid the $5.2 million overcollection. It is those customers who should get a refund.

In support of the stipulation, DRA contends that administrative convenience dictates a generalized return of the $5.2 million to noncore ratepayers as a whole. PG&E concurs, claiming it would be difficult to attempt to determine any alternative refund scheme. To the contrary, while the circumstances which led to our refunding the $46.7 million overcollection in the core-elect PGA in D.91-05-029 were different than those facing us with the noncore PGA (e.g., memo versus balancing accounts; different market considerations; different size of the refund), we there ordered a refund to specific customers, and we order a similar refund here. This refund is based on the unique circumstances with this account and does not establish a precedent that future under- or overcollections be eliminated by refunding or back-billing customers based on prior usage, just as we found true for the core-elect PGA refund. The only concession we make to administrative convenience is to abandon a search for daily account balances of the noncore PGA. We order this refund with interest. The noncore PGA did not accumulate interest during its operation, since overcollections could balance undercollections and neutralize the need for interest. Upon account termination, however, the final balance was fixed (except for late-booked entries and adjustments).

PG&E has a fiduciary duty to responsibly manage money in its possession. PG&E would have been obligated to finance a deficit at the least reasonable cost if the balance was negative. Similarly, an overcollection must have been put to reasonable interest-bearing use.

There was no intention with account termination that PG&E finance a deficit at its own cost, get an interest-free loan or keep the return from investing the balance until this decision. Therefore, we direct the refund with interest at the rate earned on three-month commercial paper, as reported in the Federal Reserve Statistical Release, G.13, or its successor, from August 1, 1991 until the payment is made.

We direct PG&E to credit customer's bills, as PG&E requests, rather than issue refund checks. The refund should be calculated on an equal cents-per-therm basis and returned to customers who purchased noncore portfolio gas in May through July 1991. PG&E should administer the refund within 120 days of the effective date of its tariff schedules filed in compliance with this decision.

Solar Partners comment that the refund should be calculated per month rather than as an average over the three months. We disagree. A per-month calculation will do little to increase accuracy and will make difficult the allocation of the balance accumulating after the account terminated at the end of July 1991.

10.4 Other

PG&E recommends that the remaining balance in the natural gas vehicle pilot program account be allocated to all customers on an equal cents-per-therm basis, that the balance in the noncore fixed cost account be allocated to all noncore customers on an equal cents-per-therm basis, that the customer energy efficiency account balance be allocated according to weighted number of customers across all classes (consistent with the method used to allocate customer energy efficiency program costs) and that any balance in the firm surcharge/interruptible credit account be included in the determination of the interruptible credit. No party took issue with these recommendations. Stipulating parties recommend that PG&E's original proposals be adopted. We adopt PG&E's proposals. PG&E comments that the stipulation uses an incorrect entry for the customer energy efficiency account. We make that correction.

11. Rate Design

11.1 Alternate Fuel Requirement for Noncore Status

Several interrelated issues fall in this category. After considering all the evidence and arguments, we decide to: eliminate the alternate fuel requirement and the requirement that customers electing noncore status pass an economic practicality test to achieve that status; increase the penalty for failure to comply with a curtailment order to $16 per therm; reiterate that customers who fail to curtail must be moved to the appropriate core rate schedule; retain existing rules for penalty application (rejecting an advance notice requirement or a 24-hour grace period); set the minimum size requirement for noncore status at either 100 Mcf per peak day or 20,800 therms per active month; and allow existing noncore customers to retain their noncore status even if they are below the size requirement. Implementation of these changes is suspended, however, pending further consideration in the limited scope proceeding in R.86-06-006 ordered in D.92-03-091.

11.1.1 Eliminate Alternate Fuel Requirement

In D.92-03-091 we stated our intentions to eliminate the alternate fuel requirement for noncore customers, to increase the penalty imposed on noncore customers who fail to curtail gas use when directed to do so, and to allow customers who have been designated noncore to retain that status pending further review in R.86-06-006. While these items were litigated in this case, DRA argues that D.92-03-091 reserves these and related issues to R.86-06-006. That, however, was not our intent. We observed in D.92-03-091 that elimination of the alternate fuel requirement is directly linked to the size of the penalty, and that PG&E had already proposed changing the amount of the penalty in its pending (this) BCAP. We intended to make as full use as possible of the record in this BCAP. We agree with PG&E that a reasonably complete record has been compiled on these issues in this proceeding. To the extent D.92-03-091 refers matters to R.86-06-006, we mean that the decisions made here, including the further matters raised herein, are subject to review in combination with proposals made by SoCal and SDG&E in R.86-06-006.

We eliminate the alternate fuel requirement for many reasons. Our current alternate fuel requirement can be waived under some circumstances (e.g., economic feasibility test). As a result, some customers have to install and maintain an alternate fuel system, and others do not. Elimination of the alternate fuel requirement will promote similar treatment, reduce administrative costs, and promote fairness. Further, it will allow the customer to determine the best way to respond to a curtailment (i.e., rely on an alternate fuel, discontinue operations, perform equipment maintenance, do some other action or some combination of actions). It will contribute to environmental benefits by allowing the removal, in some cases, of underground fuel tanks which can cause air and groundwater contamination or needless exposure. Finally, as CIG's witness testifies here, it will allow the replacement of older boilers with a more efficient system, saving enough natural gas to heat many homes, a conversion not possible with the existing alternate fuel requirement, CIG states, because the plant would lose its grandfathered air quality permits upon removal of the existing boilers.

DRA and TURN oppose the elimination of the alternate fuel requirement since it blurs the distinction between core and noncore customers, causing unknown and unforecasted rate impacts on the core class. No party in this proceeding has made a forecast of load migration from core to noncore classes if the alternate fuel requirement is eliminated. CIG argues that a load forecast is not necessary, however, since rate impacts can be followed with a tracking mechanism established in this proceeding and treated in the next BCAP. TURN agrees with CIG, but also observes that PG&E's demand forecasts do not reflect that a significant number of core customers have already transferred to noncore status. An undercollection in the core fixed cost account will result, according to TURN. The actual transportation revenues these customers pay will be recorded in the noncore fixed cost account, TURN asserts, generating an overcollection of noncore revenues, 25% of which are retained by PG&E's shareholders.

As we did for SoCal in D.91-12-075 (Ordering Paragraph 13, mimeo. p. 96), we order a tracking account for customers transferring to noncore status after August 1, 1991 (the deadline specified in Resolution G-2948). The tracking account will be recorded in the core fixed cost account. It will accrue the difference between the amount these transferring customers have actually paid or will pay and what they would have paid if billed at core rates. Parties may address the allocation of this account in PG&E's next BCAP. This mechanism is required given our elimination of the alternate fuel requirement without a concurrent forecast of additional core to noncore transfers, and because some customers have already been allowed to change their status. This approach satisfactorily addresses DRA's and TURN's rate impact concerns.

In conjunction with our decision to eliminate the alternate fuel requirement, we also eliminate the necessity for core customers to apply for and pass the economic practicality test, as established in D.87-12-038 and clarified in D.88-03-085. Customers meeting the size requirements outlined below may elect noncore status without justifying the economic practicality of their choice.

11.1.2 Penalty

PG&E proposes to increase the penalty for failure to comply with a curtailment request from $1 per therm to $25 per therm. PG&E argues that a customer could decline to curtail for a substantial number of days, pay the $1 per therm penalty, and still be economically better off paying noncore compared to core rates. Some noncore customers or their represenatatives (e.g., Aebi Nursery, the California Floral Council, and the California Cut Flower Commission (jointly referred to herein as Aebi)) do not object to a penalty of $25 per therm. Others (e.g., CIG and California Cogeneration Council (CCC)) oppose an increase in the penalty. If the penalty is adjusted, CIG argues it should be raised to no more than $2 per therm for existing noncore customers, and $17 per therm for new noncore customers (the $17 calculated using PG&E's assumptions but updated for PG&E's revised rate proposal). TURN supports a $17 per therm penalty.

We raise the penalty from $1.00 to $16.00 per therm. Whatever the level of the penalty, as we said in D.92-03-091, "customers are capable of determining whether they require an alternate fuel system or would be better off facing curtailment in other ways." (Mimeo. p. 6.) But we stated "we believe the trade-off for eliminating the alternate fuel requirement must be a higher curtailment penalty." (Mimeo. p. 7.) If a higher penalty forces customers who elect to respond by using alternate fuels to purchase alternate fuel systems, we said "[t]hat is as it should be." (Mimeo. p. 7.) This is equally true if a higher penalty forces customers who elect to use alternate fuels to perform increased maintenance and keep their alternate fuel systems ready for immediate use. PG&E's proposal of $25 per therm makes a customer worse off after three days (72 hours) of failing to curtail, calculated at PG&E's initially proposed rates. Corrected for the rates we adopt, the equivalent penalty is $16 per therm.

CIG argues that PG&E fails to show the existing penalty is ineffective or causes a "free rider" problem (a free rider being a customer who would take advantage of the lower noncore rate but would have no intention of curtailing use). CIG refers to D.91-09-085, where we declined to increase the penalty and said: "We will be open to future arguments that the penalty should be modified if experience shows that it is not sufficient to ensure that curtailment is occurring." (Mimeo. p. 2.) This is one way we would be open to reexamining the penalty, but we did not state this would be the only way. Given very limited curtailment experience with the penalty in place, the data may be insufficient to conclusively determine the effect of the penalty. We now have evidence, however, that the $1 per therm penalty leaves noncore customers better off by failing to curtail for up to 50 days at PG&E's initially proposed rates (up to 49 days at our adopted rates) and simply paying the penalty compared to paying core rates. PG&E's proposal to lower the threshold to 72 hours is reasonable.

In fact, reducing the threshold to somewhere substantially below 72 hours may be appropriate. Noncore customers understand that their rejection of core service in exchange for reduced rates carries with it a greater risk of curtailment than the risk faced by core customers. It may be unreasonable to set the penalty so low that a noncore customer may decline to curtail, thereby essentially receiving core quality service, for even a few hours and be economically better off compared to paying core rates. We will carefully consider recommendations parties may make on this in R.86-06-006.

CIG testifies that the $1 per therm penalty provides a substantial and meaningful measure of deterrence, and, in the case of one customer, translates into approximately $20,000 per day. CIG's witness asserts that a penalty of this magnitude affects profitability and a higher penalty would threaten the very existence of the firm itself. The witness further testifies that a large penalty would force customers to make unnecessary capital investments in alternate fuel systems, facilities which are likely to be unused and simply "gather dust." The witness fails, however, to place the $20,000 per day in perspective. No information was provided on the size (total company, not amount of gas consumed), process, or financial condition of the customer.[3] A penalty of $20,000 for a customer failing to curtail for 24 hours may be a very small price for a very large customer (large in the customer's own industry and overall financial situation, not large in the amount of gas consumed), or a customer who places great value on the gas. As we said in D.92-03-091, if the penalty forces customers to make capital investments, that is as it should be. Customers are free to make their own decisions whether to install facilities they believe will remain unused and gather dust, or comply with a curtailment request in some other manner.

CIG testifies that it is improper to calculate the penalty based on the relationship between noncore and core rates. To the contrary, noncore customers should become core customers if they require greater reliability. If noncore customers fail to curtail when requested, they effectively enjoy core service. The appropriate test is therefore to the core rate, not their current

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3 The Department of General Services comments that it is unaware the Commission determines rates based on a customer's process or financial condition. We note that our comments here are in the context of the weight to give CIG's testimony. It is CIG that raises the matter of the impact of the penalty on the customer.

noncore rate. Curtailments may become necessary at any time due to any number of factors (e.g., weather, pipeline failure, supply limitations, international politics). If a curtailment order is given, however, those customers on schedules providing for their curtailment must curtail so that core customers, including businesses who elect to pay core rates for core reliability, receive the reliability and the gas for which they are paying.

CIG argues it is impractical to use core rates as an economic alternative when it appears that only one small commercial noncore customer has ever converted to core status. Rather, CIG asserts that noncore customers have many less expensive alternatives, such as the use of alternative fuels and production curtailment. The use of less expensive alternatives is exactly the point. We set the penalty in relation to the effective quality of service if the noncore customer declines to curtail (i.e., core quality service) with the expectation that noncore customers will use their less expensive alternatives rather than violating a term of their rate schedule.

CIG argues that "the overall objective of a penalty for failure to curtail should be to provide a significant economic deterrent to prevent any customer from engaging in such practices on a frequent basis." (Initial brief, April 16, 1992, pp. 21-22.) We cannot agree if CIG believes that failure to curtail when requested is acceptable as long as it is not too frequent.

CIG pleads that circumstances may not allow a customer to immediately curtail gas use despite a customer's diligent and good faith efforts, and even despite the existence of installed alternate fuel capability. Because of this, CIG states the penalty should not be at a level that would devastate business. We enthusiastically agree. The penalty we adopt here would allow a noncore customer to fail to curtail for up to 72 hours and still be better off compared to paying core rates, even though the noncore customer would be enjoying essentially core quality service. This sufficiently accounts for customers not being able to immediately curtail while not setting the penalty at a level to devastate business, especially in relationship to the rates paid by competitors who choose core service. As we said above, however, 72 hours may be quite generous and we will closely examine this in R.86-06-006.

CIG asserts the prudent course of action would be to monitor the situation during curtailments, analyze the reasons for any failure to curtail, and then adjust the penalty to deter customers if abuses have occurred. We disagree. It would be irresponsible regulation to retain a low penalty rate in the face of this evidence. We will monitor the experience with future curtailments and make adjustments as necessary. But, we will not at the same time place core customers at risk for a degradation in their service by retaining a low penalty rate which allows noncore customers to decline to comply with curtailment requests for up to 49 days and be no worse off.

Core customers are left with more "stranded" costs (at least in the short run) as other core customers migrate to noncore service. The noncore service trade-off is a greater risk of curtailment for a lower rate. For this lower rate, however, noncore customers must fulfill their commitment to curtail when requested. If they do not, they have not only negatively impacted core rates by their migration, but they both enjoy the equivalent of core service without paying its costs and jeopardize core service to all other customers. It is important that customers electing noncore service understand they are subject to a lower quality of service. As such, they must face a penalty that is meaningful, and sends a clear and unambiguous signal. A penalty of $16 per therm will accomplish those goals pending further review in R.86-06-006.

11.1.3 Conversion to Core Schedule

Noncore rate schedules specify that noncore customers will curtail when requested by the utility. PG&E proposes that any customer who fails to curtail be placed on the appropriate core rate schedule. CIG argues that this is an even worse penalty than the penalty charge for failing to curtail, that it is unaffordable, and that it must be rejected.

We endorse PG&E's request. Allowing a customer to remain on a noncore rate schedule in violation of the conditions of service would grant a preference or advantage to that customer relative to other customers, in violation of Public Utilities (PU) Code § 453(a). But we will also retain the $16 per therm penalty charge since the risk of being assigned to a core rate schedule is itself not a sufficient deterrent. Without a penalty charge in addition to being reassigned, the customer would receive the benefit of the noncore rate until such time as they fail to curtail. At that time they would be placed on the core rate schedule from which they should have been served all along. The customer would then be in the same position as if they had selected the core rate in the first place but they would have enjoyed the lower noncore rate for some time. Therefore, the noncore customer must face both a penalty charge and a reassignment if they fail to curtail.

Customer reassignment, however, should only be when there is a pattern, or reasonable expectation, of abuse. The penalty for a customer failing to curtail is sufficient when reasonable attempts are being made by the customer to comply. A pattern, or reasonable expectation, of abuse, however, would be unfair to core customers and therefore cannot be tolerated.

11.1.4 Grace Period

CIG recommends that, regardless of the level of the penalty for failure to curtail, a 24-hour grace period be allowed before customers are subject to the penalty provisions. CIG's witness testifies that PG&E is not always able to provide substantial advance warning of a curtailment and a customer may not be able to immediately switch to alternate fuels when given little or no notice. Twenty-four hours may be needed by customers to get their alternate fuel systems fully operational and to safely curtail production at their facilities, according to CIG.

We reject CIG's recommendation. PG&E simply would not be able to operate its system if all noncore customers waited a day (24 hours) before beginning to comply with a curtailment request. Even if PG&E could operate its system with this lack of response, the failure to curtail would be an intolerable burden on the ensuing reliability of core service.

Establishing a specific number of hours during which a noncore customer can decline to curtail would allow noncore customers to decline to curtail even when they could otherwise cease their takes. The need for a curtailment can arise suddenly. We do not think it reasonable to require anything more of PG&E then that it give as much notice of an impending curtailment as is reasonably possible. In fairness to core customers, we then expect noncore customers to comply.

Therefore, we will neither add a specific advance warning requirement nor grace period before the penalty for failure to curtail applies. Rather, we will retain PG&E's existing tariff provisions including Rule 14, wherein PG&E must give as much notice of an impending curtailment as is reasonably possible (e.g., PG&E's tariff Rule 14.H.1) and the penalty applies without a grace period (e.g., PG&E tariff Rule 14.H.8).

CIG's witness testified that in the January 1992 curtailment episode he was not notified that balancing gas had been curtailed until three hours after the curtailment began. To the extent CIG is arguing that no penalty for noncurtailment should attach until after a customer has been notified of the curtailment, we agree and so direct PG&E. If PG&E incorrectly applies the curtailment penalty, the customer should first seek a correction from PG&E. If that fails, the customer may seek informal or formal Commission intervention to assure proper application of PG&E's tariffs.

To ensure proper notice, a noncore customer may wish to provide PG&E a specific contact for notification of an impending curtailment, if neither the customer nor PG&E has yet done so. Parties may propose this or similar changes to PG&E's tariff Rule 14 in R.86-06-006, if such changes are necessary.

We are not unsympathetic to the argument of CIG for a grace period. At the same time, we note other noncore customers or their representatives (e.g., Aebi) do not object to a $25 per therm penalty, stating they have no intention of ignoring curtailment orders. They state they understand that interruptible service means service may be interrupted. Further, they say they "are able and willing to drop off the system when necessary and free up gas supply for those who cannot curtail." (Aebi Opening Brief, April 8, 1992, p. 7.) An alternative that may be satisfactory (if it is not too administratively burdensome and as long as it does not encourage noncore customers to delay curtailing) is an increasing curtailment penalty. That design would apply a lower penalty per therm during the first hour after a curtailment notice, with the amount of the penalty increasing as the number of hours grows. An increasing penalty may also address our concern that a flat $16 is based on a perhaps too generous number of hours before the penalty is meaningful in relation to core rates. Parties may wish to comment on this alternative in R.86-06-006.

<u>11.1.5 Size Requirement</u>

There is general agreement with a Foster Poultry Farms' proposal that, if the alternate fuel requirement is eliminated, any customer having either a minimum of 100 Mcf per peak day usage or 20,800 therms per active month usage be eligible for noncore status. Aebi objects to the extent existing noncore customers below these limits would be restricted from noncore service.

With our elimination of the alternate fuel requirement, we adopt the standard that any customer consuming 100 Mcf or more per peak day or 20,800 therms or more per active month is eligible for noncore status. We address Aebi's concern below.

11.1.6 Existing Noncore Customers

Aebi opposes the elimination of the alternate fuel requirement as discriminatory against small growers. They also assert that the size requirement will be punitive to small growers.

As we determined in D.92-03-091, we will allow customers who have been designated noncore in reliance upon either Resolution G-2948 or G-2959 to retain their noncore status pending further review in R.86-06-006. This will accommodate existing small nurseries and growers. But, we are equally concerned with new customers who are below the size requirement. We therefore will closely examine parties' proposals in R.86-06-006 for realistic and practical definitions of core and noncore classes which do not discriminate against small or new competitors, and which promote equity between existing competitors. In addition, we ask parties, in making their proposals in R.86-06-006, to consider the interrelatedness of all the terms addressed in this section.

11.1.7 Suspend Implementation

On October 19, 1992, PG&E served a letter on all parties. PG&E states it is now reconsidering its recommendations on these matters (even though its earlier comments supported the discussion of these issues in the proposed decision), as a result of meetings with representatives of noncore customer groups. PG&E states that the penalty must be sufficient to prevent intentional noncompliance, but must not be so onerous that it discourages businesses from using gas in California. PG&E recommends that the decision on noncore alternate fuel requirements and curtailment penalties be deferred to R.86-06-006, pursuant to D.92-03-091.

DRA originally argued that D.92-03-091 reserves all these and related issues to R.86-06-006. For all the reasons stated above, we find these changes are reasonable and appropriate. We adopt these changes here. Simultaneously, however, we suspend these changes pending further review and consideration in R.86-06-006.

11.2 Residential Rates

PU Code § 739.7 requires that the Commission reduce high nonbaseline residential rates as rapidly as possible. PG&E observes that parties have proposed several methods to reduce the differential between Tier I and Tier II residential rates in past ACAPs. Rather than examining this issue repeatedly in every rate case, PG&E proposes the adoption of a multiyear residential rate design policy that will reduce (and may eventually eliminate) the differential.

DRA supports a multiyear tier closure policy. DRA generally agrees with PG&E's proposal, endorsing a substantial tier closure now but with some safeguards against large swings in future rates.

TURN testifies that PG&E and DRA go too far by proposing a multiyear plan that could virtually eliminate any significant tier differential. TURN objects to automatic future tier differential reductions, and observes the Commission has always handled tier differential reduction on a case-by-case basis (in order to retain flexibility), with no compelling reason to depart from that approach here. TURN recommends that the Tier II rate not be less than 135% of the Tier I rate. TURN observes that a 35% tier differential is in the range of Commission-adopted differentials prior to the mid-1980's, when Tier II rates began to dramatically increase.

The stipulating parties recommend a rate design policy only for this BCAP period. They recommend that PG&E's proposal be used with three limitations, designed to safeguard against large swings while closing the differential and maintaining at least a 35% spread.

We adopt a residential rate design policy which we will use until PG&E's next BCAP. We do this because BCAPs are the proceedings in which we consider gas rate design, at least until such time as we move consideration to the general rate case. (D.89-01-040, 30 CPUC 2d 576, 608.) Gas rate design is not an issue in PG&E's pending general rate case (A.91-11-036), except for the MARL discussed below. We do not consider gas rate design in ECAC, attrition rate adjustment (ARA), or other miscellaneous proceedings. It is therefore reasonable to adopt a gas rate design policy in this BCAP which we will implement in the general rate case, ECACs, ARAs, and other proceedings until the next BCAP.

We adopt a policy based on PG&E's proposal with the modifications recommended by DRA and TURN. We specifically adopt the terms that:

a. If the average residential gas rates are decreasing, all of the decrease will be allocated to Tier II;

b. The Tier II gas rate will not drop below 135% of the Tier I rate; and

c. The Tier II/Tier I ratio of 135% will not be changed on a percentage basis once that limit is reached.

Because we reach the 135% limit in this decision, the other specific terms of the policy are moot (e.g., various terms during increasing rates; revenue neutral changes each May to bring the ratio down to 135%). The 135% ratio is controlling and we will maintain that ratio as we change residential rates in other proceedings, until the policy is reassessed on the next BCAP.

Rates, whether declining or inverted block, send important information to customers. We agree with TURN that an appropriate price signal in the rate structure may eliminate the need for expensive utility-funded incentive programs. Conservation and energy efficiency are critical in these difficult times, and we agree the Tier II/Tier I differential should not be reduced below a ratio of 135% before a further examination in the next BCAP. Gas marginal costs will soon be known from R.86-06-006, et al. We will consider whatever changes are appropriate to this residential rate design policy in the next BCAP when we have the benefit of our decision on marginal costs.

11.3 UEG-Cogeneration Rate Parity

PG&E proposes to exclude the CPUC fee paid by cogenerators in the UEG-cogeneration rate parity calculation. CCC opposes PG&E's proposal, and further recommends that UEG ignitor fuel be excluded from the UEG-cogeneration rate parity calculation. We will include the CPUC fee and exclude UEG ignitor fuel in the parity calculation.

We are not convinced by PG&E that the CPUC fee was incorrectly included in the rate equalization calculation in past BCAPs. Equally, we are not convinced by PG&E's claim that the CPUC fee paid by cogenerators is analogous to a utility tax and should be excluded in the calculation just as are local utility taxes paid by cogenerators.

UEG ignitor fuel is a core service and is not properly included in either UEG noncore rates or noncore cogeneration rates. We agreed with CCC on that point in D.92-07-025 (mimeo. p. 25). PG&E's argument that the parity statute (PU Code § 454.4) and prior Commission decisions do not exclusively mention parity by service level fails. D.92-07-025 clarifies that we intend the parity calculation to be done on a service-level basis (Ordering Paragraph 13, mimeo. p. 55).

11.4 Noncore Peaking Rate

TURN recommends the adoption of a noncore peaking rate for those customers who take advantage of bypass opportunities but continue to rely on PG&E to meet their peak demands. TURN argues this rate would begin to confront the bypass issue from a rate design perspective. As a counter to potential bypass, this proposal is superior from the core customer perspective to a reallocation of costs from noncore to core, according to TURN.

PG&E takes no position on TURN's recommendation but points out most of the bypass forecast on the PG&E system is total bypass, leaving no peak load. Moreover, PG&E wishes to retain its existing ability to negotiate rates, including the peaking rate, in order to maximize revenues. Further, PG&E observes that the negotiable peaking rate has the potential to be an area of substantial additional dispute in future cost allocation proceedings given the amount of controversy discounting has engendered in past proceedings.

DRA and SoCal support TURN's recommendation. CIG offers that the record is inadequate to adopt this proposal.

TURN's proposal has merit. Bypass is a growing reality, as the discussions of bypass by Dow, Southwest, and PG&E's own UEG department illustrate. We seek to send the appropriate economic signals to customers regarding the cost of bypass by the design and level of rates. Customers are now planning and computing the economics of bypass.

The proposal, however, does not adequately address how the peaking rate can be made consistent with our existing rates: volumetric rate for the UEG class; firm, interruptible, summer and winter rates for the cogeneration class; and summer and winter rates for the industrial class. It does not adequately explain how the rate can be designed to promote efficiency without reference to marginal costs, nor does it explain how implementation will impact existing rates. Moreover, there may be some confusion whether its implementation will generate more revenue or result in a revenue shortfall (as some customers respond to the new rate), and how this revenue impact is properly measured and treated. Therefore, we are unable to adopt a noncore peaking rate here.

11.5 UEG and Wholesale Service Level Election

We adopt PG&E's recommendation, which no party opposed and DRA endorsed, regarding future changes in service level nominations for UEG and wholesale customers. PG&E shall file an advice letter, at the time new service level nominations are made, to change the fixed demand charge component of the UEG and wholesale rates to reflect any changes in service level nominations. Revenues and credits due to the new service level nominations will be tracked in the firm surcharge/interruptible credit account.

11.6 Master-Meter Discounts and Minimum Average Rate Limiter (MARL)

As provided in PU Code § 739.5, master-meter customers who submeter receive a monthly discount per submetered tenant (Schedules GT and GTL for mobilehome parks; Schedules GS and GSL for multifamily residences). The discount is reimbursement for utility service provided by the master-metered customer.

11.6.1 Recalculation of the Diversity Adjustment for Master-Meter Rate Schedules

We adopt WMA's unopposed recommendation to recalculate the diversity adjustment to the discount based on our adopted residential rates and using PG&E's 1993 general rate case diversity adjustment model. The diversity adjustment accounts for the master-meter customers' ability to buy a portion of their master-meter therms at Tier I rates and resell them to submetered residents at Tier II rates. This recalculation increases the master-meter discount by reducing the diversity adjustment, to reflect the lower diversity benefits resulting from the adopted residential rate tier closure. We make this recalculation for Schedules GT, GTL, GS, and GSL.

11.6.2 Proposals to Either Expand or Eliminate the MARL

We adopted a MARL for mobilehome park master-meter customers who submeter in PG&E's 1990 general rate case (34 CPUC 2d 199, 352). The MARL is a safeguard to ensure against an excessive discount.

WMA and PG&E make proposals on the gas MARL in this BCAP which substantially duplicate their proposals on the electric MARL in A.88-12-005 (PG&E Electric Rate Design Window). PG&E proposes to include additional cost elements to expand the MARL. WMA recommends elimination of the MARL.

Briefs were filed on the MARL issue after the mailing of D.92-04-063 in A.88-12-005. In D.92-04-063 we declined to expand or eliminate the electric MARL, and stated that it may be considered further in PG&E's pending general rate case (A.91-11-036). Based on that decision, WMA recommends that further consideration of expansion or elimination of the gas MARL be deferred to PG&E's pending general rate case. In the alternative, WMA recommends eliminating the existing MARL.

PG&E argues that this record is adequate for Commission consideration of the MARL and repetition of the issue in the general rate case would be redundant and wasteful. Further, PG&E argues that at least one element of its proposal is exclusively a gas rate design issue. Specifically, treatment of shrinkage costs differs for core and noncore transport customers relative to bundled service customers on Schedules GT and GTL, according to PG&E. PG&E states that core and noncore transport customers pay shrinkage costs by providing shrinkage in kind. Thus, transport customers pay shrinkage costs even when the MARL is applied, PG&E asserts. PG&E claims that bundled service customers, however, do not now pay shrinkage costs when the MARL is applied because the current MARL for these customers does not include an amount to cover shrinkage. In reply, WMA argues Schedule GT rates already include shrinkage charges and to include them again constitutes a double charge.

We decline to make any changes to the gas MARL at this time. It would not be reasonable to adjust the gas MARL in this BCAP when we so recently declined to do so for the electric MARL based on virtually identical arguments. We will allow parties to make proposals in the rate design phase of PG&E's pending 1993 general rate case.

We decline to change the MARL because, as we reasoned in D.92-04-063, our treatment of the MARL depends on our treatment of the master-meter discount. We adopted the MARL because of concerns regarding possible inaccuracies in calculating the discount. The MARL balances the master-meter customers' entitlement to the discount against the utility's entitlement to limit the discount to the cost of providing comparable service to other customers. We directed PG&E in D.89-12-057 to develop a more accurate method of calculating the master-meter discount payment and to report the results in its next general rate case application. A complete record will be developed in the PG&E's 1993 general rate case.

Since we have deferred further consideration of the electric MARL to the general rate case, deferring further consideration of the gas MARL to the general rate case will establish a comprehensive forum to consider all aspects of the MARL in one proceeding. We will, however, adopt PG&E's proposal to extend the provisions of the gas MARL to Schedules GS and GSL, as we did for the electric MARL in D.92-04-063. This proposal was not opposed by any party, and it simply promotes consistent treatment among master-meter customers.

While we defer a comprehensive consideration of the MARL to the GRC, our decision to include shrinkage costs in the procurement rate has the effect of treating the one issue PG&E identified as an exclusively gas rate design issue. We are satisfied this treatment corrects an inequity between bundled service customers compared to core and noncore transport customers, while not imposing a double charge.

11.7 Bundled Commercial Service

Powerplant igniter-fuel volumes were previously allocated to Schedule G-NR1. PG&E proposes to allocate all forecast igniter-fuel volumes to Schedule G-NR2, since billing records show that over 99% of igniter-fuel volumes are billed under Schedule G-NR2. No party took issue with PG&E. We adopt PG&E's proposal.

11.8 Schedule GC-2

The "GC-2 revenue differential" is the difference between the Schedule GC-2 customers' otherwise-applicable transportation-only rate and the GC-2 rate multiplied by the forecasted GC-2 volumes. Currently, PG&E calculates the GC-2 revenue differential before allocating the low-income rate adjustment (LIRA) and Schedule G-10 subsidies. Since the allocation of these subsidies results in an increase in rates, the current method of calculating the GC-2 revenue differential does not measure the full difference between the GC-2 and otherwise-applicable rate schedules. PG&E proposes to correct the error by calculating the GC-2 revenue differential after adjusting for LIRA and Schedule G-10 subsidies. No party took issue with PG&E. We adopt PG&E's proposal.

12. Wholesale Issues

Throughput and bypass wholesale issues raised by Southwest are addressed elsewhere in this decision. The remaining wholesale issues are discussed here.

12.1 Cost Allocation

PG&E allocates costs to customer classes using four cost allocation factors. Wholesale class-allocated costs are then distributed by PG&E among its wholesale customers in the rate design process. In that process, PG&E distributes the wholesale revenue requirement to each wholesale customer using only one of the four cost allocation factors. The City of Palo Alto (Palo Alto) proposes that costs be distributed to the individual wholesale customers within the wholesale class based on all four allocation factors. Alternatively, Palo Alto proposes that each wholesale customer be treated as a separate class.

PG&E takes no position on Palo Alto's proposal, but recommends that if it is adopted, it be implemented by treating each wholesale customer as a separate class. Southwest objects to Palo Alto's recommendation, claiming it duplicates efforts to be undertaken in the LRMC proceeding, it is inconsistent with exclusion of similar cost allocation issues from this BCAP proceeding, and it results in preferential and discriminatory treatment to other customers not permitted to raise their own cost allocation issues. Southwest recommends deferring Palo Alto's proposal to the upcoming LRMC proceeding (I.86-06-005).

We adopt Palo Alto's recommended method for cost allocation. This approach reallocates less than 0.5% of wholesale costs among PG&E's wholesale customers. It applies the four factors used in class cost allocation consistently. While it may be unlikely for us to apply the four-factor allocation to end-use customers within classes, wholesale customers are not end-use customers.

Southwest's procedural objections are not persuasive. Southwest is correct that we have deferred many issues to the LRMC proceeding. Not all issues have been deferred, however. Palo Alto's proposal is not based on long-run marginal costs and will not duplicate efforts to be undertaken in the LRMC proceeding. Southwest contends consideration of Palo Alto's recommendation is inconsistent with Commission orders to exclude such cost allocation issues from BCAP proceedings. Southwest, however, neither moved to strike nor objected to the receipt in evidence of Palo Alto's testimony. Southwest claims it cancelled its own plans for presenting cost allocation testimony after motions to strike PG&E's proposals to alter cost allocation were granted. Southwest contends consideration of Palo Alto's testimony is therefore preferential and discriminatory to other customers. Southwest neither sought clarification of the granting of the motions to strike PG&E's testimony, nor offered its own testimony (which it could have defended against motions to strike). Significantly, it waited until the briefing stage to raise its concern regarding the scope of the proceeding.

We decline to implement wholesale allocation by treating each wholesale customer as a separate class. PG&E offered no reasons why each wholesale customer should be treated as a separate class. There is no difference in the results between Palo Alto's proposal and its alternate proposal. Wholesale customers are similar enough to be combined into one class. We see no reason to increase the number of classes.

12.2 Wholesale Core's Access to PG&E's Storage

Palo Alto recommends that when capacity brokering is implemented, the wholesale core storage entitlement should be based on each wholesale customer's share of storage costs allocated to retail and wholesale core customers. Palo Alto asserts wholesale customers should receive a core storage entitlement proportionate to the amount of storage costs allocated to wholesale core loads in PG&E's most recent cost allocation proceeding, citing D.88-11-034.

We decline to adopt Palo Alto's recommendation. Palo Alto's proposal reallocates benefits without reallocating costs, but we are not convinced that our current methodology should be changed. Moreover, Palo Alto's proposal is premised on adoption of capacity brokering, and Palo Alto made this same recommendation in R.88-08-018. Since we made no change in wholesale customers' core storage entitlement in D.92-07-025 (R.88-08-018, capacity brokering), we make no change here.

12.3 Rate Negotiations

Palo Alto urges the Commission to reiterate that wholesale customers have a right to negotiate their rate structure with PG&E. When asked, however, Palo Alto's witness could not recall if Palo Alto has attempted to negotiate with PG&E (Tr. 5:346).

PG&E agrees that wholesale customers may negotiate with PG&E for a mutually acceptable rate design. PG&E argues that wholesale customers do not have a unilateral right to any particular rate design other than that in authorized tariffs, however, and none should be granted in this proceeding.

We see no particular need to do anything more than note that, consistent with prior Commission decisions, wholesale customers and PG&E may negotiate a mutually acceptable rate design, but no customer has a right to any rate or rate design other than those in an authorized tariff.

13. Implementation

By this decision we authorize PG&E to file new tariffs. Consistent with the schedule for cost allocation proceedings established in D.89-01-040 and D.90-09-089, we direct PG&E to file its next BCAP application on August 16, 1993, with rates to become effective April 1, 1994. Any deviation from this schedule should be made by a petition for modification of D.89-01-040 and D.90-09-089, or a letter to the Executive Director, consistent with Rule 43.

14. TURN's Request for Finding of Eligibility for Compensation

On April 29, 1992, TURN filed a Request for Finding of Eligibility for Compensation, under Article 18.7 of the Commission's Rules of Practice and Procedure. No party responded to TURN's request.

The purpose of Article 18.7:

> "...is to provide compensation for reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs...of participation or intervention in any proceeding of the Commission initiated on or after January 1, 1985, to modify a rate or establish a fact or rule that may influence a rate."

This is a Commission proceeding initiated after January 1, 1985 to modify a rate or establish a fact or rule that may influence a rate. This proceeding therefore falls within the purpose of this article.

Rule 76.54(a) requires the filing of a request for eligibility within 30 days of the first prehearing conference or within 45 days of the close of the evidentiary record. TURN's request was filed within 45 days of the close of the evidentiary record.

Rule 76.54(a) requires that a request for eligibility include four items:

> (1) A showing by the customer that participation in the hearing or proceeding would pose a significant financial hardship. A summary of the finances of the customer shall distinguish between grant funds committed to specific projects and discretionary funds. If the customer has met its burden of showing financial hardship in the same calendar year, as determined by the Commission under Rule 76.05, 76.25, or 76.55, the customer shall make reference to that decision by number to satisfy this requirement;
>
> (2) A statement of issues that the customer intends to raise in the hearing or proceeding;
>
> (3) An estimate of the compensation that will be sought; and
>
> (4) A budget for the customer's presentation.

The adequacy of TURN's filing on each of these items is addressed below.

<u>14.1 Significant Financial Hardship</u>

TURN's request references that it has previously been found to have met its burden of showing financial hardship for calendar year 1991 in D.91-05-029. TURN states it has made its showing for calendar year 1992 in its Request for Finding of

Eligibility for Compensation filed January 27, 1992 in PG&E A.89-04-033 (PG&E/PGT Expansion Project), and that TURN expects a ruling on that request before a decision in this BCAP. D.92-10-056 finds TURN meets its burden for calendar year 1992. Therefore, we conclude that TURN has met the requirements of Rule 76.54(a)(1) and has shown that its participation in this proceeding would pose a significant financial hardship.

14.2 Statement of Issues

Rule 76.54(a)(2) requires a statement of issues that the party intends to raise. TURN states that the issues raised by it in this proceeding are already matters of record, particularly as set forth in its prepared testimony, briefs, and as a primary party to the proposed stipulation.

TURN addressed a wide variety of issues, including gas costs, demand, throughput, the discount adjustment, bypass, the revenue requirement, cost allocation, rate design, the alternate fuel requirement, a noncore peaking rate, and Transwestern demand charges. A review of the record and this decision provide clear evidence that TURN has complied with Rule 76.54(a)(2).

14.3 Estimate of the Compensation to be Sought

Rule 76.54(a)(3) requires an estimate of the compensation to be sought. TURN estimates it may request about $50,000 for its work in this case, based on an assumed 180 hours of attorney/witness Florio's time at a proposed hourly rate of $250, 25 hours of attorney Funkelstein's time at an hourly rate of $150, plus $1,250 for "other reasonable costs," primarily postage, and copying expenses. TURN has complied with Rule 76.54(a)(3).

14.4 Budget

Rule 76.54(a)(4) requires a budget for the party's presentation. TURN's estimated budget for this proceeding is $50,000, as discussed above.

TURN has complied with Rule 76.54(a)(4). The reasonableness of this estimate will be considered if and when TURN requests compensation in this proceeding.

14.5 Conclusion

TURN has met the requirements of Rule 76.54(a) for this proceeding. In addition, no party has responded to TURN's request. We find TURN to be eligible to request an award of compensation for its participation in this proceeding.

TURN is placed on notice that it may be subject to audit or review by the Commission Advisory and Compliance Division. Therefore, adequate accounting records or other necessary documentation must be maintained by the organization in support of all claims for intervenor compensation. Such record keeping systems should identify specific issues for which compensation is being requested, the actual time spent by each employee, the hourly rate paid, fees paid to consultants and any other costs incurred for which compensation may be claimed.

15. Updated Account Balances

Exhibit 36 provides updated revenue requirement and rate tables based on August 31, 1992 recorded balancing account balances. The update would increase the revenue requirement, and reduce the rate decrease, by over $100 million. PG&E argues, however, that this would serve no useful purpose.

The large impact is primarily due to the highly seasonal nature of the core fixed cost account (CFCA), according to PG&E. The undercollection in this account tends to grow in the summer (when core usage is less) and fall in the winter (when core usage is more). PG&E notes that even though earlier PG&E ACAP rates included seasonal adjustment, none was proposed in this proceeding. Moreover, previous PG&E ACAPs used estimated April 30 balances in setting rates, according to PG&E. PG&E recommends that in this proceeding rates be set using July 31, 1992 recorded data without further adjustment. PG&E argues this is appropriate given the two-year duration of these rates and the ability to make a trigger filing if necessary.

In its comments on Exhibit 36, DRA argues that April 30 balances have been used in past PG&E ACAPs and should be used for the CFCA here. This will amortize the systematic undercollection that has accrued in this account, according to DRA. Moreover, DRA asserts this will not burden customers with a high rate based on a relative seasonal peak undercollection which normal seasonal sales variation will cure. DRA avers that representatives of both PG&E and TURN agree to the use of the April 1992 CFCA balance. DRA further states that August 31 balances are acceptable for other accounts since they are less vulnerable to seasonal variations. By subsequent filing, PG&E states that it agrees with the use of the April 30, 1992 balance for the CFCA and the August 31, 1992 balances for other accounts.

We use the April 30, 1992 balance for the CFCA, and August 31, 1992 balances for all other accounts. The April CFCA balance more accurately reflects the undercollection that we seek to amortize while not basing rates on a relative seasonal peak undercollection. Using July balances for all other accounts produces an overall rate reduction less than one percent different than that derived from August balances. We use August balances to incorporate the most recent data. We encourage PG&E and the other parties to include seasonal adjustments in future BCAP rate recommendations where appropriate.

<u>Findings of Fact</u>

1. PG&E filed its first biennial cost allocation proceeding application on November 1, 1991.

2. By ALJ ruling, parties were allowed to include Transwestern pipeline contract costs in their recommended revenue requirement, specifically subject to refund based on a reasonableness determination in an appropriate future ECAC and with

the cost allocation subject to being superseded by the results of the capacity brokering proceedings (R.88-08-018, R.90-02-008).

3. Five parties entered into a stipulation to resolve between themselves many of the issues in this proceeding.

4. Stipulating parties agreed that the stipulation shall be null and void unless the Commission accepts the stipulation and its recommendations in their entirety, without change or condition.

5. California public policy favors settlement and the propriety of settlement in utility matters.

6. Despite public policy favoring settlement, the burden of proof remains with the parties advancing a stipulation or settlement to show that it is reasonable, consistent with law, and in the public interest.

7. Nonstipulating parties contest four elements of the stipulation: (1) allocation of storage costs, (2) allocation of the $7.3 million undercollection in the brokerage fee balancing account, (3) allocation of the $5.2 million overcollection in the noncore PGA, and (4) inclusion of Transwestern demand charges in rates.

8. The stipulated throughput forecast is reduced to reflect bypass over the Dow pipeline.

9. Upon rejection of a stipulation we may hold hearings, let parties renegotiate, propose alternative terms for the parties' consideration (Rule 51.7), or we may make a decision based on the record.

10. The stipulated treatment of Transwestern pipeline costs conflicts with D.92-07-025.

11. The stipulated allocation of the noncore PGA overcollection is unfair to those who purchased the gas, and differs from our treatment of a similar overcollection in the core-elect PGA in D.91-05-029.

12. The stipulation is incompatible with the public interest.

13. This record is substantial and ripe for decision, even though stipulating parties elected not to cross-examine each other.

14. PG&E's economic, petroleum product price, crude oil, and alternate fuel oil forecasts are reasonable.

15. DRA's residential and commercial core gas throughput forecasts exceed those of PG&E in large part due to DRA's forecast of a lower gas price.

16. Residential and commercial throughput forecasts approximately halfway between PG&E's and DRA's original estimates are reasonable since we adopt a gas price approximately halfway between PG&E's and DRA's original estimates.

17. PG&E's estimates are reasonable for core interdepartmental, UEG igniter fuel and NGV throughput, and are not in dispute between the parties.

18. Our adopted gas price forecast reduces the difference between PG&E's and DRA's industrial throughput forecast.

19. PG&E's estimate of industrial throughput is reasonable when modified to both reflect the recalculation of the cogeneration backout, and to include 4.8 MMdth for customer loads switching back to natural gas.

20. PG&E sales to SCE's Cool Water plant are uncertain since SCE may bypass PG&E and buy gas from SoCal.

21. A throughput forecast of 2 MMdth per year to Cool Water is reasonable as a conservative estimate since total bypass is not certain.

22. DRA disputes PG&E's cogeneration forecast only over the exclusion of gas demand for one cogeneration project during the months of January, February, and March of 1992 and 1993.

23. PG&E's forecast of cogeneration throughput, adjusted for the exclusion of gas demand from one project as recommended by DRA, is reasonable.

24. PG&E's forecasts for EOR, industrial interdepartmental, and steam heat sales are reasonable.

25. Both PG&E and DRA forecast 14.6 MMdth per year bypass of PG&E's gas department by PG&E's electric department.

26. It is not reasonable to include UEG bypass in the throughput forecast since it is not now occurring and the forecast should not prejudge whether this bypass should or should not occur.

27. DRA's UEG forecast is reasonable when adjusted to eliminate UEG bypass, since it is based on the most recent data.

28. PG&E's wholesale forecast is reasonable when adjusted to reflect the bankruptcy of Luz.

29. PG&E's throughput forecast assuming 8.8 MMdth per year for PG&E customers served by the Dow pipeline is inconsistent with D.85-07-029.

30. Including Dow bypass would shift the risk of revenue loss to ratepayers.

31. Elimination of Dow bypass in the forecast properly allocates the risk of bypass and provides PG&E with an incentive to resolve this matter.

32. PG&E's shrinkage estimates are reasonable.

33. PG&E's estimates of curtailments are reasonable without Cool Water curtailment since only a small throughput is estimated to Cool Water, only a small portion of which would occur in the winter months when curtailments are typical.

34. A throughput forecast which rejects estimates of Dow, UEG, and Southwest bypass needs no special tracking accounts, balancing accounts, or ratemaking treatments as contained in the stipulation.

35. Rejection of the stipulation relieves PG&E of the provision in the stipulation requiring it to file a complaint at the Commission against Dow.

36. PG&E's wholesale demand charge is justified since PG&E must include wholesale customer core volume in PG&E's system planning requirements.

37. Southwest is not bound by the stipulation provision to file an application before it bypasses PG&E's service, but nothing in our rejection of the stipulation prevents Southwest from filing a complaint.

38. Given PG&E's wholesale demand charges, Southwest is effectively foreclosed from bypassing PG&E's service during the test period unless Southwest files a complaint which would allow that result and the requested relief is granted.

39. A WACOG of $1.825 per decatherm for the BCAP period, calculated using the rates in effect approach, is reasonable.

40. The inclusion of shrinkage costs in the procurement rate is consistent with the inclusion of future shrinkage costs for PG&E's procurement customers as a cost of gas in the PGA.

41. PG&E's methods for developing the revenue requirement are reasonable except with regard to the noncore shrinkage tracking account, shareholder recovery of the overcollection in the noncore PGA, inclusion of Transwestern demand charges and core gas transport rules, with our adopted throughputs, WACOG and procurement rates.

42. Treating the $7.0 million undercollection in the shrinkage tracking account as though it had been recorded in the noncore fixed cost account is consistent with the approach last adopted and is reasonable.

43. Recording future core-subscription shrinkage costs for PG&E's procurement customers as a cost of gas in the PGA is reasonable because core-subscription shrinkage costs are costs of gas bought for those noncore customers who purchased gas from PG&E, while customers who procure their own gas already pay their shrinkage costs by providing shrinkage in kind.

44. Partial balancing account treatment for future shrinkage costs is reasonable because it prevents the utility from bearing the full impact of fluctuations in the noncore shrinkage tracking account while still providing PG&E an incentive to minimize shrinkage costs.

45. Given our actions to limit the role of utilities in noncore customer procurement, it is reasonable to continue the balancing account treatment for the brokerage fee balancing account, thereby avoiding placing PG&E in the position where its

primary opportunity to fully recover its costs and contribute to earnings is to maximize gas sales to noncore customers.

46. Given our directions in D.86-12-010 and D.87-12-039 that utilities charge noncore procurement customers the WACOG with frequent adjustments to correct inaccuracies in prior months' WACOG estimates, PG&E's shareholders were at no risk from the noncore PGA as long as PG&E provided a service which reasonably met the Commission policy of offering a cost-based, best efforts portfolio of spot gas supplies.

47. The definition of memorandum account in PG&E's preliminary statement does not make clear whether shareholders or ratepayers will ultimately be responsible for any undercollection or overcollection in the noncore PGA.

48. In each of the 10 months after our decision to terminate noncore portfolio service (D.90-09-089), PG&E overcollected from its noncore portfolio customers, converting a $4.5 million undercollection in September 1990 into a $5.2 million overcollection when the account was terminated and final entries booked.

49. We authorized and intended PG&E to adjust the WACOG price up to twice a month to eliminate under- or overcollections in the noncore PGA.

50. Given the way we intended the noncore PGA to operate and PG&E's ability to carry out our intent, it cannot be said that PG&E's shareholders bore the risk of the final noncore PGA balance.

51. It is reasonable to exclude Transwestern pipeline demand charges from the revenue requirement based on our decision to do so in D.92-07-025.

52. Inclusion of Transwestern pipeline costs in PG&E's balancing account, with PG&E's ability to separately identify all Transwestern and related charges and interest, obviates the need to track Transwestern charges in a separate interest bearing memorandum account.

53. Truing-up the core direct-billed take-or-pay account every two years rather than annually is consistent with biennial

review of all other accounts and allows the utility an opportunity to earn its authorized rate of return (since the account can be expected to be undercollected in the first year and overcollected in the second year).

54. D.91-02-040 provides that transportation rates for core customers who qualify for transportation-only service are adjusted for the first year of transport service to include a component that reflects the balances in the core PGA, while under the BCAP, the core PGA will be amortized over two years.

55. We decline to amortize the core PGA overcollection over one rather than two years, in order to avoid two sets of BCAP rates and because there will be approximately only 18 months in this BCAP cycle.

56. A refund of the core PGA overcollection would disturb our policy of amortizing over- or undercollections (for rate stability) to meet the needs of very few transport customers at the expense of impacting the majority of core customers.

57. The circumstances justifying the refund of the core-elect PGA and the noncore PGA overcollections (i.e., the change in our regulation and the termination of the account) differ from the circumstances surrounding the core PGA, an account which will continue.

58. It is reasonable to adopt rules for core transport service to match amortization of the core PGA overcollection with the period of these BCAP rates.

59. It is not possible to design a rule that perfectly matches the return of the overcollection in the core PGA to those who paid the excess while at the same time neither being unfair nor creating skewed incentives for customers to switch between core and core transport service.

60. It is reasonable to direct the amortization of the core PGA only in relation to the schedules from which customers took service on August 1, 1992 to mitigate customer switching for the purpose of participating in the refund.

61. It is reasonable to adopt zero noncore discounting, with the exception of Cool Water, based on the agreement between the parties that forecast discounting should be zero, and based on our adopted natural gas and alternate fuel price forecast.

62. It is reasonable to forecast PG&E sales to Cool Water at $0.03 per therm based on the $0.03 per therm volumetric rate in SoCal's contract with SCE.

63. Rerunning the discount adjustment model whenever base revenues are revised would add needless complexity to already difficult or focused proceedings for adjustments which are likely to be small, and would miss other factors which may cause PG&E to overcollect revenues relative to the BCAP forecast.

64. Rerunning the discount adjustment would provide another layer of risk protection for PG&E shareholders, contrary to our general gas restructuring policy to shift risks onto the company's shareholders as we create a competitive marketplace.

65. Storage provides benefits to noncore customers, including at least the provision of total gas system load balancing, the improvement of pipeline utilization, and the improvement of gas service reliability.

66. Any benefits obtained by participation in the pilot storage program are in addition to the three or more benefits of storage generally provided all customers, including noncore.

67. All customers who use the system during peak periods benefit from the increased system capacity that storage provides, not just customers whose loads vary by season.

68. The 10% noncore transportation load imbalance tolerance does not sufficiently capture cost incurrence to justify its sole use in allocating storage cost.

69. It is reasonable to recover the $7.3 million undercollection in the brokerage fee balancing account from all noncore customers, including core subscription customers, since the undercollection results from a variation between the forecast core-elect and noncore portfolio sales volume in PG&E's 1991 ACAP

and the actual volume purchased by core subscription customers, primarily occurring after August 1, 1991.

70. The undercollection in the brokerage fee balancing account is a result of core subscription customers transferring to noncore service, not core customers being allocated brokerage fee revenues in a prior proceeding.

71. It is reasonable to return the overcollection in the noncore PGA to those noncore customers who purchased gas accounted for in the noncore PGA in the months of May through July, 1991.

72. The stipulation would allocate the noncore PGA overcollection to all noncore customers, thus allocating the overcollection to noncore customers who did not purchase noncore portfolio gas during the period when the final overcollection was accumulated.

73. Refunding the noncore PGA overcollection to certain customers does not conflict with our policy against retroactive rate adjustments since the account has now terminated and any concern about applying adjustments retroactively as an ongoing principal guiding account operation no longer applies.

74. Fairness dictates that those customers who actually paid the noncore PGA overcollection are due the refund.

75. The undercollection in the noncore PGA before May 1991 became an overcollection by the end of May 1991.

76. Between May and July 1991, the noncore PGA accumulated an overcollection of $5.2 million, including final entries into the account.

77. PG&E has a fiduciary duty to responsibly manage money in its possession.

78. There was no intention with noncore PGA termination that PG&E would finance a deficit at its own cost, get an interest-free loan, or get to keep the return from investing the balance.

79. It is reasonable to adopt PG&E's recommendations that the remaining balance in the natural gas vehicle pilot program account be allocated to all customers on an equal cents-per-therm basis, that the balance in the noncore fixed cost account be allocated to

all noncore customers on an equal cents-per-therm basis, that the customer energy efficiency account balance be allocated according to weighted number of customers across all classes (consistent with the method used to allocate customer energy efficiency program costs), and that any balance in the firm surcharge/interruptible credit account be included in the determination of the interruptible credit.

80. It is reasonable to eliminate the necessity for core customers to apply for and pass the economic practicality test in order to qualify for noncore status.

81. It is reasonable to establish a tracking account for customers transferring to noncore status after August 1, 1991, to record unforecasted rate impacts on the core class.

82. At adopted rates, the penalty of $16 per therm for a noncore customer failing to curtail when requested makes the customer worse off after 72 hours of failing to curtail compared to the customer paying core rates.

83. The penalty of $1 per therm for a noncore customer failing to curtail leaves the noncore customer better off at adopted rates by failing to curtail for up to 49 days and paying the penalty compared to paying core rates.

84. It is reasonable to calculate the penalty for failure to curtail based on the relationship between noncore and core rates, since noncore customers should become core customers if they require greater reliability.

85. Noncore customers effectively enjoy core service if they fail to curtail when requested.

86. If noncore customers fail to curtail when requested, they not only negatively impact core rates, but they both enjoy the equivalent of core service without paying its costs and jeopardize core service to all core customers.

87. It is reasonable to reassign to the appropriate core rate schedule those noncore customers who show a pattern, or reasonable expectation, of failing to curtail, thereby avoiding giving a

preference or advantage to the noncore customer relative to other customers.

88. A 24-hour grace period before the penalty for failure to curtail would begin would not allow PG&E to satisfactorily operate its system and would be an intolerable burden on the reliability of core service.

89. The penalty for noncurtailment should attach only after a customer has been notified of the curtailment.

90. It is reasonable to apply either 100 Mcf per peak day or 20,800 therms per active month usage as the minimum size requirement to be eligible for noncore status.

91. It is reasonable to suspend implementation of eliminating the alternate fuel requirement, eliminating the economic praticality test, increasing the penalty for failure to comply with a curtailment order, and modifying the size requirement for noncore status pending further review in R.86-06-006.

92. It is reasonable to adopt a residential gas rate design policy in this BCAP since BCAPs are the proceedings in which we consider gas rate design.

93. It is reasonable to include the CPUC fee in the UEG-cogeneration rate parity calculation, consistent with our past practice in PG&E proceedings, since the CPUC fee paid by cogenerators is not analogous to a utility tax.

94. It is reasonable to exclude UEG igniter fuel in the UEG-cogeneration rate parity calculation since UEG igniter fuel is a core service and is not properly included in either UEG noncore rates or noncore cogeneration rates.

95. It is reasonable to adopt PG&E's recommendation regarding future changes in service level nominations for UEG and wholesale customers.

96. It is reasonable to adopt WMA's recommendation to recalculate the diversity adjustment to the discount received by master-meter customers who submeter based on our adopted residential rates using PG&E's 1993 general rate case diversity adjustment model.

97. It is reasonable to decline to make any changes in the gas MARL (with the exception of shrinkage costs) for the same reasons we declined to changed the electric MARL in D.92-04-063.

98. It is reasonable to adopt PG&E's proposal to extend the provisions of the gas MARL to Schedules GS and GSL since this proposal promotes consistent treatment among master-metered customers.

99. Including shrinkage costs in the procurement rates has the effect of addressing the inequity between bundled service customers compared to core and noncore transport customers, while at the same time not being a double charge.

100. PG&E's proposal to allocate all forecast igniter-fuel volumes to G-NR2 is unopposed and is reasonable since over 99% of igniter fuel volumes are billed under Schedule G-NR-2.

101. PG&E's proposal to calculate the Schedule GC-2 revenue differential after adjusting for LIRA and Schedule G-10 is reasonable.

102. Wholesale customers are similar enough to be combined into one class.

103. Palo Alto's wholesale core storage entitlement proposal reallocates benefits without reallocating costs.

104. Palo Alto's wholesale core storage entitlement proposal is premised on adoption of capacity brokeing, Palo Alto made its proposal in R.88-08-018, and its proposal was not adopted in D.92-07-025.

105. TURN has met the full requirements of Rule 76.54(a) for this proceeding.

106. The CFCA is particularly sensitive to seasonal variations.

107. Using the April 30, 1992 CFCA recorded balancing account balance amortizes the undercollection which has accrued in this account without basing rates on a relative seasonal peak undercollection.

108. The overall revenue reduction using July 31, 1992 rather than August 31, 1992 recorded balancing account balances differs by less than one percent.

109. It is reasonable to use the April 30, 1992 recorded balancing account balances for the CFCA, and August 31, 1992 recorded balancing account balances for all other accounts.

<u>Conclusions of Law</u>

1. A stipulation should not be approved, whether contested or uncontested, unless the stipulation is reasonable in light of the whole record, consistent with law, and in the public interest, and, despite public policy favoring settlement, unless the stipulating parties carry their burden of proof.

2. The stipulation in this proceeding should be rejected since it is inconsistent with prior Commission decisions, is unfair to noncore PGA customers who took service during May through July 1991, and is therefore unreasonable, inconsistent with law, and not in the public interest.

3. The residential and commercial throughput forecasts contained in Appendix D should be adopted.

4. PG&E's estimates of core interdepartmental, UEG igniter fuel, NGV, EOR, industrial interdepartmental, and steam heat throughput should be adopted.

5. PG&E's estimate of industrial throughput modified by both the recalculation of the cogeneration backout and 4.8 MMdth for customer loads switching back to natural gas should be adopted.

6. A throughput forecast of 2 MMdth per year for Cool Water should be adopted.

7. PG&E's cogeneration forecast, adjusted for the gas demand of one project during the months of January, February, and March in 1992 and 1993, should be adopted.

8. DRA's estimate of UEG demand, without reduction for UEG bypass, should be adopted.

9. PG&E should justify its decision to either bypass or not bypass some portion of its UEG load in the future ECAC proceedings

which cover the record periods from August 1, 1992 through July 30, 1994.

10. PG&E's forecast for wholesale throughput, adjusted to reflect the effects of the Luz bankruptcy, should be adopted.

11. PG&E's industrial and cogeneration demand forecasts should be increased by 5.2 MMdth and 3.7 MMdth, respectively, to remove the effect of the Dow bypass.

12. The cold year throughput and curtailments in Appendix D should be adopted, being consistent with the adopted average year demand forecast without Cool Water curtailment.

13. PG&E should justify in its next ECAC proceeding whatever action PG&E takes or does not take with regard to the Dow bypass.

14. A WACOG of $1.825 per decatherm for the BCAP period should be adopted.

15. Shrinkage costs should be included in our calculation of the procurement rate.

16. The $7.0 million balance in the shrinkage tracking account should be recorded in the noncore fixed cost account.

17. Future core subscription shrinkage costs for PG&E's procurement customers should be recorded as a cost of gas in the PGA.

18. PG&E should be at risk for part of the future shrinkage cost balancing account to mitigate PG&E from carrying the full impact of fluctuations while providing PG&E an incentive to minimize shrinkage costs.

19. We should continue the balancing account treatment for the brokerage fee balancing account.

20. The $5.2 million overcollection in the noncore PGA should be returned to customers.

21. Transwestern demand charges should be excluded from rates but reported in PG&E's balancing account subject to future reasonableness review and allocation, consistent with D.92-07-025.

22. The core direct billed take-or-pay account should be trued-up biennially.

23. Rules should be adopted for gas transport service to match the amortization of the core PGA overcollection with the period of these BCAP rates, to ensure customers transferring to and from core and core transport service after August 1, 1992 receive their appropriate share of the $143 million overcollection.

24. The discount adjustment model should not be rerun whenever base revenues are revised.

25. Storage costs should be allocated based on the current Commission approval methodology (cold year peak season throughput), and parties should focus creditable, comprehensive studies on further storage costs allocation analysis in I.87-03-036.

26. The $7.3 million undercollection in the brokerage fee balancing account should be recovered from all noncore customers, including core subscription customers.

27. The $5.2 million overcollection in the noncore PGA should be returned with interest to those noncore customers who purchased gas accounted in the noncore PGA in the months of May through July 1991.

28. The remaining balance in the natural gas vehicle pilot program account should be allocated to all customers on an equal cents-per-therm basis, the balance in the noncore fixed cost account should be allocated to all noncore customers on an equal cents-per-therm basis, the customer energy efficiency account balance should be allocated according to weighted number of customers across all classes and any balance in the firm surcharge/interruptible credit account should be included in the determination of the interruptible credit.

29. The alternate fuel requirement for noncore status qualification should be eliminated, as should the economic feasibility test; the penalty for failure to comply with a curtailment order should be increased to $16 per therm; customers

who show a pattern, or reasonable expectation, of failing to curtail should be moved to the appropriate core rate schedule; the rules for penalty application should be retained; the minimum size requirement for noncore status should be either 100 Mcf per peak day or 20,800 therms per active month; and existing noncore customers should remain noncore if they are below the new size requirements.

30. These changes should be suspended pending further consideration and review in R.86-06-006.

31. The residential gas rate design policy described herein should be adopted.

32. The UEG-cogeneration parity rate calculation should include the CPUC fee and exclude UEG ignitor fuel.

33. PG&E should file an advice letter at the time new service level nominations are made to change the fixed demand charge component of UEG and wholesale rates to reflect any changes in service level nominations, with revenues and credits due to the new service level nominations tracked in the firm surcharge/interruptible credit account.

34. The diversity adjustment to the discount for master-metered customers who submeter should be recalculated based on the adopted residential rates using PG&E's 1993 general rate case diversity adjustment model.

35. No changes should be made to the gas MARL in this BCAP, except to the extent the shrinkage cost treatment impacts the MARL.

36. The gas MARL should be extended to Schedules GS and GSL.

37. Forecast igniter-fuel volumes should all be allocated to Schedule G-NR2.

38. The Schedule GC-2 revenue differential should be calculated after adjusting for LIRA and Schedule G-10 subsidies.

39. The four factors using for overall class cost allocation should be used to allocate costs within the wholesale class to wholesale customers.

40. The existing method of determining wholesale core storage entitlement should be retained.

41. PG&E should file its next BCAP application on August 16, 1993, with rates to become effective April 1, 1994, consistent with the schedules for cost allocation proceedings established in D.89-01-040 and D.90-09-089.

42. TURN should be found eligible under Article 18.7 of our rules to claim compensation for its participation in this proceeding.

43. PG&E's BCAP rates should be based on the April 30, 1992 CFCA recorded balance, with all other balancing accounts based on August 31, 1992 recorded balances.

44. This order should be made effective today in order to place the new rates in effect as soon as possible.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall file, in accordance with General Order 96-A, tariff changes which implement the rules and rates adopted in this decision, and which are shown in Appendixes G and H, using the revenue requirement shown in Appendix F.

2. The revised tariff schedules shall be filed no later than 5 days after the effective date of this decision, with the revised tariff schedules to be effective no later than 3 days after being filed.

3. Adopted annual and monthly throughput amounts are contained in Appendix D.

4. PG&E shall justify its decision to either bypass or not bypass some portion of its utility electric generation load in the energy cost adjustment clause proceedings which cover the record periods from August 1, 1992 through July 30, 1994.

5. PG&E shall justify in its next energy cost adjustment clause proceeding application whatever action PG&E takes or does not take in regard to the Dow Chemical Company pipeline bypass.

6. PG&E shall conform its accounting treatment to the decisions contained herein for shrinkage costs, the brokerage fee balancing account, Transwestern Pipeline Company demand costs, and the core direct billed take-or-pay account.

7. PG&E shall institute of a refund of the $5.2 million overcollection in noncore purchased gas account with interest at the rate earned on 3-month commercial paper, as reported in the Federal Reserve Statistical Release, G.13, or its successor, from August 1, 1991 until the payment is made, in compliance with the discussion in this decision. The refund shall be based on each customer's use of gas accounted for in the noncore purchased gas account in May through July 1991, shall be calculated by an equal cents-per-therm method over the whole period, and shall be issued as a credit on the bill of each eligible customer. The refund shall be implemented within 120 days from the effective date of PG&E's revised tariff schedules filed pursuant to this decision.

8. The residential gas rate design policy discussed in this decision shall be adopted.

9. The alternative fuel requirement for noncore schedule eligibility and the economic practicality test shall be eliminated; the penalty for a noncore customer's failure to comply with a curtailment request shall be $16 per therm; customers who show a pattern, or reasonable expectation, of failing to curtail when requested shall be moved to the appropriate core rate schedule; the minimum size requirement for noncore status shall be either 100 Mcf per peak day or 20,800 therms per active month; and existing noncore customers shall remain noncore at their choice if they are below the size requirements until further order. The changes in this ordering paragraph are suspended pending further consideration and review in R.86-06-006.

10. PG&E shall establish a tracking account for customers transferring from core to noncore status after August 1, 1991, which will accrue the difference between the amount these transferring customers have paid and what they would have paid if billed at core rates. PG&E's next biennial cost allocation proceeding (BCAP) will address the issue of whether and in what matter the outstanding balance in this tracking account will be allocated to customers.

11. PG&E shall file an advice letter at the time new service level nominations are made to change the fixed demand charge component of the utility electric generation and wholesale rates to reflect any changes in the service level nominations.

12. PG&E shall file its next BCAP application on August 16, 1993, with rates to become effective April 1, 1994.

13. Toward Utility Rate Normalization is eligible to request compensation for its participation in this proceeding.

14. This proceeding remains open for the purpose of considering Toward Utility Rate Normalization's request for compensation, and for implementing changes which may be directed in R.86-06-006.

This order is effective today.

Dated October 21, 1992, at San Francisco, California.

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

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

APPENDIX A
Page 1

List of Appearances

Applicant: Harry W. Long, Jr., Mark Huffman, and Annie Tillery, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael P. Alcantar and Paul Kaufman, Attorneys at Law, for Cogenerators of Southern California; Barbara Barkovich, for Barkovich & Yap; R. Thomas Beach, for Luz Partnership Management; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Messrs. Morrison & Foerster, by Jerry Bloom, Lynn Haug, and Kevin D. DeBre, Attorneys at Law, for California Cogeneration Council; Messrs. Knox, Lemmon & Brady, by Matthew V. Brady, Attorney at Law, for State of California, Department of General Services; Rand Carroll, Attorney at Law, for State of New Mexico; E. G. Dittmer, for Petro Canada Resources; Charles Doering, for McFarland Energy Company; Phillip D. Endom, Attorney at Law, Susan Gibson and Phyllis Huckabee, for El Paso Natural Gas Company; Michel Peter Florio, K. Justin Reidhead, Thomas J. Long, and Robert Finkelstein, Attorneys at Law, for Toward Utility Rate Normalization; David B. Follett and E. R. Island, Attorneys at Law, for Southern California Gas Company; Steven M. Harris, for Transwestern Pipeline Company; Michael Hopkins, for City of Glendale; Adrian J. Hudson, for California Gas Producers Association; Messrs. Brady & Berliner, by John Jimison, Attorney at Law, for Independent Petroleum Association of Canada; Carolyn Kehrein, for Procter & Gamble Manufacturing Company; Messrs. Luce, Forward, Hamilton & Scripps, by John Leslie, for California Gas Marketers Group; Robert H. Mackie, for PanCanadian Petroleum Limited; Mesrs. Sutherland, Asbill and Brennan, by Keith McCrea, Attorney at Law, for California Industrial Group, California League of Food Processors, and California Manufacturing Association; Greg McGillivray, for Alberta Petroleum Marketing Commission; Keith Melville, Attorney at Law, and Beth Bowman, for San Diego Gas & Electric Company; Melissa Metzler, for Bakarat & Chamberlin; Joseph G. Meyer, for Joseph Meyer Associates; Messrs. Jones, Day, Reavis & Pogue, by Norman A. Pedersen, Attorney at Law, for Southern California Utility Power Pool; Robert L. Pettinato, for Los Angeles Department of Water & Power; Stephen E. Pickett, Bruce A. Reed, and Annette Gilliam, Attorneys at Law, for Southern California Edison Company; Edward G. Poole, Attorney at Law, for Anderson, Donovan & Poole; Patrick J. Power, Attorney at Law, for Sacramento Municipal Utility District; John D. Quinley, for Cogeneration Service Bureau; Sheldon D. Reid, for North Canadian

APPENDIX A
Page 2

Marketing, Inc.; Ariel Pierre Calonne, City Attorney, and Andrew Safir, for City of Palo Alto; Donald W. Schoenbeck, for Regulatory and Cogeneration Services; Andrew J. Skaff, Attorney at Law, for KES Kingsburg, L.P.; E. M. Small, for Suncor, Inc.; Mesrs. Armour, Goodin, Schlotz & MacBride, by James D. Squeri and Regina De Angelis, Attorneys at Law, for Kelco Division of Merck & Company, Inc.; Ronald V. Starsi, for City of Burbank; Alex Szabo, for City of Pasadena; Bruce Tulloh, for United States Department of the Navy; Roger Vaultoy, for M-S-R Public Power Agency; John C. Walley, Attorney at Law, Thomas R. Sheets, and Robert M. Johnson, for Southwest Gas Corporation; Robert B. Weisenmiller, for MRW & Associates; Kevin D. Woodruff, for Henwood Energy Services, Inc.; E. D. Yates, for California League of Food Processors; Jay E. Yount, for Chevron U.S.A., Inc.; Lina M. Hale, for Aebi Nurseries; Victoria Simmons, for Edson & Modisette; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; and Messrs. Wright & Talisman, by Jerome Candelaria, Attorney at Law, for McFarland Energy, Inc.

Protestant: Ronald A. Enomoto, for California Cut Flower Commission.

Division of Ratepayer Advocates: Carol Matchett, Attorney at Law, Larry Klapow, Brian Schumacher, and Natalie Walsh.

(END OF APPENDIX A)

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 August 1, 1992, pursuant to Decision Nos. 87-12-039, 89-01-040, 89-05-073, 90-04-021, 90-09-089, and 91-05-029. (U 39 G)	APPLICATION NO. 91-11-001

STIPULATION BETWEEN PACIFIC GAS AND ELECTRIC COMPANY, THE DIVISION OF RATEPAYER ADVOCATES, TOWARD UTILITY RATE NORMALIZATION. SOUTHWEST GAS CORPORATION, AND THE WESTERN MOBILEHOME ASSOCIATION

The parties to this stipulation (Stipulation) are Pacific Gas and Electric Company (PG&E), the Division of Ratepayer Advocates (DRA), Toward Utility Rate Normalization (TURN), Southwest Gas Corporation (SWG), and the Western Mobilehome Association (WMA).

PG&E, DRA, TURN, SWG, and WMA are collectively referred to herein as the "Parties", and each may be individually referred to herein as a "Party."

The Parties have entered into this Stipulation to resolve among themselves many of the issues in PG&E's Application No. 91-11-001, PG&E's 1992-1994 test period BCAP proceeding.

The Parties believe that this Stipulation is a reasonable compromise of their opposing positions.

Therefore, the undersigned Parties, through their attorneys of record in this proceeding, agree in this Stipulation to jointly support the recommendations described below for resolution of issues in this proceeding and to jointly urge the adoption of these recommendations in their entirety in this proceeding by the California Public Utilities Commission (Commission).

I.

ISSUES NOT COVERED BY THE STIPULATION

Although this Stipulation addresses the vast majority of issues whose resolution is required to establish rates, it does not resolve all issues. Some issues are not addressed. Others are addressed, but appear to be opposed by one or more of the non-settling parties. The unresolved issues can be grouped into seven categories:

1. Alternate fuel requirements for noncore status, and the noncurtailment penalty;
2. QF issues;
3. Revenue requirement issues;
4. Storage cost allocation issues;
5. Other cost allocation issues;
6. Wholesale rate design issues; and
7. Retail rate design issues.

Attachment A to this Stipulation contains a list of issues raised in this proceeding that have not been wholly resolved by this Stipulation.

II.

RECOMMENDATIONS

A. Total Revenue Requirement and Rates

The recommendations presented in Sections B through I below, result in a revenue requirement decrease of $291.7 million over the two year test period when compared to revenues that would be collected at present rates, as indicated in Table 4 attached to this Stipulation. The rates shown in Table 6 result from (1) the revenue requirement presented in Table 4, (2) the throughput forecasts presented in Tables 2 and 3 and (3) the recommendations presented in Sections B through I below.

Except as expressly stated in Sections B through I below, those assumptions necessary for the derivation of revenues at present rates, the revenue requirement and/or of rates are as set forth in PG&E's Prepared Testimony, as modified by PG&E's Updated Testimony. The Parties recommend that, with the exception of the issues not addressed by this Stipulation, outlined above and set forth in Attachment A, the Commission accept those assumptions which are embodied in Tables 1 through 6. With respect to any issues raised in this proceeding the resolution of which is not necessary for the derivation of revenues at present rates, the revenue requirement and/or of rates, the Parties recommend that no assumptions be adopted, except as recommended below in Sections B through I.

The revenue requirement table and the resulting rate table do not represent the final rates the Commission would implement by adopting this Stipulation. One component of the Stipulation is that the Parties recommend that the revenue requirement be updated in general accordance with PG&E's update proposal set forth in Chapter 1 of PG&E's Prepared Testimony. However, as part of this Stipulation, PG&E agrees to serve on all parties to this proceeding a draft of the Update Exhibit, not including the most current balancing account balances, within seven days after the mailing of the Proposed Decision, which will provide 13 days for review before the Update Exhibit is served. PG&E agrees not to make any substantive changes between the draft and final Update Exhibit, except for estimates of balancing account balances, without consulting with DRA.

B. Oil Price and Alternate Fuel Price

The Parties recommend that the Commission adopt the Refiners' Acquisition Cost of Crude (RACC) and alternate fuel prices reflected in Table 1. The alternate fuel prices are incorporated into the discount adjustment model discussed in Section G.

C. Gas Demand and Throughput

The Parties recommend the adoption of the gas demand, curtailment, and resulting throughput forecasts reflected in Tables 2 and 3 for the first and second years, respectively, of the BCAP test period. Monthly levels of demand have been derived from Tables 2 and 3 by scaling, using the monthly estimates of demand provided in PG&E's Updated Testimony.

D. UEG and Dow Pipeline Bypass

The bypass forecasts for both UEG and the Dow pipeline reflect the status quo. UEG bypass is not currently occurring and so is not reflected in the throughput forecast, while the Dow pipeline bypass is occurring and so is reflected in the throughput forecast.

With respect to the potential UEG bypass associated with the Steelhead pipeline, PG&E agrees to file an application requesting Commission authorization before beginning to take this service. If the Commission issues a decision approving PG&E's application, for each month thereafter for the remainder of the BCAP test period PG&E's UEG total monthly demand charges will be reduced by the ratio of the estimate of that month's bypass developed in the authorization application to that month's UEG throughput adopted in this proceeding. The demand charge reduction will be recorded in a balancing account, to be recovered from all customers, based on cold year throughput, in PG&E's next cost allocation proceeding.

With respect to the Dow pipeline bypass, PG&E agrees to file a Commission complaint against Dow, alleging that Dow's actions in connection with the Dow pipeline bypass constitute a business affected with the public interest and impressed with a public use. If Dow completely ceases to transport natural gas for others, either in response to a Commission order, voluntarily, or for any other reason, for so long as Dow transports no gas for others PG&E will record in the balancing account the revenues received from PG&E's customers with premise numbers 1043410, 0673599 and 4507589 for transportation service from PG&E up to 24.4 MDth per day, to be returned to all customers, based on cold year throughput, in PG&E's next cost allocation proceeding.

E. Gas Cost

The Parties recommend a forecast of $1.825 per decatherm for the gas portfolio WACOG for each year of the test period. These values do not include franchise fees and uncollectible accounts expense, brokerage fees, balancing account amounts or shrinkage.

F. Revenue Requirement

The Parties recommend that the balance in the noncore shrinkage tracking account be treated as though the entries had been recorded in the noncore fixed cost account.

The Parties recommend that in the future shrinkage costs for PG&E's procurement customers be recorded as a cost of gas, in the Purchased Gas Account, except that the Parties recommend that PG&E should be at risk for the noncore portion of the variation between recorded shrinkage costs and recorded shrinkage revenues to the same extent that it is at risk for the variation of revenues in the noncore fixed cost account. Currently, PG&E is at risk for 10% of this variation. Absent further Commission action, PG&E will be at risk for 25% of this variation beginning in May of 1992.

The Parties recommend that the core direct-billed take-or-pay one-way balancing account be trued up biennially, consistent with holding cost allocation proceedings biennially.

The Parties recommend that the balance in the Brokerage Fee balancing account be recovered from the entire noncore, and that the Brokerage Fee balancing account remain in effect during the BCAP test period. The Parties agree that the brokerage fee issue should be fully studied and reexamined in the next BCAP, in order to reflect the changes currently under way in the California gas market.

The Parties recommend that if the Commission adopts DRA's recommendation that ratepayers receive the final balance in the noncore PGA, then the Commission should also adopt DRA's recommendation to provide the balance to all noncore customers by crediting the noncore gas fixed cost account.

G. Discount Adjustment

The Parties recommend that the Commission adopt a 100% discount adjustment factor (no discounting) for the G-IND class excluding Cool Water, and for the G-COG class.

The Parties recommend that revenues from Cool Water be forecast at 3¢/th for the 2.0 MMDth per year of throughput attributed to Cool Water.

The Parties recommend that any recalculation of discounting during the BCAP test period, either as a result of the Commission adopting PG&E's proposal to rerun the discount calculation when implementing rates reflecting a change in the base revenue requirement, or as a result of the Commission adopting PG&E's proposal in the Capacity Brokering proceeding to rerun the discount calculation when the rates resulting from the Capacity Brokering proceeding are implemented, use the simplified discount adjustment model attached as Table 5.

In the event that subsequent actions of the Federal Energy Regulatory Commission (FERC) require unforeseen changes to the Commission's capacity brokering program that impact the expected amount of discounting by PG&E, then PG&E, DRA and TURN agree to meet and confer regarding any changes in the discount adjustment model set forth in Table 5. PG&E shall not unilaterally seek Commission modification of the simplified discount adjustment model during the BCAP test period without the consent of DRA and TURN. Such consent shall not be unreasonably withheld.

H. Cost Allocation

The Parties recommend that the Commission adopt the cost allocation methods presented by PG&E in its Updated Testimony, which are consistent with those presented by DRA.

I. Rate Design

The Parties recommend that the differential between residential Tier 1 and Tier 2 rates be reduced by the following formula.

PG&E's proposal should be used for this BCAP test period with three limitations. As proposed by DRA, the absolute size of the tier differential will not be closed by more than 50% in any one adjustment, and if the average residential rate is increasing by more than 10%, then the tier differential will remain unchanged. As proposed by TURN, the Tier 2 rate will not drop below 135% of the Tier I rate during the BCAP test period. If that limit is reached the tier differential will not be changed further, on a percentage basis, during the BCAP test period.

The Parties agree that beginning with the date rates are implemented in this proceeding, for those customers which have been authorized to switch from core to noncore after August 1, 1991, or which do switch during the test period, PG&E will track the difference between the revenue collected from these customers at their noncore rates and the revenue that would have been collected if they had continued to pay core rates, assuming the same usage. The allocation of this balance is to be determined in the next cost allocation proceeding.

The Parties recommend that the diversity adjustment for master metered rate schedules be recalculated, based on the rates adopted in this proceeding, using PG&E's model for calculating the 1993 PG&E General Rate Case diversity adjustment.

The Parties recommend that Southwest Gas Corporation's (SWG) rate design not be changed to all-volumetric in this proceeding. SWG agrees to file an application requesting Commission authorization before bypassing PG&E service. If the Commission approves SWG's application, for each month thereafter for the remainder of the BCAP test period SWG's total monthly PG&E demand charges will be reduced by the ratio of the estimate of that month's bypass developed in the authorization application to that month's SWG throughput adopted in this proceeding. The demand charge reduction will be recorded in a balancing account, to be recovered from all customers, based on cold year throughput, in PG&E's next cost allocation proceeding.

III.

GENERAL TERMS

The Parties agree that in this proceeding no Party will contest the issues resolved among the Parties by this Stipulation, by cross-examination of any Party witness on these issues, during briefing, or otherwise.

However, this shall not be construed to be an acceptance or endorsement of the principles, assumptions or methodologies underlying these recommendations. The Parties agree that the principles, assumptions and methodologies underlying the specific items addressed in this Stipulation are recommended for the purpose of this proceeding only, and are not to be deemed by the Commission or any other entity as precedent in any proceeding or litigation, except as necessary to implement the recommendations contained herein.

The Parties expressly reserve the right to advocate in other proceedings principles, assumptions, or methodologies different from those which may underlie or appear to be implied by this Stipulation, so long as this does not conflict with recommendations explicitly set forth in this Stipulation.

Unless the Commission accepts this Stipulation and the recommendations it contains in their entirety, without change or condition, the Parties agree that the Stipulation shall be null and void.

The Parties intend and agree that this Stipulation is subject to each and every condition set forth, including its acceptance by the Commission in its entirety and without change or condition.

The Parties agree to extend their best efforts to insure the adoption of this Stipulation.

The undersigned Parties agree to this Stipulation through their Counsel of Record in this proceeding.

Pacific Gas and Electric Company

By ________________ Date 3/19/92
MARK R. HUFFMAN

Division of Ratepayer Advocates

By ________________ Date 3-19-92
CAROL L. MATCHETT

Toward Utility Rate Normalization

By Michel P. Florio Date 3/19/92
MICHEL P. FLORIO

Southwest Gas Corporation

By John C. Walley Date 3/19/92
JOHN C. WALLEY

Western Mobilehome Association

By Richard L. Hamilton Date 3/19/92
RICHARD L. HAMILTON
MRH

ATTACHMENT A

Issues Not Resolved by

the Stipulation

Alternative Fuel Requirements for Noncore Status, and the Noncurtailment Penalty

1. PG&E's proposal to eliminate the alternate fuel capability requirement for noncore status;

2. PG&E's proposal to increase the curtailment noncompliance penalty from $1/th to $25/th;

3. The California Industrial Group, California League of Food Processors and California Manufacturers Association's (collectively CIG) proposal for a 24-hour grace period for compliance with curtailment requests;

4. Foster Farm's proposal to set the size requirement for noncore status as either the 100 Mcf per peak day or the 20,800 th per active month requirement.

OF Issues

1. PG&E's proposal to exclude the CPUC fee from the UEG-Cogeneration rate parity calculation;

2. The California Cogeneration Council's (CCC) proposal to exclude UEG igniter fuel from the UEG-Cogeneration rate parity calculation;

Revenue Requirement Issues

1. PG&E's proposal that PG&E's shareholders receive the final balance in the noncore PGA and DRA's proposal that noncore ratepayers receive this balance[1];

Storage Cost Allocation Issues

1. The California Gas Marketers Group (CGMG) and CIG's proposals to change the methodology for allocating storage costs. (The Stipulating Parties recommend in the Stipulation that the current methodology be used to allocate storage costs.);

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[1]This Stipulation does provide that if the Commission adopts DRA's proposal that ratepayers receive this balance, then DRA's proposal to include the balance as an offset to noncore rates should be adopted as well. This is discussed in Section II.F.

Other Cost Allocation Issues

1. DRA's proposal to record the Transwestern pipeline demand charges in an interest-bearing memorandum account.

2. PG&E's proposal to re-calculate the discount adjustment whenever the Commission implements in rates a change to PG&E's natural gas base revenue requirement[2];

3. CGMG's proposal to allocate the balance in the brokerage fee balancing account to only core-subscription customers. (The Stipulating Parties recommend in the Stipulation that the balance be allocated to all noncore customers.);

Wholesale Rate Design Issues

1. Palo Alto's proposal to revise the method of distributing the wholesale class revenue requirement;

2. Palo Alto's proposal that the Commission reconfirm wholesale customers' and PG&E's ability to

---

[2]This Stipulation does address the discount adjustment methodology to be used if the Commission adopts PG&E's proposal regarding the frequency of calculating the discount adjustment. This is discussed in Section II.G.

negotiate wholesale rate design;

3. Palo Alto's proposal to change the calculation of the wholesale core entitlement to the use of PG&E's storage facilities.

Retail Rate Design Issues

1. PG&E's proposals with respect to the Minimum Average Rate Limiter (MARL) for master-metered customers;

2. TURN's proposal to adopt a noncore "peaking" rate.

Table 1

PACIFIC GAS AND ELECTRIC COMPANY
FUELS PRICE FORECAST
(Dollars per Therm)

	Refiner's Avg. Acquisition Cost of Imported Crude*	No. 2 Distillate		No. 6 Residual		Propane	
		Whole.	Retail	Whole.	Retail	Whole.	Retail
1992:1	19.50	0.420	0.471	0.252	0.309	0.419	0.503
1992:2	19.10	0.411	0.460	0.247	0.302	0.341	0.409
1992:3	19.80	0.422	0.471	0.257	0.313	0.348	0.417
1992:4	20.40	0.432	0.481	0.265	0.323	0.426	0.511
1993:1	21.00	0.443	0.492	0.273	0.333	0.433	0.519
1993:2	20.80	0.439	0.487	0.270	0.330	0.358	0.429
1993:3	21.40	0.449	0.498	0.278	0.340	0.365	0.437
1993:4	22.00	0.460	0.510	0.287	0.350	0.443	0.532
1994:1	22.75	0.473	0.524	0.297	0.362	0.452	0.542
1994:2	22.60	0.471	0.521	0.295	0.360	0.378	0.454
1994:3	23.60	0.488	0.540	0.308	0.376	0.390	0.467
BCAP Yr. 1 (Aug. 1992 - Jul. 1993)		0.436	0.485	0.268	0.327	0.393	0.471
BCAP Yr. 2 (Aug. 1993 - Jul. 1994)		0.466	0.517	0.291	0.356	0.412	0.494

*Price in Dollars per Barrel

A.91-11-001

APPENDIX B
Page 19
Table 2

GAS DEMAND AND THROUGHPUT FORECASTS
REFLECTING SETTLEMENT ADJUSTMENTS
(MDTH)

BCAP PERIOD 1

Line No.	By Customer Class:	AVERAGE YEAR GAS DEMAND	AVERAGE YEAR CURTAIL MENTS	AVERAGE YEAR GAS THROUGHPUT	COLD YEAR GAS DEMAND	COLD YEAR CURTAIL MENTS	COLD YEAR GAS THROUGHPUT
1	Core Throughput						
2	Residential	208,541	0	208,541	242,403	0	242,403
3	Commercial	95,301	0	95,301	104,623	0	104,623
4	NGV	86	0	86	86	0	86
5	Interdepartmental	239	0	239	270	0	270
6	PG&E Start-up Fuel	1,298	0	1,298	1,298	0	1,298
7							
8	Total Core	305,465	0	305,465	348,680	0	348,680
9							
10	Noncore Throughput						
11	Industrial	159,466	0	159,466	159,466	0	159,466
12	SCE Cool Water	2,000	0	2,000	2,000	0	2,000
13	SteamHeat	1,099	0	1,099	1,212	0	1,212
14	Interdepartmental	117	0	117	132	0	132
15	Cogeneration	58,458	0	58,458	58,458	0	58,458
16	EOR	36,741	0	36,741	36,741	375	36,366
17	Wholesale	14,487	0	14,487	16,232	0	16,232
18							
19	Subtotal	272,368	0	272,368	274,241	375	273,866
20	UEG-PG&E	204,180	0	204,180	204,180	10,703	193,477
21							
22	TotalNoncore	476,548	0	476,548	478,421	11,078	467,343
23							
24	Other						
25	Gas Department Use	8,967	0	8,967	9,677	0	9,677
26	Lost & Unacct For (LUAF)	15,073	0	15,073	15,073	0	15,073
27							
28	TotalOther	24,040	0	24,040	24,750	0	24,750
29							
30	Total On-System	806,053	0	806,053	851,851	11,078	840,773

A.91-11-001

GAS DEMAND AND THROUGHPUT FORECASTS
REFLECTING SETTLEMENT ADJUSTMENTS
(MDTH)

BCP PERIOD 2

Line No.	By Customer Class:	AVERAGE YEAR GAS DEMAND	AVERAGE YEAR CURTAIL-MENTS	AVERAGE YEAR GAS THROUGHPUT	COLD YEAR GAS DEMAND	COLD YEAR CURTAIL-MENTS	COLD YEAR GAS THROUGHPUT
1	Core Throughput						
2	Residential	215,151	0	215,151	249,369	0	249,369
3	Commercial	99,076	0	99,076	108,751	0	108,751
4	NGV	229	0	229	229	0	229
5	Interdepartmental	243	0	243	273	0	273
6	PG&E Start-up Fuel	1,386	0	1,386	1,386	0	1,386
7						0	
8	Total Core	316,085	0	316,085	360,008	0	360,008
9							
10	Noncore Throughput						
11	Industrial	160,134	0	160,134	160,134	0	160,134
12	SCE Cool Water	2,000	0	2,000	2,000	0	2,000
13	SteamHeat	1,104	0	1,104	1,218	0	1,218
14	Interdepartmental	119	0	119	134	0	134
15	Cogeneration	65,611	0	65,611	65,611	0	65,611
16	EOR	38,198	0	38,198	38,198	0	38,198
17	Wholesale	14,808	0	14,808	16,624	0	16,624
18							
19	Subtotal	281,974	0	281,974	283,919	0	283,919
20	UEG-PG&E	198,029	0	198,029	198,029	0	198,029
21							
22	TotalNoncore	480,003	0	480,003	481,948	0	481,948
23							
24	Other						
25	Gas Department Use	8,703	0	8,703	9,444	0	9,444
26	Lost & Unacct For (LUAF)	15,073	0	15,073	15,073	0	15,073
27							
28	TotalOther	23,776	0	23,776	24,517	0	24,517
29							
30	Total On-System	819,864	0	819,864	866,473	0	866,473

Table 3

APPENDIX B
Page 20

Table 4

PACIFIC GAS AND ELECTRIC COMPANY
REVENUE REQUIREMENT SUMMARY
Forecast Period: 24 months beginning August 1, 1992

The items in *bold italics* are the changes to match the stipulation.
March 18, 1992

$(000)

Line No.		TOTAL PERIOD	YEAR 1	YEAR 2	Line No.
1	PROCUREMENT REVENUE REQUIREMENT				1
2					2
3	Forecasted Gas Supply Portfolio Costs	***$1,760,304***	***$873,781***	***$886,523***	3
4	PGA Subaccount Balances (See Table 5B)	($161,940)			4
5	Shrinkage Purchases (LUAF & GDU)	***$55,922***	***$28,365***	***$27,557***	5
6					6
7	Subtotal	$1,654,286			7
8	Franchise Fees and Uncollectible Accounts Expense	***$14,824***			8
9	Brokerage Fees	$13,274	$6,637	$6,637	9
10					10
11	Total Procurement Revenue Requirement	$1,682,384			11
12	Less: Procurement Revenues at Present Rates	***$2,153,917***			12
13					13
14	Change in Procurement Revenue Requirement	($471,533)			14
15					15
16					16
17	TRANSPORTATION REVENUE REQUIREMENT				17
18					18
19	Forecast Period Costs:				19
20	Base Revenue Amount (incl. F&U)	$2,265,264	$1,132,632	$1,132,632	20
21	EOR Credit	($20,798)	($10,067)	($10,731)	21
22	Interruptibility Credit	$0	$0	$0	22
23	Brokerage Fee Credit	($13,274)	($6,637)	($6,637)	23
24	Long-Term Contract Credit	$0	$0	$0	24
25	Pipeline Demand Charges	***$512,890***	***$255,413***	***$257,477***	25
26	Noncore Pipeline Demand Trueup	$3,373			26
27	Carrying Cost on Gas in Storage	$18,885	$9,452	$9,433	27
28	Noncore Storage Carrying Cost Trueup	($951)			28
29	Take-or-Pay Transition Costs	$13,776	$13,776	$0	29
30	El Paso TOP Deferred Account Balance	($5,506)			30
31	CFA Debt Service	$247	$176	$71	31
32	CFA Expense	$2,695	$1,571	$1,124	32
33	GEDA Expenses	$2,613	$2,613	$0	33
34	NGV Authorized Expenses	$5,720	$5,720	$0	34
35	El Paso Refund	($47,300)			35
36	CPUC Fee Expense	***$8,581***			36
37	LIRA	$402	$402	$0	37
38					38
39	Total Forecast Period Costs	$2,746,617			39
40	Transportation Account Balances (See Table 5B)	***$288,707***			40
41	Add'l Franchise Fees and Uncollectible Accounts Expense	***$7,140***			41
42					42
43	Total Transportation Revenue Requirement	$3,042,464			43
44	Less: Transportation Revenues at Present Rates	***$2,862,592***			44
45					45
46	Change in Transportation Revenue Requirement	$179,872			46
47					47
48	Total Change in Revenue Requirement	($291,661)			48

Note: This revenue requirement does not reflect DRA's proposal to return the $3.2 million overcollection in the Noncore Purchased Gas Account to customers.

Printed March 18, 1992 5P:N

TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
FORMULA FOR CALCULATING DISCOUNT

The following formula produces the annual forecast discount to the industrial class, given assumptions listed below.

Discount to industrial class = 42.0242 - [13.4092 / (.19202 + X)].

where:

The discount is in percent (and not less than zero);

X =forecast average standard industrial transportation rate ($/therm);

0.19202 is the core-subscription procurement rate (based on a WACOG of $.1825/th.);

So long as the interruptible rate is different from the standard average rate, the discount calculated above must be translated to a discount to just the interruptible class. This translation will be done following the methodology in Appendix B of PG&E's Prepared Testimony.

TABLE 6A (Stipulation)
PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
CORE BUNDLED RATES AND REVENUES

Line No	(A)	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 8/1/91: Adj Bill Det. MTH or CUST (B)	Rate $/TH (C)	Revenue $000 (D)	FORECAST REVENUES USING RATES FORECAST FOR AUG 92*: Adj Bill Det. MTH or CUST (E)	Rate $/TH (F)	Revenue $000 (G)	CHANGE IN RATES: $/TH (H)	% (I)	Line No
	RES. NON-LIRA									
1	Tier I (Baseline)	2,929,709	.50403	1,476,661	2,929,709	.49019	1,436,118	-.01384	-2.7 %	1
2	Tier II	953,008	.82421	785,479	953,008	.66309	631,929	-.16112	-19.5 %	2
3	Subtotal Non-LIRA	3,882,717 (1)	.58262	2,262,140	3,882,717	.53263	2,068,047	-.04999	-8.6 %	3
	RES. LIRA									
4	Tier I (Baseline)	255,265	.42590	108,740	255,265	.41455	105,821	-.01144	-2.7 %	4
5	Tier II	83,045	.69814	57,977	83,045	.56152	46,631	-.13662	-19.6 %	5
6	Subtotal LIRA	338,310	.49279	166,718	338,310	.45063	152,453	-.04217	-8.6 %	6
7	Pre-GS/GT Discnt Subtot.	4,221,027	.57542	2,428,858	4,221,027	.52606	2,220,499	-.04936	-8.6 %	7
8	GS GT Discount (1)			-12,390			-12,273			8
9	Total Residential	4,221,027	.57248	2,416,468	4,221,027	.52315	2,208,226	-.04933	-8.6 %	9
	SCHEDULE G-NR1 (1)									
10	Customer Charge	196,284	12.06	56,813	196,284	13.63	64,201	1.57	13.0 %	10
11	Summer Vol. Rate (1)	734,540	.47909	351,911	734,540	.42792	314,325	-.05117	-10.7 %	11
12	Winter Vol. Rate (1)	845,230	.64677	546,669	845,230	.57769	488,283	-.06908	-10.7 %	12
13	Total G-NR1	1,579,770	.60477	955,393	1,579,770	.54869	866,809	-.05607	-9.3 %	13
	SCHEDULE G-NR2 (1)									
14	Customer Charge	514.8	139.40	1,722	514.8	153.04	1,891	13.64	9.8 %	14
15	Summer Vol. Rate (1)	171,960	.42525	73,126	171,960	.37165	63,910	-.05360	-12.6 %	15
16	Winter Vol. Rate (1)	186,120	.57409	106,850	186,120	.50173	93,383	-.07236	-12.6 %	16
17	Total G-NR2	358,080	.50742	181,698	358,080	.44455	159,183	-.06288	-12.4 %	17
18	Total Commercial	1,937,850	.58678	1,137,091	1,937,850	.52945	1,025,992	-.05733	-9.8 %	18
19	Total Bundled Core	6,158,877	.57698	3,553,558	6,158,877	.52513	3,234,218	-.05185	-9.0 %	19

EXPERIMENTAL BUNDLED RATES AND REVENUES

Line No	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	Line No
	SCHEDULE G-NGV1									
20	Customer Charge	10	11.99	3	10	13.63	3	1.64	13.7 %	20
21	Volumetric Rate	1,580	.51099	807	1,580	.42357	669	-.08742	-17.1 %	21
22	Total G-NGV1	1,580	.51272	810	1,580	.42553	672	-.08719	-17.0 %	22
	SCHEDULE G-NGV2									
23	Customer Charge	175	11.99	50	175	13.63	57	1.64	13.7 %	23
24	Volumetric Rate	1,570	.61405	964	1,570	.53357	838	-.08048	-13.1 %	24
25	Total G-NGV2	1,570	.64614	1,014	1,570	.57002	895	-.07611	-11.8 %	25
25	TOTAL G-NGV	3,150	.57922	1,825	3,150	.49735	1,567	-.08187	-14.1 %	25

* [illegible]

** [illegible]

*** [illegible]

TABLE 6B (Stipulation)
PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
CORE TRANSPORT RATES AND REVENUES

Line No	(A)		FORECAST REVENUES USING PRESENT RATES EFFECTIVE 8/1/91			FORECAST REVENUES USING RATES FORECAST FOR AUG 92*			CHANGE IN RATES		Line No
			Adj Bill Det. MTH or CUST (B)	Rate $/TH (C)	Revenue $000 (D)	Adj Bill Det. MTH or CUST (E)	Rate $/TH (F)	Revenue $000 (G)	$/TH (H)	% (I)	
	RES. NON-LIRA										
1	Tier I (Baseline)		5,882	.26391	1,552	5,882	.32400	1,906	.06009	22.8 %	1
2	Tier II		1,500	.59409	876	1,500	.49690	745	-.09719	-14.8 %	2
3	Subtotal Non-LIRA		7,382	.32895	2,428	7,382	.35912	2,651	.03017	9.2 %	3
	RES. LIRA										
4	Tier I (Baseline)		513	.18587	95	513	.24836	127	.06249	33.6 %	4
5	Tier II		131	.45802	60	131	.39533	52	-.06269	-13.7 %	5
6	Subtotal LIRA		643	.24116	155	643	.27822	179	.03706	15.4 %	6
7	Total Residential		8,025	.32152	2,583	8,025	.35264	2,830	.03072	9.5 %	7
	SCHEDULE G-NR1										
8	Customer Charge		4,171	12.06	1,207	4,171	13.63	1,364	1.57	13.0 %	8
9	Summer Vol. Rate	(1)	17,550	.23897	4,194	17,550	.26173	4,593	.02276	9.5 %	9
10	Winter Vol. Rate	(1)	16,020	.40665	6,515	16,020	.41150	6,592	.00485	1.2 %	10
11	Total G-NR1		33,570	.35495	11,916	33,570	.37384	12,550	.01889	5.3 %	11
	SCHEDULE G-NR3										
12	Customer Charge		6	139.40	19	5.8	153.04	21	13.64	9.8 %	12
13	Summer Rate	(1)	1,870	.19301	361	1,870	.20546	384	.01245	6.5 %	13
14	Winter Rate	(1)	2,140	.34185	732	2,140	.33554	718	-.00631	-1.8 %	14
15	Total G-NR3		4,010	.27725	1,112	4,010	.28016	1,123	.00291	1.1 %	15
16	Commercial Transport		37,580	.34666	13,027	37,580	.36385	13,673	.01719	5.0 %	16
17	Total Core Transport		45,605	.34231	15,611	45,605	.36187	16,503	.01957	5.7 %	17
18	TOTAL CORE		6,204,482		3,569,169	6,204,482		3,250,722			18

* Excludes approved 1992 Attrition changes to base revenues which became effective 1/1/92. Thus, all rate tables presented to date by PG&E in the 1992 BCAP are on a consistent basis.

TABLE 6C (Stipulation)
PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
INDUSTRIAL, UEG, & COGENERATION TRANSPORT RATES AND REVENUES

Line No	(A)	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 8/1/91			FORECAST REVENUES USING RATES FORECAST FOR AUG 92*			CHANGE IN RATES		Line No
		Adj Bill Det. MTH or CUST (B)	Rate $/TH (C)	Revenue $000 (D)	Adj Bill Det. MTH or CUST (E)	Rate $/TH (F)	Revenue $000 (G)	$/TH (H)	% (I)	
	INDUSTRIAL (6)									
	SCHEDULE G-FT									
1	Customer Charge	570.34	426.63	5,840	570.34	562.65	7,702	136.02	31.9 %	1
2	Summer Volumetric	1,161,850	.11509	133,717	1,161,850	.11335	131,697	-.00174	-1.5 %	2
3	Winter Volumetric	865,270	.13173	113,982	865,270	.12752	110,343	-.00421	-3.2 %	3
4	Avg. Std. Rate (adj. vol.)	2,027,120	.12507	253,539	2,027,120	.12320	249,742	-.00187	-1.5 %	4
5	Avg. Rate (unadj. vol.)	2,027,120	.12507	253,539	2,027,120	.12320	249,742	-.00187	-1.5 %	5
	SCHEDULE G-IT									
6	Customer Charge	338.62	426.63	3,467	338.62	562.65	4,573	136.02	31.9 %	6
7	Summer Volumetric	708,701	.09002	63,797	791,266	.07413	58,656	-.01589	-17.7 %	7
8	Winter Volumetric	373,473	.10666	39,835	417,119	.08830	36,833	-.01836	-17.2 %	8
9	Avg. Std. Rate (adj. vol.)	1,082,174	.09897	107,099	1,208,385	.08281	100,062	-.01616	-16.3 %	9
10	Avg. Rate (unadj. vol.)	1,233,250	.08684	107,099	1,233,250	.08114	100,062	-.00571	-6.6 %	10
	INDUSTRIAL AVERAGES									
11	Customer Charge	908.96	426.63	9,307	908.96	562.65	12,274	136.02	31.9 %	11
12	Summer Volumetric	1,870,551	.10559	197,515	1,953,116	.09746	190,353	-.00813	-7.7 %	12
13	Winter Volumetric	1,238,743	.12417	153,817	1,282,389	.11477	147,176	-.00940	-7.6 %	13
14	Avg. Std. Rate (adj. vol.)	3,109,294	.11599	360,634	3,235,505	.10811	349,803	-.00787	-6.8 %	14
15	Avg. Rate (unadj. vol.)	3,260,370	.11061	360,630	3,260,370	.10729	349,803	-.00332	-3.0 %	15
	UEG (7)									
16	Customer Charge	1	77,562	1,861	1	87,611	2,103	10,049	13.0 %	16
17	Demand Charge			205,749			279,072	73,323	35.6 %	17
18	Tier I Volumetric	541,162	.04352	23,551	744,087	.03543	26,363	-.00809	-18.6 %	18
19	Tier II Volumetric	3,480,928	.01295	45,078	3,278,003	.00692	22,671	-.00603	-46.6 %	19
20	Avg. Rate	4,022,090	.06868	276,240	4,022,090	.08210	330,209	.01342	19.5 %	20
	COGEN (8)									
	G-COG Firm									
21	Summer Volumetric	333,939	.09396	31,377	333,939	.09263	30,932	-.00133	-1.4 %	21
22	Winter Volumetric	226,949	.10771	24,445	226,949	.10641	24,150	-.00130	-1.2 %	22
23	Avg. Rate	560,888	.09952	55,822	560,888	.09820	55,082	-.00132	-1.3 %	23
	G-COG Interruptible									
24	Summer Volumetric	149,524	.06889	10,301	149,524	.05340	7,985	-.01549	-22.5 %	24
25	Winter Volumetric	121,389	.08264	10,032	121,389	.06719	8,156	-.01545	-18.7 %	25
26	Avg. Rate	270,913	.07505	20,332	270,913	.05958	16,142	-.01547	-20.6 %	26
	G-COG Averages									
27	Summer Volumetric	483,463	.08621	41,678	483,463	.08050	38,917	-.00571	-6.6 %	27
28	Winter Volumetric	348,338	.09897	34,476	348,338	.09274	32,306	-.00623	-6.3 %	28
29	Avg. Rate	831,801	.09155	76,154	831,801	.08563	71,223	-.00593	-6.5 %	29
30	G-PO3 Firm	277,888	.08548	23,753	277,888	.09822	27,295	.01275	14.9 %	30
31	G-PO3 Interruptible	62,987	.04905	3,090	62,987	.05987	3,771	.01082	22.1 %	31
32	G-PO3 Averages	340,875	.07875	26,843	340,875	.09114	31,066	.01239	15.7 %	32
33	Total COGEN	1,172,676	.08783	102,997	1,172,676	.08723	102,290	-.00060	-0.7 %	33
34	GC2 Revenue	68,004		5,768	68,004		5,724			34
35	COGEN Including GC2	1,240,680	.08767	108,765	1,240,680	.08706	108,013	-.00061	-0.7 %	35

3/18/92

TABLE 6D (Stipulation)
PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
WHOLESALE AND SUMMARY OF NONCORE TRANSPORT RATES AND REVENUES

Line No.	(A)	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 8/1/91			FORECAST REVENUES USING RATES FORECAST FOR AUG 92*			CHANGE IN RATES		Line No
		Adj Bill Det	Rate	Revenue	Adj Bill Det	Rate	Revenue			
		MTH or CUST (B)	$/TH (C)	$000 (D)	MTH or CUST (E)	$/TH (F)	$000 (G)	$/TH (H)	% (I)	
	WHOLESALE									
1	Demand Charge (1)			23,688			26,453	2,764	11.7 %	1
2	Volumetric Rate	292,940	.00446	1,307	292,940	.00529	1,549	.00083	18.6 %	2
3	Avg. Rate	292,940	.08532	24,995	292,940	.09559	28,002	.01026	12.0 %	3
	TOTAL NC TRANSPORT									
4	Adjusted volumes	8,665,004	.08894	770,638	8,791,215	.09282	816,027	.00389	4.4 %	4
5	Unadjusted volumes	8,816,080	.08741	770,638	8,816,080	.09256	816,027	.00515	5.9 %	5
	CORE SUBSCRIPTION									
6	Industrial & COGEN	722,780	.19404	140,245	722,780	.18905	136,639	-.00499	-2.6 %	6
7	UEG	2,614,370	.19404	507,281	2,614,370	.18905	494,239	-.00499	-2.6 %	7
8	Wholesale	138,470	.19367	26,818	138,470	.18870	26,129	-.00498	-2.6 %	8
9	Total NC Procurement	3,475,620	.19402	674,344	3,475,620	.18903	657,007	-.00499	-2.6 %	9
	REVENUE SUMMARY									
	Core									
10	Transport			15,611			16,503	892	5.7 %	10
11	Bundled (1)			3,555,383			3,234,742	-320,641	-9.0 %	11
12	Total Core			3,570,994			3,251,245	-319,748	-9.0 %	12
	Noncore									
13	Transport			770,638			816,027	45,389	5.9 %	13
14	EOR-CPUC Revenue			570			570			14
15	Procurement			674,344			657,007	-17,337	-2.6 %	15
16	Gas cost adjustment (1)						0			16
17	Total Noncore			1,445,552			1,473,604	28,052	1.9 %	17
18	Total			5,016,546			4,724,850	-291,696	-5.8 %	18

* [illegible]

PACIFIC GAS AND ELECTRIC COMPANY
NOTES TO TABLES 6A - 6D

1. Residential volumes are adjusted for G-10 sales.

2. "GS,GT Discount" refers to the discounts master-metered customers receive for providing submetering service to tenants.

3. Schedule G-NR1 is applicable to P1 and P2A customers with use of fewer than 20,800 therms per active month.

4. Schedule G-NR2 is applicable to P1 and P2A customers with use of at least 20,800 therms per active month. Schedule G-NR2 includes UEG igniter fuel and core interdepartmental. Schedule G-NR3 is available to customers eligible for Schedule G-NR2 who desire transportation-only service from PG&E.

5. For non-residential schedules, the summer season is from April 1 to October 31 and the winter season is from November 1 to March 31.

6. The Industrial class applies to P2B, P3A (otherwise-applicable schedule for most cogenerators), P3B, P4, and P5 (other than electric generating plants) customers. This class includes noncore interdepartmental, steam heat, and SCE Cool Water throughput. Schedule G-FT is firm transportation service (Service Level 2). Schedule G-IT is interruptible transportation service (Service Levels 3-5).

7. The UEG class applies to PG&E noncore power plant use.

8. Schedule G-PO3 applies to cogenerators on Interim Standard Offer 4, Energy Payment Option 3. The rates adjust monthly based on actual deliveries and revenues from PG&E's steam-electric generating plants recorded two months prior. Schedule G-COG applies to all other cogenerators. The rates for Schedule G-COG are based on the forecasted average transportation rate to PG&E's steam-electric generating plants.

9. Column (G) reflects the rate design from Resolution No. G-2961. Column (D) is based on the 8/1/91 rate design and includes the core demand charge and noncore volumetric revenue.

10. NGV bundled revenue is included in Column (D). NGV procurement revenue is included in Column (G).

11. Represents the forecasted undercollection for Core Subscription at the end of the BCAP test period.

TABLE 6E (Stipulation)
PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
PROCUREMENT RATE CALCULATION TABLE

Period: Aug 92 to July 94

LINE No.		CORE	CORE-SUB	WHSL CS	TOTAL
1	SALES (Mth)	6,169,880	3,337,150	138,470	9,645,500
2	WACOG ($/therm)	.18250	.18250	.18250	.18250
3	SUBTOTAL REVENUE (000's)	$1,126,003	$609,030	$25,271	$1,760,304
4	CORE PGA BALANCE (000'S)	($145,534)			($145,534)
5	CORE-SUBSCRIPTION PGA BALANCE		($15,752)	($654)	($16,406)
6	SUBTOTAL REVENUE (000's)	$980,469	$593,277	$24,617	$1,598,364
7	F&U RATE */	.89900%	.89900%	.70900%	.89607%
8	F&U	8,814	5,334	175	14,323
9	SUBTOTAL REVENUE (000's)	$989,284	$598,611	$24,792	$1,612,666
10	RATE BEFORE BROKERAGE FEES AND SHRINKAGE($/th) [a]	.16034	.17938	.17904	.16720
11	BROKERAGE FEES INCL F&U (000's)		$12,745	$529	$13,274
12	BROKERAGE FEE RATE ($/th) [b]		.00382	.00382	.00138
13	SHRINKAGE REVENUE (000's)	$35,771	$19,348	$803	$55,922
14	F&U ON SHRINKAGE REV (000's)	$322	$174	$6	$501
15	SHRINKAGE REV INCL F&U (000's)	$36,093	$19,522	$809	$56,423
16	SHRINKAGE RATE ($/th) [c]	.00585	.00585	.00584	.00585
	TOTAL PROCUREMENT REV (000's)	1,025,376	630,878	26,129	1,682,363
17	FINAL PROCUREMENT RATE [a+b+c]	.16619	.18905	.18870	.17442

*/ WHSL PAYS FRANCHISE FEES ONLY.

(END OF APPENDIX B)

PACIFIC GAS AND ELECTRIC COMPANY
FUELS PRICE FORECAST
(Dollars per Therm)

	Refiner's Avg. Acquisition Cost of Imported Crude*	No. 2 Distillate Whole.	No. 2 Distillate Retail	No. 6 Residual Whole.	No. 6 Residual Retail	Propane Whole.	Propane Retail
1992:1	19.50	0.420	0.471	0.252	0.309	0.419	0.503
1992:2	19.10	0.411	0.460	0.247	0.302	0.341	0.409
1992:3	19.80	0.422	0.471	0.257	0.313	0.348	0.417
1992:4	20.40	0.432	0.481	0.265	0.323	0.426	0.511
1993:1	21.00	0.443	0.492	0.273	0.333	0.433	0.519
1993:2	20.80	0.439	0.487	0.270	0.330	0.358	0.429
1993:3	21.40	0.449	0.498	0.278	0.340	0.365	0.437
1993:4	22.00	0.460	0.510	0.287	0.350	0.443	0.532
1994:1	22.75	0.473	0.524	0.297	0.362	0.452	0.542
1994:2	22.60	0.471	0.521	0.295	0.360	0.378	0.454
1994:3	23.60	0.488	0.540	0.308	0.376	0.390	0.467
BCAP Yr. 1 (Aug. 1992 - Jul. 1993)		0.436	0.485	0.268	0.327	0.393	0.471
BCAP Yr. 2 (Aug. 1993 - Jul. 1994)		0.466	0.517	0.291	0.356	0.412	0.494

*Price in Dollars per Barrel

(END OF APPENDIX C)

APPENDIX D
Page 1

ADOPTED GAS DEMAND AND THROUGHPUT
AVERAGE YEAR
(MDTH)

BCAP PERIOD 1
August 1, 1992 to July 31, 1993

Line No.	By Customer Class	Gas Demand	Curtailments	Gas Throughput
1	Core Throughput			
2	Residential	208,541	0	208,541
3	Commercial	95,301	0	95,301
4	NGV	86	0	86
5	Interdepartmental	239	0	239
6	PG&E Start-up Fuel	1,298	0	1,298
7	Total Core	305,465	0	305,465
8				
9	Noncore Throughput			
10	Industrial	164,663	0	164,663
11	SCE Cool Water	2,000	0	2,000
12	Steam Heat	1,099	0	1,099
13	Interdepartmental	117	0	117
14	Cogeneration	62,160	0	62,160
15	EOR	36,738	0	36,738
16	Wholesale	14,487	0	14,487
17	Subtotal	281,264	0	281,264
18	UEG-PG&E	204,180	0	204,180
19	Total Noncore	485,444	0	485,444
20				
21	Other			
22	Gas Department Use	8,967	0	8,967
23	Lost & Unacct	15,072	0	15,072
24	Total Other	24,039	0	24,039
25				
26	Total On-System	814,948	0	814,948

APPENDIX D
Page 2

ADOPTED GAS DEMAND AND THROUGHPUT
COLD YEAR
(MDTH)

BCAP PERIOD 1
August 1, 1992 to July 31, 1993

Line No.	By Customer Class	Gas Demand	Curtail-ments	Gas Throughput
1	Core Throughput			
2	Residential	242,403	0	242,403
3	Commercial	104,623	0	104,623
4	NGV	86	0	86
5	Interdepartmental	270	0	270
6	PG&E Start-up Fuel	1,298	0	1,298
7	Total Core	348,680	0	348,680
8				
9	Noncore Throughput			
10	Industrial	164,666	0	164,666
11	SCE Cool Water	2,000	0	2,000
12	Steam Heat	1,212	0	1,212
13	Interdepartmental	132	0	132
14	Cogeneration	62,158	0	62,158
15	EOR	36,741	375	36,366
16	Wholesale	16,232	0	16,232
17	Subtotal	283,141	375	282,766
18	UEG-PG&E	204,180	10,703	193,477
19	Total Noncore	487,321	11,078	476,243
20				
21	Other			
22	Gas Department Use	9,677	0	9,677
23	Lost & Unacct	15,073	0	15,073
24	Total Other	24,750	0	24,750
25				
26	Total On-System	860,751	11,078	849,673

APPENDIX D
Page 3

ADOPTED GAS DEMAND AND THROUGHPUT
AVERAGE YEAR
(MDTH)

BCAP PERIOD 2
August 1, 1993 to July 31, 1994

Line No.	By Customer Class	Gas Demand	Curtail-ments	Gas Throughput
1	Core Throughput			
2	Residential	215,151	0	215,151
3	Commercial	99,076	0	99,076
4	NGV	229	0	229
5	Interdepartmental	240	0	240
6	PG&E Start-up Fuel	1,386	0	1,386
7	Total Core	316,082	0	316,082
8				
9	Noncore Throughput			
10	Industrial	165,332	0	165,332
11	SCE Cool Water	2,000	0	2,000
12	Steam Heat	1,104	0	1,104
13	Interdepartmental	119	0	119
14	Cogeneration	69,313	0	69,313
15	EOR	38,194	0	38,194
16	Wholesale	14,808	0	14,808
17	Subtotal	290,870	0	290,870
18	UEG-PG&E	198,029	0	198,029
19	Total Noncore	488,899	0	488,899
20				
21	Other			
22	Gas Department Use	8,703	0	8,703
23	Lost & Unacct	15,072	0	15,072
24	Total Other	23,775	0	23,775
25				
26	Total On-System	828,756	0	828,756

APPENDIX D
Page 4

ADOPTED GAS DEMAND AND THROUGHPUT
COLD YEAR
(MDTH)

BCAP PERIOD 2
August 1, 1993 to July 31, 1994

Line No.	By Customer Class	Gas Demand	Curtailments	Gas Throughput
1	Core Throughput			
2	Residential	249,367	0	249,367
3	Commercial	108,751	0	108,751
4	NGV	229	0	229
5	Interdepartmental	273	0	273
6	PG&E Start-up Fuel	1,386	0	1,386
7	Total Core	360,006	0	360,006
8				
9	Noncore Throughput			
10	Industrial	165,334	0	165,334
11	SCE Cool Water	2,000	0	2,000
12	Steam Heat	1,218	0	1,218
13	Interdepartmental	134	0	134
14	Cogeneration	69,311	0	69,311
15	EOR	38,198	0	38,198
16	Wholesale	16,624	0	16,624
17	Subtotal	292,819	0	292,819
18	UEG-PG&E	198,029	0	198,029
19	Total Noncore	490,848	0	490,848
20				
21	Other			
22	Gas Department Use	9,444	0	9,444
23	Lost & Unacct	15,073	0	15,073
24	Total Other	24,517	0	24,517
25				
26	Total On-System	875,371	0	875,371

APPENDIX D
Page 5

ADOPTED UEG MONTHLY THROUGHPUT
AVERAGE YEAR
(MDTH)

Line No.	Month	1992/93 SL2-CS	1992/93 SL4/S-IT	1992/93 Subtotal	1993/94 SL2-CS	1993/94 SL4/S-IT	Subtotal
1	Aug	10,380	5,589	15,969	15,408	8,297	23,705
2	Sep	11,670	6,284	17,954	13,278	7,150	20,428
3	Oct	13,808	7,435	21,243	8,412	4,529	12,941
4	Nov	16,064	8,650	24,714	9,571	5,153	14,724
5	Dec	12,405	6,680	19,085	8,154	4,391	12,545
6	Jan	8,226	4,430	12,656	8,938	4,812	13,750
7	Feb	7,227	3,891	11,118	8,731	4,701	13,432
8	Mar	8,128	4,376	12,504	9,350	5,034	14,384
9	Apr	12,596	6,783	19,379	12,975	6,987	19,962
10	May	9,094	4,897	13,991	9,519	5,126	14,645
11	Jun	9,871	5,315	15,186	10,462	5,633	16,095
12	Jul	13,248	7,133	20,381	13,922	7,496	21,418
	Total	132,717	71,463	204,180	128,719	69,310	198,029

(END OF APPENDIX D)

APPENDIX E

PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
PROCUREMENT RATE CALCULATION TABLE

Period: Aug. 92 to Jul. 94

LINE No.		CORE	CORE-SUB	WHSL CS	TOTAL	LINE No.
1	SALES (Mth)	6,169,880	3,337,150	138,470	9,645,500	1
2	WACOG ($/therm)	.18250	.18250	.18250	.18250	2
3	SUBTOTAL REVENUE (000's)	$1,126,003	$609,030	$25,271	$1,760,304	3
4	CORE PGA BALANCE (000'S)	($135,861)			($135,861)	4
5	CORE-SUBSCRIPTION PGA BALANCE		($7,984)	($331)	($8,315)	5
6	SUBTOTAL REVENUE (000's)	$990,142	$601,046	$24,940	$1,616,128	6
7	F&U RATE */	.89900%	.89900%	.70900%	.89607%	7
8	F&U	8,901	5,403	177	14,482	8
9	SUBTOTAL REVENUE (000's)	$999,043	$606,450	$25,116	$1,630,609	9
10	RATE BEFORE BROKERAGE FEES AND SHRINKAGE($/th) (a)	.16192	.18173	.18138	.16905	10
11	BROKERAGE FEES INCL F&U (000's)		$12,745	$529	$13,274	11
12	BROKERAGE FEE RATE ($/th) (b)		.00382	.00382	.00138	12
13	SHRINKAGE REVENUE (000's)	$35,771	$19,348	$803	$55,922	13
14	F&U ON SHRINKAGE REV (000's)	$322	$174	$6	$501	14
15	SHRINKAGE REV INCL F&U (000's)	$36,093	$19,522	$809	$56,423	15
16	SHRINKAGE RATE ($/th) (c)	.00585	.00585	.00584	.00585	16
	TOTAL PROCUREMENT REV (000's)	1,035,136	638,717	26,454	1,700,307	
17	FINAL PROCUREMENT RATE (a+b+c)	.16777	.19140	.19104	.17628	17

*/ WHSL PAYS FRANCHISE FEES ONLY.

(END OF APPENDIX E)

APPENDIX F
Page 1

ADOPTED REVENUE REQUIREMENT
PACIFIC GAS AND ELECTRIC COMPANY

PROCUREMENT REVENUE REQUIREMENT	TOTAL PERIOD	First Year	Second Year
Forecast Period Costs:			
Forecasted Gas Supply Portfolio Costs	$1,760,304	$880,152	$880,152
PGA Subaccount Balances	($144,176)	($72,088)	($72,088)
Shrinkage Purchases (LUAF & GDU)	$55,922	$27,961	$27,961
Shrinkage Account Balances	$0	$0	$0
	============	=========	=========
Subtotal	$1,672,050	$836,025	$836,025
Franchise Fees & Uncoll. Accounts Expen.	$14,983	$7,491	$7,491
Brokerage Fees	$13,274	$6,637	$6,637
Total Procurement Revenue Requirement	$1,700,307	$850,153	$850,153
Less: Procurement Rev at Present Rates	$2,148,911	$1,074,456	$1,074,456
	============	=========	=========
Change in Procurement Revenue Requirement	($448,604)	($224,302)	($224,302)

TRANSPORTATION REVENUE REQUIREMENT	TOTAL PERIOD	First Year	Second Year
Forecast Period Costs:			
Base Revenue Amount	$2,431,404	$1,215,702	$1,215,702
EOR Credit	($20,798)	($10,399)	($10,399)
Interutility Credit	$0	$0	$0
Brokerage Fee Credit	($13,274)	($6,637)	($6,637)
Long-Term Contract Credit	$0	$0	$0
Pipeline Demand Charges	$475,730	$237,865	$237,865
Noncore Pipeline Demand Trueup	$6,196	$3,098	$3,098
Carrying Cost on Gas in Storage	$12,813	$6,406	$6,407
Noncore Storage Carrying Cost Trueup	($1,238)	($619)	($619)
Take-or-Pay Transition Costs	$19,600	$9,800	$9,800
El Paso TOP Deferred Account Balance	($5,895)	($2,948)	($2,947)
CFA Debt Service	$247	$124	$123
CFA Expense	$2,695	$1,348	$1,347
GEDA Expenses	$2,613	$1,307	$1,306
NGV expenses	$5,720	$2,860	$2,860
El Paso Refund	($49,006)	($24,503)	($24,503)
CPUC Fee Expense	$8,775	$4,388	$4,387
LIRA	$402	$201	$201
CEE Expense	$1,796	$898	$898
Total Forecast Period Costs	$2,877,780	$1,438,892	$1,438,888
Transportation Balancing Accounts	$195,870		
Add'l Franchise Fees & Uncoll. Accounts Expen.	$5,992		
	============		
Total Transportation Revenue Requirement	$3,079,641		
Less: Transportation Rev at Present Rates	$3,068,046		
	============		
Change in Transportation Revenue Requirement	$11,595		
	============		
Total Change in Revenue Requirement	($437,016)		
	============		
Total Revenue Requirement	$4,779,940		

APPENDIX F
Page 2

PROCUREMENT BALANCING ACCOUNTS	TOTAL PERIOD
Core Subaccount Balance	($135,861)
Core-Subscription Subaccount Balance	($8,463)
Balancing Charge Subaccount Balance	$148
Core Excess Supply Subaccount Balance	$0
Procurement Take-or-Pay Subaccount Balance	$0
	============
Sum of PGA Suneccount Balance	($144,176)
PROCUREMENT MEMO ACCOUNTS	
Noncore PGA Refund	$5,200
TRANSPORTATION BALANCING ACCOUNTS	
Core Fixed Cost Acct. Bal.	$155,015
CFCA Shrinkage Subaccount Balance	($7,369)
Noncore Fixed Cost Acct. Bal..	$32,043
Noncore Fixed Cost Account Balance	($6,689)
Noncore Transition Cost Account Balance	($6,347)
Enhanced Oil Recovery Account Balance	$1,423
Interutility Balancing Account Balance	($57)
GEDA Balancing Account Balance	$31,251
CFA Expense Account Balance	$2,183
CFA Debt Service Account Balance	$4,622
Low Income Rate Assistance Account Balance	($9,732)
Natural Gas Vehicle Account Balance	$5,655
Firm Surcharge/Interruptible Credit Account Balance	($11,659)
Noncore Defferred Subaccount Balance	$0
Curtailment Charge Tracking Account Balance	($116)
Brokerage Fee Account Balance	$5,647
	============
Total Transportation Balances	$195,870

(END OF APPENDIX F)

APPENDIX G

EXPERIMENTAL CORE GAS TRANSPORT SERVICE
SCHEDULE G-CT RULES

Bundled core service customers electing core transport-only service under PG&E's rate Schedule G-CT after August 1, 1992 will receive the core purchased gas adjustment (PGA) credit for the biennnial cost allocation proceeding (BCAP) period covered by D.92-10-051. Schedule G-CT customers electing bundled core service after August 1, 1992 will not receive the PGA credit for this BCAP period.

These rules will remain in place until the currently scheduled end of the experimental core-transport program (August 1, 1994), or the beginning of PG&E's next BCAP period after D.92-10-051, whichever comes first.

(END OF APPENDIX G)

APPENDIX H

Page 1

ADOPTED RATES AND REVENUES
PACIFIC GAS AND ELECTRIC COMPANY
CORE BUNDLED RATES AND REVENUES

		FORECAST REVENUES USING PRESENT RATES EFFECTIVE 1/1/92			FORECAST REVENUES USING RATES FORECAST FOR AUG 92			CHANGE IN RATES	
		Adj.Bill.Det.	Rate	Revenue	Adj.Bill.Det.	Rate	Revenue		
Line		MTH or CUS	$/TH	$000	TH or CUS	$/TH	$000	$/TH	%
No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	RES. NON-LIRA								
1	Tier I (Baseline)	2,929,709	.52538	1,539,210	2,929,709	.49589	1,452,815	-.02949	-5.6 %
2	Tier II	953,008	.84556	805,826	953,008	.66920	637,754	-.17636	-20.9 %
3	Subtotal Non-LIRA	3,882,717	.60397	2,345,036	3,882,717	.53843	2,090,569	-.06554	-10.9 %
	RES. LIRA								
4	Tier I (Baseline)	255,265	.44419	113,386	255,265	.41985	107,174	-.02434	-5.5 %
5	Tier II	83,045	.71634	59,489	83,045	.56684	47,074	-.14950	-20.9 %
6	Subtotal LIRA	338,310	.51099	172,875	338,310	.45594	154,248	-.05506	-10.8 %
7	Pre-GS/GT Discnt Subtot.	4,221,027	.59652	2,517,911	4,221,027	.53182	2,244,816	-.06470	-10.8 %
8	GS,GT Discount			-12,390			-16,474		
9	Total Residential	4,221,027	.59358	2,505,521	4,221,027	.52791	2,228,343	-.06567	-11.1 %
	SCHEDULE G-NR1								
[illegible]	Customer Charge	196,284	13.14	61,900	196,284	14.60	68,777	1.46	11.1 %
11	Summer Vol. Rate	734,540	.50070	367,784	734,540	.42962	315,574	-.07108	-14.2 %
12	Winter Vol. Rate	845,230	.67596	571,342	845,230	.57999	490,224	-.09597	-14.2 %
13	Total G-NR1	1,579,770	.63365	1,001,026	1,579,770	.55361	874,575	-.08004	-12.6 %
	SCHEDULE G-NR2								
14	Customer Charge	514.8	151.46	1,871	514.8	163.94	2,026	12.48	8.2 %
15	Summer Vol. Rate	171,960	.44237	76,070	171,960	.37461	64,418	-.06776	-15.3 %
16	Winter Vol. Rate	186,120	.59720	111,151	186,120	.50572	94,125	-.09148	-15.3 %
17	Total G-NR2	358,080	.52807	189,092	358,080	.44841	160,568	-.07966	-15.1 %
18	Total Commercial	1,937,850	.61414	1,190,118	1,937,850	.53417	1,035,143	-.07997	-13.0 %
19	Total Bundled Core	6,158,877	.60005	3,695,639	6,158,877	.52988	3,263,486	-.07017	-11.7 %

EXPERIMENTAL BUNDLED RATES AND REVENUES

	SCHEDULE G-NGV1								
20	Customer Charge	10	12.43	3	10	14.60	3	2.17	17.4 %
21	Volumetric Rate	1,580	.53248	841	1,580	.42704	675	-.10544	-19.8 %
22	Total G-NGV1	1,580	.53421	844	1,580	.42915	678	-.10506	-19.7 %
	SCHEDULE G-NGV2								
[illegible]	Customer Charge	175	12.43	50	175	14.60	61	2.17	17.4 %
24	Volumetric Rate	1,570	.63555	998	1,570	.53105	834	-.10450	-16.4 %
25	Total G-NGV2	1,570	.66763	1,048	1,570	.57010	895	-.09752	-14.6 %
26	TOTAL G-NGV	3,150	.60071	1,892	3,150	.49940	1,573	-.10130	-16.9 %

APPENDIX H
Page 2

PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
CORE TRANSPORT RATES AND REVENUES

Line		FORECAST REVENUES USING PRESENT RATES EFFECTIVE 1/1/92			FORECAST REVENUES USING RATES FORECAST FOR AUG 92			CHANGE IN RATES	
		Adj.Bill.Det.	Rate	Revenue	Adj.Bill.Det.	Rate	Revenue		
		MTH or CUST	$/TH	$000	MTH or CUST	$/TH	$000	$/TH	%
No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	RES. NON-LIRA								
1	Tier I (Baseline)	5,882	.28526	1,678	5,882	.32812	1,930	.04286	15.0 %
2	Tier II	1,500	.60544	908	1,500	.50143	752	-.10401	-17.2 %
3	Subtotal Non-LIRA	7,382	.35030	2,586	7,382	.36333	2,682	.01302	3.7 %
	RES. LIRA								
4	Tier I (Baseline)	513	.20407	105	513	.25208	129	.04801	23.5 %
5	Tier II	131	.47622	62	131	.39907	52	-.07715	-16.2 %
6	Subtotal LIRA	643	.25936	167	643	.28195	181	.02258	8.7 %
7	Total Residential	8,025	.34301	2,753	8,025	.35680	2,863	.01379	4.0 %
	SCHEDULE G-NR1								
8	Customer Charge	4,171	13.14	1,315	4,171	14.60	1,462	1.46	[illegible]
9	Summer Vol. Rate	17,550	.26058	4,573	17,550	.26185	4,595	.00127	0.5 %
10	Winter Vol. Rate	16,020	.43584	6,982	16,020	.41222	6,604	-.02362	-5.4 %
11	Total G-NR1	33,570	.38340	12,871	33,570	.37714	12,661	-.00626	-1.6 %
	SCHEDULE G-NR3								
12	Customer Charge	6	139.40	19	5.8	163.94	23	24.54	17.6 %
13	Summer Rate	1,870	.19301	361	1,870	.20684	387	.01383	7.2 %
14	Winter Rate	2,140	.34185	732	2,140	.33795	723	-.00390	-1.1 %
15	Total G-NR3	4,010	.27725	1,112	4,010	.28246	1,133	.00521	1.9 %
16	Commercial Transport	37,580	.37207	13,982	37,580	.36704	13,793	-.00503	-1.4 %
17	Total Core Transport	45,605	.36696	16,735	45,605	.36524	16,657	-.00172	-0.5 %
18	TOTAL CORE	6,204,482		3,712,374	6,204,482		3,280,142		

A.91-11-001 **

APPENDIX H
Page 3

PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
INDUSTRIAL, UEG, & COGENERATION TRANSPORT RATES AND REVENUES

Line No.	(A)	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 1/1/92 Adj.Bill.Det. MTH or CUST (B)	Rate $/TH (C)	Revenue $000 (D)	FORECAST REVENUES USING RATES FORECAST FOR AUG 92 Adj.Bill.Det. MTH or CUST (E)	Rate $/TH (F)	Revenue $000 (G)	CHANGE IN RATES $/TH (H)	% (I)
	INDUSTRIAL								
	SCHEDULE G-FT								
1	Customer Charge	552.41	463.57	8,146	552.41	602.75	7,991	139.19	30.0 %
2	Summer Volumetric	1,161,850	.12016	139,608	1,161,850	.11241	130,606	-.00775	-6.4 %
3	Winter Volumetric	865,270	.13724	118,750	865,270	.12887	111,509	-.00837	-6.1 %
4	Avg. Std. Rate (adj. vol.)	2,027,120	.13048	264,503	2,027,120	.12338	250,106	-.00710	-5.4 %
5	Avg. Rate (unadj. vol.)	2,027,120	.13048	264,503	2,027,120	.12338	250,106	-.00710	-5.4 %
	SCHEDULE G-IT								
6	Customer Charge	356.55	463.57	3,967	356.55	602.75	5,158	139.19	30.0 %
7	Summer Volumetric	850,756	.09509	80,898	852,088	.07518	64,064	-.01991	-20.9 %
8	Winter Volumetric	459,068	.11218	51,498	460,023	.09164	42,159	-.02054	-18.3 %
9	Avg. Std. Rate (adj. vol.)	1,309,823	.10411	136,363	1,312,111	.08489	111,380	-.01922	-18.5 %
10	Avg. Rate (unadj. vol.)	1,337,350	.10197	136,363	1,337,350	.08328	111,380	-.01868	-18.3 %
	INDUSTRIAL AVERAGES								
11	Customer Charge	908.96	463.57	10,113	908.96	602.75	13,149	139.19	30.0 %
12	Summer Volumetric	2,012,606	.10956	220,506	2,013,938	.09666	194,670	-.01290	-11.8 %
13	Winter Volumetric	1,324,338	.12855	170,248	1,325,293	.11595	153,668	-.01260	-9.8 %
[illegible]	Avg. Std. Rate (adj. vol.)	3,336,943	.12013	400,867	3,339,231	.10825	361,487	-.01188	-9.9 %
[illegible]	Avg. Rate (unadj. vol.)	3,364,470	.11915	400,867	3,364,470	.10744	361,487	-.01170	-9.8 %
	UEG								
16	Customer Charge	1	84,475	2,027	1	93,856	2,253	9,381	11.1 %
17	Demand Charge			213,865			271,389	57,525	26.9 %
18	Tier I Volumetric	541,162	.04581	24,791	744,087	.04298	31,980	-.00283	-6.2 %
19	Tier II Volumetric	3,480,928	.01352	47,062	3,278,003	.00841	27,557	-.00511	-37.8 %
20	Avg. Rate	4,022,090	.07154	287,745	4,022,090	.08284	333,180	.01130	15.8 %
	COGEN								
	G-COG Firm								
21	Summer Volumetric	349,987	.09719	34,015	349,987	.08992	31,473	-.00727	-7.5 %
22	Winter Volumetric	238,151	.11131	26,509	238,151	.10597	25,238	-.00534	-4.8 %
23	Avg. Rate	588,138	.10291	60,524	588,138	.09642	56,710	-.00648	-6.3 %
	G-COG Interruptible								
24	Summer Volumetric	175,322	.07213	12,646	175,322	.05270	9,239	-.01943	-26.9 %
25	Winter Volumetric	139,787	.08624	12,055	139,787	.06875	9,610	-.01749	-20.3 %
26	Avg. Rate	315,108	.07839	24,701	315,108	.05982	18,849	-.01857	-23.7 %
	G-COG Averages								
27	Summer Volumetric	525,309	.08883	46,661	525,309	.07750	40,712	-.01133	-12.8 %
28	Winter Volumetric	377,938	.10204	38,564	377,938	.09221	34,848	-.00983	-9.6 %
29	Avg. Rate	903,247	.09435	85,225	903,247	.08365	75,559	-.01070	-11.3 %
30	G-P03 Firm	250,638	.08452	21,185	250,638	.09643	24,169	.01191	14.1 %
[illegible]	G-P03 Interruptible	92,732	.06710	6,222	92,732	.05992	5,557	-.00718	-10.7 %
[illegible]	G-P03 Averages	343,369	.07982	27,407	343,369	.08657	29,726	.00675	8.5 %
33	Total COGEN	1,246,616	.09035	112,632	1,246,616	.08446	105,285	-.00589	-6.5 %
34	GC2 Revenue	68,004		5,883	68,004		5,664		
35	COGEN Including GC2	1,314,620	.09015	118,515	1,314,620	.08440	110,949	-.00576	-6.4 %

APPENDIX B
Page 4

PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
WHOLESALE AND SUMMARY OF NONCORE TRANSPORT RATES AND REVENUES

Line No.	(A)	FORECAST REVENUES USING PRESENT RATES EFFECTIVE 1/1/92 Adj.Bill.Det. MTH or CUST (B)	Rate $/TH (C)	Revenue $000 (D)	FORECAST REVENUES USING RATES FORECAST FOR AUG 92 Adj.Bill.Det. MTH or CUST (E)	Rate $/TH (F)	Revenue $000 (G)	CHANGE IN RATES $/TH (H)	% (I)
	WHOLESALE								
1	Demand Charge			24,093			26,364	2,271	9.4 %
2	Volumetric Rate	292,940	.00616	1,805	292,940	.00529	1,550	-.00087	-14.1 %
3	Avg. Rate	292,940	.08841	25,897	292,940	.09529	27,914	.00689	7.8 %
	TOTAL NC TRANSPORT								
4	Adjusted volumes	8,966,593	.09290	833,024	8,968,881	.09294	833,529	.00003	0.0 %
5	Unadjusted volumes	8,994,120	.09262	833,024	8,994,120	.09267	833,529	.00006	0.1 %
	CORE SUBSCRIPTION								
6	Industrial & COGEN	722,780	.19253	139,154	722,780	.19140	138,337	-.00113	-0.6 %
7	UEG	2,614,370	.19253	503,333	2,614,370	.19140	500,379	-.00113	-0.6 %
8	Wholesale	138,470	.19217	26,609	138,470	.19104	26,454	-.00112	-0.6 %
9	Total NC Procurement	3,475,620	.19251	669,096	3,475,620	.19138	665,170	-.00113	-0.6 %
	REVENUE SUMMARY								
	Core								
10	Transport			16,735			16,657	-78	-0.5 %
11	Bundled			3,697,531			3,264,014	-433,517	-11.7 %
12	Total Core			3,714,267			3,280,671	-433,596	-11.7 %
	Noncore								
13	Transport			833,024			833,529	505	0.1 %
14	EOR-CPUC Revenue			570			570		
15	Procurement			669,096			665,170	-3,926	-0.6 %
16	Gas cost adjustment						0		
17	Total Noncore			1,502,690			1,499,270	-3,421	-0.2 %
18	Total			5,216,957			4,779,940	-437,016	-8.4 %

PACIFIC GAS AND ELECTRIC COMPANY
1992 GAS BIENNIAL COST ALLOCATION PROCEEDING
WHOLESALE RATES

	PALO ALTO	COALINGA	CP NATIONAL	SOUTHWEST GAS	
Aug-92	$148,209	$5,541	$2,828	$526,350	1
Sep-92	$163,774	$7,388	$2,828	$536,172	2
Oct-92	$211,214	$6,464	$3,771	$555,860	3
Nov-92	$329,908	$12,005	$3,771	$730,146	4
Dec-92	$426,653	$25,857	$8,485	$1,095,893	5
Jan-93	$466,988	$37,862	$15,084	$1,295,414	6
Feb-93	$349,552	$23,086	$16,027	$1,195,587	7
Mar-93	$342,421	$32,321	$8,485	$1,041,624	8
Apr-93	$280,369	$10,158	$3,771	$829,861	9
May-93	$220,790	$10,158	$943	$672,357	10
Jun-93	$168,969	$7,388	$2,828	$601,405	11
Jul-93	$149,910	$3,694	$4,714	$546,018	12
Aug-93	$148,209	$5,541	$2,828	$532,601	13
Sep-93	$163,774	$7,388	$2,828	$543,316	14
Oct-93	$211,214	$6,464	$3,771	$565,683	15
Nov-93	$329,908	$12,005	$3,771	$748,898	16
Dec-93	$427,515	$25,857	$8,485	$1,134,291	17
Jan-94	$466,988	$37,862	$15,084	$1,295,414	18
Feb-94	$350,624	$23,086	$16,027	$1,195,587	19
Mar-94	$342,421	$32,321	$8,485	$1,041,624	20
Apr-94	$280,369	$10,158	$3,771	$829,861	21
May-94	$220,790	$10,158	$943	$672,357	22
Jun-94	$168,969	$7,388	$2,828	$601,405	23
Jul-94	$149,910	$3,694	$4,714	$546,018	24
TOTAL	$6,519,448	$363,844	$147,070	$19,333,742	25
Vol. Charge ($/th)	0.00515	0.00551	0.00563	0.00533	26

(END OF APPENDIX H)