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DEC 16 1992

Decision 92-12-057 December 16, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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| Application of PACIFIC GAS AND ELECTRIC COMPANY for Authority, Among Other Things, To Increase Its Rates and Charges for Electric and Gas Service.<br><br>(Electric and Gas) (U 39 M) | Application 91-11-036<br>(Filed November 26, 1991) |
| And Related Matters. | Application 91-08-049<br>Application 90-04-003<br>I.92-02-002<br>I.90-02-043 |

(See Appendix A for appearances.)

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## FIRST INTERIM OPINION: PHASE 1 ISSUES

### 1. Summary of Decision

This First Interim Opinion decides Phase 1 issues in the Test Year 1993 general rate case (GRC) of Pacific Gas and Electric Company (PG&E). The major issues are test year revenue requirement, including appropriate levels of compensation for PG&E's employees; research, development, and demonstration (RD&D) activities; the Joint Recommendation for demand-side management (DSM); the Clean Air Vehicle (CAV) program; a NOx retrofit recovery mechanism; methodological advancements in marginal cost development and refinements in revenue allocation.

The principal result of this decision is to authorize PG&E an increase over revenues at present rates of 3.42% for the Electric Department and 2.86% for the Gas Department. These figures are based on the January 1, 1993 consolidated changes in revenues reflecting the Return on Rate (ROR) Base adopted in Application (A.) 92-05-006 et al., and our decision on revenue requirement for the Electric Department in A.92-04-001.

In adopting these increases, we have reduced PG&E's request for the Electric Department by $121,925,000 and $41,786,000 for the Gas Department. Our reductions in these areas were based on the inadequacy of PG&E's affirmative showing. Likewise, for the areas where we approved PG&E's request, PG&E met its burden of proof.

Generally, we have found PG&E's compensation levels supported by the record. However, we have made a slight reduction and require further information in PG&E's next GRC. In addition, we hold that Post-Retirement Benefits Other Than Pensions (PBOPs) shall be handled consistently with our decision in Investigation (I.) 90-07-037.

Overall, in the areas of marginal cost and revenue allocation, we adopt PG&E's proposals. We believe PG&E proposals advance the accuracy of marginal cost pricing, and send more correct signals to consumers. Likewise, PG&E's proposal overall presents a more accurate representation of the agricultural class' nearness to Equal Percentage of Marginal Cost (EPMC).

## 2. Procedural Background

The long road leading to issuance of this decision began when PG&E filed its Notice of Intent (NOI) on August 16, 1991. This filing began the process for a December 1992 decision pursuant to the rate case plan set out in Decision (D.) 89-01-040. At roughly the same time PG&E filed its NOI, it also provided substantial responses to Division of Ratepayer Advocates' (DRA) master data request.

DRA indicated some 29 deficiencies in the NOI. After correcting and resolving these deficiencies, the NOI was accepted by letter of Executive Director on September 26, 1991. Sixty days after the acceptance of the NOI, PG&E filed Application (A.) 91-11-036 on November 26, 1991, requesting significant rate increases.

The original application requested authorization to increase revenue recovery over rates in effect on November 26, 1991, by $609,654,000 for the Electric Department and $221,595,000 for the Gas Department, for a combined increase of $831,549,000. These increases equate to an 8.2% increase for the electric side of the business and an 8.7% increase for the gas portion of the company, resulting in an overall increase of 8.3%.

A prehearing conference was held before the assigned administrative law judges (ALJs) on January 10, 1992. Several procedural matters were discussed and based on those representations and the rate case plan, the ALJs issued a ruling, dated January 17, 1992, establishing a schedule for the evidentiary hearings to begin on March 19, 1992. It was determined that all issues other than rate design would be heard in Phase 1 of this application pursuant to the rate case plan.

In addition, the ALJs' ruling adopted PG&E's recommendation that the electric sales forecast used in this proceeding would be the same as that adopted in PG&E's 1992 Energy Cost Adjustment Clause (ECAC) proceeding.

In addition, PG&E's motion for a protective order with respect to certain computer models and input data was granted. Finally, the ALJs' ruling consolidated the Geysers Unit 15 I.90-02-043) and related case A.90-04-003, with this GRC.

Meanwhile, as required by the rate case plan, on January 15, 1992, PG&E filed a revised results of operation proposed exhibit. This exhibit (PG&E Exhibit 21) reduced PG&E's requested increase to $475,597,000 for the Electric Department, and $118,756,000 for the Gas Department, or a combined total of $594,353,000. This $237 million reduction from PG&E's original application reflects the impact of the January 1992 rate changes that resulted from the 1992 attrition decision and the lowered 1992 authorized return on equity of 12.65%. These numbers continued to change as the proceeding progressed.

As is the norm in GRCs, the Commission instituted an investigation to be a companion case to this application. The purpose of this investigation is for the Commission to have a procedural forum and vehicle to fully act on recommendations on revenue requirement, rates, practices, adequacy of electric and gas transmission and/or storage facilities, and other aspects of PG&E's operations which may be beyond the confines of the relief requested in A.91-11-036. Thus, I.92-02-022 was consolidated with A.91-11-036 on February 5, 1992 by order of the Commission.

Ordinarily, we do not comment on various procedural motions that the ALJ handles during the course of the case. However, we wish to affirm the ALJ's proper handling of a particular motion prior to the commencement of hearings. Six parties to the proceeding (calling themselves "the Gang of Six") filed a motion to exclude certain evidence relating to PG&E's

proposed changes in marginal cost methodology. The moving parties were: the California Department of General Services (DGS), the California Large Energy Consumers' Association (CLECA), the California Manufacturers' Association (CMA), the Federal Executive Agencies (FEA), the Industrial Users (IU), and Toward Utility Rate Normalization (TURN). These parties requested the Commission to dismiss prior to hearings PG&E's proposals for area-specific transmission and distribution costs development, area-specific load development, and the Present Worth method calculations of these costs on the grounds that the proposals were so complex and data-intensive that they constituted a "black box" that could not be adequately tested, replicated, or verified by anyone including the Commission and its staff. Not surprisingly, the motion was opposed by PG&E in addition to several other parties. The Agricultural Energy Consumers' Association (AECA), the California Farm Bureau Federation (CFBF), the California City-County Streetlight Association (Cal-SLA), and the Association of California Water Agencies (ACWA) joined PG&E in opposing the motion. PG&E's position was that these new proposals were no more complex than other previous methodological advances such as the ELFIN and PROMOD computer models, and frankly nowhere near as radical as the Commission's shift from embedded costs to marginal costs. Oral argument was held on the motion on March 23, 1992. The ALJ denied the motion in its entirety. We agree with the ALJ ruling and will discuss the subject matter of the motion and its underlying merits in a later section in this decision. As this later section will bear out, we believe it is important to allow parties to come forward with new ideas and suggest improvements to our current methodologies. The objecting parties seemed well able to deal with the issues by the time of hearings.

Some 57 days of hearings have been held in this proceeding resulting in nearly 5,500 pages of transcripts, 268 exhibits have been received in evidence with pages numbering in the thousands, and briefs totaling nearly 1,500 pages have been received from many parties.

In addition to the parties already mentioned, we received briefs from the California Energy Commission (CEC), the Coalition for Energy Efficiency and Renewable Technologies (CEERT), the Cogeneration Service Bureau (CSB), the County of Lake (County), the Union Intervenors (Unions), and the Natural Resources Defense Council (NRDC).

In addition to the filing of their briefs, PG&E and DRA submitted a Comparison Exhibit (Exhibit 235) on July 8, 1992 as required by the rate case plan. The Comparison Exhibit compares PG&E's and DRA's analyses of the 1993 Test Year showings on results of operations, resource assumptions, marginal costs, and revenue allocation, among other issues. In the Comparison Exhibit, PG&E presented further revised results of operations which modified the company's 1993 GRC requested increase to $412,143,000 for the Electric Department and $85,623,000 for the Gas Department or a total of $497,776,000. These Comparison Exhibit numbers showed yet another decrease in the total requested increase PG&E was seeking.

The overall requested rate increases changed once again in the September Update exhibit (Exhibit 237) and again in the consolidated ECAC/GRC request to $484 million. Based on the ALJ proposed ROR in A.92-05-009 the number changes again to $393 million. We note PG&E does not endorse the proposal in the cost of capital proceeding. Phase 1 of this proceeding was submitted as of October 6, 1992.[1]

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1 Additionally, we wish to acknowledge the fine job done by the project managers for both PG&E and DRA in their efforts to be cooperative and produce excellent comparative exhibits for our use. Winifred Walters from PG&E and Bill Y. Lee from DRA are both to be commended.

3. Public Participation Hearings

In an effort to get opinions from the affected ratepayers regarding PG&E's requested rate increase, the ALJs travelled to nine locations in PG&E's service area convening public participation hearings: Santa Rosa, Willits, Auburn, Chico, Dublin, Watsonville, Bakersfield, Fresno, and San Francisco. Nearly 100 people made statements at these hearings. In addition, Commissioner John Ohanian attended the public participation hearing in Fresno. The Commission also received over 400 letters from PG&E customers, nearly all of whom object to the rate increase requested by PG&E.

While many letters and speakers at public participation hearings had unique concerns, there were several consistent themes.

Most speakers believed that PG&E's rates are increasing far more rapidly than people's incomes and other factors such as consumer price indices. They believe rates are already too high for the average ratepayer, but especially onerous for seniors and people with low and fixed incomes. Another common theme was that the economic times do not warrant an increase. They point out that unemployment and the recession are making it very difficult for people to make ends meet. Thirdly, many ratepayers noted that the conservation measures that had been encouraged by PG&E are not paying off. Several people commented that while they have cut their energy usage dramatically their energy bills continue to rise.

In nearly every location there were many representatives of the farming community. The farmers pointed out that energy costs are a large proportion of their overall costs of production, ranging anywhere from 15% to 25%. They claim that increases in rates continue to contribute to agriculture's decline and loss of productivity for the State. Farmers believe that it is unfair for them to continue to shoulder rate increases when much of the growth driving up PG&E's rates come from business and from housing replacing agricultural land. Therefore, farmers believe that they should not be responsible for costs caused by new growth. In addition, the farmers argued that the high energy costs are forcing more and more farmers to convert to diesel fuel generators which is in conflict with the overall goals of increased environmental protection which PG&E espouses. Finally, farmers complain that the State of California is sending them contradictory messages. On the one hand, government entities involved in water tell farmers that surface water must go to urban areas while at the same time this Commission's rate policies continue to drive up the costs of pumping groundwater.

Many farmers pointed out the irony that water conservation techniques in fact often result in using more power at increasingly expensive rates. Several farmers urge the Commission to consider carefully the new methodologies of cost allocation that are being proposed by PG&E for various customer classes. It is their contention that the agricultural class as a group is already paying its fair share. "Farmers are voting with their dollars and moving out of PG&E." (RT 6:193.) The farmers testified that many of the very largest agricultural users have already left PG&E's system. They contend that this proposed rate increase will drive smaller farmers off the system also. Then PG&E will be in position at having lost the margin that those farmers provide in addition to the increase in air pollution that will result from leaving PG&E's system. The ALJ also directed PG&E to address the issue of farmers using diesel engines and its impact on air quality during the evidentiary phase of the hearings.

Another issue that came out at several different locations of the public participation hearings was the issue of employee discount that PG&E gives as a perquisite or benefit of employment. The ALJ ordered PG&E to address that issue during evidentiary hearings. The evidence indicated that it would be more costly to compensate PG&E employees for the loss of the employee discount than it is to give the employee discount. In addition, PG&E does not believe that the employee discount results in its employees using more power than the average customer.

Finally, the ALJ ordered PG&E to follow up with specific customer problems raised at the hearings and report the results to her by letter. PG&E has complied with her request.

We sympathize with the concerns raised by all speakers and authors of letters sent to us regarding PG&E's requested rate increase and have taken those concerns seriously in making the decisions we reach today.

## 4. Sales Forecast and Present Rate Revenues

PG&E and DRA agreed to use the electric sales forecast determined in the 1992 ECAC proceeding for this GRC. Therefore, the numbers set forth in the final ECAC decision are incorporated into the Appendices attached here.

For the gas sales forecast, we rely on our recently adopted Biennial Cost Allocation Proceeding (BCAP) decision, D.92-10-051 for the appropriate numbers for use in our appendices to this decision.

## 5. Compensation for Employees

### 5.1 Overview

Once again, the issue of whether PG&E's compensation to its employees is set at reasonable levels was the subject of controversy during this proceeding. In addition to the controversy on whether PG&E pays its employees too much, there was also an issue of whether PG&E had complied with Ordering Paragraph 12 of the last GRC decision, D.89-12-057 (34 CPUC2d 199 (1989)). DRA recommends a substantial penalty against PG&E for failing to comply with the last GRC decision. At issue is whether PG&E's compensation report filed in this case was supposed to include an analysis of pensions and benefits along with compensation. Because DRA believes that PG&E failed to comply with the order, DRA recommends that PG&E be given no labor escalation from the last recorded year, a recommendation which effectively results in disallowance of nearly a $120 million for ratemaking purposes. In addition, DRA argues that limiting recovery of PG&E's pay rates, which DRA claims to be 8.5% above market average rates, also should result in a disallowance worth some $54 million. CLECA supports DRA in its recommendations.

Not surprisingly both PG&E and the Unions disagree both with DRA's analysis of what was required in the last GRC decision and with the belief that paying wages slightly over market parity is unreasonable. PG&E and the Unions point to the labor productivity gains that PG&E has experienced in the last several years and argue that the efficiency wage theory supports payment of higher than market average wages in order to reduce turnover, save money on job retraining, and increase productivity.

As on all issues in this GRC, the burden of proof of showing that its level of compensation is reasonable rests with the applicant, PG&E. As will be discussed on the following sections, while we believe that PG&E has met its burden of proof in this area, we will reduce to 5% above market the compensation levels PG&E has requested for ratemaking purposes.

<u>5.2 Compliance With Last GRC Decision</u>

DRA contends that PG&E is not in compliance with Ordering Paragraph 12 of the last GRC decision.

> "12. In its next general rate application PG&E shall provide a full affirmative presentation on the level of overall compensation and the comparison to similar compensation levels in the relevant job markets." (34 CPUC2d 199, 439.)

DRA contends that the term "overall compensation" in the above ordering paragraph means that this presentation should include information on compensation <u>and benefits</u> for employees. PG&E disagrees with this interpretation.

DRA admits that it never informed PG&E of its opinion that the study presented in this GRC should include a combined compensation and benefits analysis. In fact, in several conversations and meetings leading up to the NOI filing, the DRA witness who later testified in this proceeding did not make this position known to PG&E personnel. The DRA witness, Arthur Jimenez, testified that it was after a decision was issued in Southern California Edison Company's (Edison) most recent GRC that he reached the conclusion that PG&E's study should include both compensation and benefits. Mr. Jimenez apparently reads the ordering paragraph from that GRC decision the same as the PG&E ordering paragraph in question.

> "44. In its next general rate case, Edison shall file or serve testimony on the following topics:
>
> "a. Wages and salaries, with increased emphasis on total compensation, <u>total benefits as a percentage of cash compensation</u>, and the distribution of total compensation among comparable terms." (D.91-12-076, mimeo. p. 225, Ordering Paragraph 44. Emphasis added.)

This decision, relating to a different utility, was issued nearly <u>one month after</u> PG&E filed its application and testimony in this proceeding. In addition, a DRA representative discussed D.89-12-057 with the assigned ALJ and confirmed that it was the Commission's order that when reviewing overall compensation levels salaries, wages, and benefits were to be reviewed separately and together. (Exhibit 116.) Unfortunately, the word benefits is noticeably absent from Ordering Paragraph 12. Further, the fact that DRA sought an interpretation from the ALJ is evidence of the ambiguity of the ordering paragraph. Our decisions speak for themselves. Any additional "interpretation" of our decisions that may be needed should be rendered only in subsequent decisions by the Commission.

It is PG&E's position that "overall compensation" meant a study that included base pay plus any incentive pay program. PG&E points out that the Commission Advisory and Compliance Division (CACD) held workshops after the last GRC precisely on the incentive pay issue. PG&E attached to its Exhibit 10 a copy of the Management Incentive Plan Workshop Report issued by CACD in May 1991. PG&E contends that it is patently unfair for DRA to now claim that they should have included a benefits analysis in its compensation study. PG&E points out the obvious: first, the Edison decision issued in December 1991 does not apply to PG&E and second, the decision postdates PG&E's testimony in this proceeding.

We agree it would be grossly unfair to hold PG&E to standard set in another utility's rate case in a later time frame. In addition, the Edison ordering paragraph, while it has no relevance for PG&E's showing, does in fact, have the word benefits in its directive. We can only hold PG&E responsible for what the ordering paragraph that applies to it says on its face.

In light of this analysis, we will reject DRA's requested penalty of some $120 million. PG&E's compensation total cash compensation study (Exhibit 10) is in compliance with the last GRC's Ordering Paragraph 12. PG&E reasonably relied both on DRA's earlier representations, the subject matter of the CACD workshop on incentive pay, and most importantly, the actual language of the ordering paragraph to develop the scope of its total cash compensation study.

Finally, we note that PG&E's witness in the human resources area testified that his own department is called Compensation and Benefits. Further, he testified, that the literature regarding the subject area compensation and benefits usually used the two words separately. (RT 13:790.)

Therefore we reject DRA's recommendation that PG&E receive no labor escalation. In addition, we note that DRA's own witness testified to the extreme difficulty of trying to proceed with a combined compensation and benefits study. We will address what we wish PG&E to do in its next GRC in the final section on compensation.

## 5.3 Reasonableness of PG&E's Compensation Strategy

### 5.3.1. PG&E's Showing

PG&E presented through witness Mr. Broman a full affirmative showing of PG&E's compensation. (Exhibit 10.) PG&E contends that this exhibit is comprehensive in describing the objectives, strategy, economic basis, and market comparison, within the limits of survey accuracy, of PG&E's compensation.

PG&E argues that this exhibit shows that PG&E's compensation objective, to pay slightly above the weighted market average, is reasonable and appropriate to attract, retain, and motivate employees that are critical to meeting customer needs. (RT 13:705.) The exhibit includes as part of total cash compensation its incentive plan called Performance Incentive Plan (PIP). PG&E points out that DRA's compensation witness makes no objection to PIP in its compensation exhibit.

PG&E emphasizes that its objective of paying slightly above the market average does not mean that PG&E pays higher salaries compared to all firms or for all positions. Rather, PG&E's salaries are generally at the 60th percentile, which means that PG&E salaries are still below that paid by 40% of the firms in the labor market. (RT 13:706.)

The economic basis for PG&E's compensation strategy was described by several witnesses in this proceeding. PG&E's compensation objective is to provide total cash compensation (TCC) which is slightly above the weighted market average in order to attract, retain, and motivate a highly qualified work force critical to the company's success. Currently, slightly above is defined as 5% above the weighted market average for nonattorney positions. (Exhibit 10, p. 10-6.) The original description of this premise, called the efficiency wage theory, was developed by

George Akerlof of the University of California, Berkeley. The efficiency wage theory suggests that it is more efficient and minimizes overall costs, to provide levels of wages or TCC that are slightly higher than current market rates. This will allow the company to attract and retain above-average performers. This in turn lowers turnover and training costs and improves productivity. The efficiency wage theory holds that the resulting financial savings exceed the additional expense of paying slightly above the market average. PG&E points out that the Commission has agreed with this objective in a prior GRC decision:

> "A small premium above market does benefit the ratepayer (and stockholder) particularly with regard to safeguarding PG&E's investment in employee training." (23 CPUC2d 149, 182 (1986).)

PG&E contends that empirical evidence supports its contention that higher productivity outweighs the costs associated with PG&E's compensation policies. (Exhibit 221, p. 8-4.) PG&E goes on to identify numerous benefits of its compensation strategy which are greater than the proposed disallowance by DRA. PG&E argues that it avoids between $60 million and $90 million in extra costs associated with a turnover rate that would be closer to the national average, but for its compensation strategy. PG&E argues that its turnover rates are significantly lower than the national average because of its support of the efficiency wage theory and resulting compensation strategy.

In addition, PG&E argues that cost savings of $150 million are realized through employing a more productive work force. In response to criticism that other companies are laying off workers and downsizing due to the recession, PG&E points out that it began its process of restructuring and "rightsizing" more than four years ago, in 1987 and 1988, well before many other companies.

PG&E conducted comprehensive surveys in order to determine whether its compensation strategy is reasonable. PG&E found that its compensation is within 3.3% of its target compensation objective of paying 5% above average market wage. The methodology used in the PG&E exhibit on cash compensation (Exhibit 10) is similar to that employed in several previous market comparison studies that have been used by the Commission. PG&E went through a process of using job matching and comparisons with firms with similar types of labor needs. PG&E believes that the result is a representative description of the market compensation within a range of accuracy of about 10%. (RT 14:794.)

In reaching that conclusion, PG&E relied on published analyses of error in wage surveys. The literature generally supports the proposition that published survey data should be considered accurate within the range of approximately plus or minus 10%. (PG&E Exhibit 10.) Since it is PG&E's goal to be slightly above or at 105% of the market, the results of the survey, which indicate that PG&E is 8.5% above market average, are statistically insignificant given that there is a 10% range of survey error.

Additionally, PG&E chose to apply a conservative methodology to its total cash compensation study. PG&E did not adjust data for employee performance, for tenure, job size and scope, size of company, or geographic location. In fact, if PG&E had used geographical adjustments, PG&E could have adjusted its survey data by up to 24%, which would depict PG&E's salaries as being below the market average. (Exhibit 221, Chapter 7, Attachment 2, p. 4-5.)

PG&E disagrees with DRA's apparent unwillingness to accept any correlation between pay policies and productivity.

In sum, PG&E has demonstrated labor cost benefits, along with above average gains in labor productivity, that far outweigh any costs that may be associated with it. Even if the estimated

$210 to $250 million in savings were cut in half, PG&E argues that they would still outweigh the recommended DRA disallowance.

5.3.2 Unions' Showing

Of PG&E's 26,976 employees, 18,044 or 67% are represented by unions in collective bargaining.[2] The Unions put forward an impressive showing in this proceeding. Eleven different witnesses testified, all with impressive backgrounds, professional expertise, and knowledge related to compensation practices. Overall the Unions believe that the evidence fully supports PG&E's assertion that the total compensation for union-represented employees is reasonable and should be fully recovered in rates. In addition, the Unions believe that as a matter of evidence, law, and sound regulatory policy, the DRA should not interfere in the collective bargaining and compensation policy.

The Unions point out that unlike other cases, DRA made no effort to conduct a wage and salary study itself in this proceeding, limiting itself to merely critiquing PG&E's study. The Unions did analyze PG&E's survey methodology quite thoroughly. The Unions point out that by definition wage and salary surveys are subject to considerable error. In one witness' opinion, PG&E's total cash compensation exceeds the "market" by only 7.37% rather than the 8.5% referred to by DRA. The Unions went on to point out various errors that are likely to occur even when surveys are conducted in an objective and professional fashion.

First, error may result from the sample chosen for the survey. Any wage study, other than a census enumerating every

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2 Local 1245 of the International Brotherhood of Electrical Workers, AFL-CIO, represents 3,910 clerical employees and 12,427 physical employees. The Engineers and Scientists of California, MEBA, AFL-CIO, represent 1,622 professional and technical employees. These unions shall be collectively referred to in this decision as Unions.

labor market participant's actual wage salary, is by definition incomplete since it is a sample drawn from a population. The degree to which survey participants are representative of the entire labor market is known as sampling error. (Exhibit 354, pp. 3-4 and 2-4.) Second, error may result during the matching process. Improper job matches that result in wages close to the survey average may not be flagged as errors, while proper matches far from the survey mean may be improperly discarded. Third, the Unions point out that firms may submit inaccurate data, or errors may be introduced when the data is transformed or coded. The Unions contend that because of inherent difficulty in gathering information on otherwise confidential compensation data, there are endemic insignificant reporting problems which mean that wage and salary survey analysts must expect a relatively large risk of statistical error.

The Unions point out in this proceeding no information on standard deviation of surveyed wages (the most commonly used statistical measure of error) is available, and the surveys used by PG&E make no claims of statistical accuracy or representativeness. Rather, the user of the surveys is warned to exercise caution and judgment in assessing the representativeness of each survey. (Exhibit 354, p. 3-4.)

The Unions point out that if one were to accept PG&E's estimate that the wage surveys it used are accurate plus or minus 10%, then PG&E's finding of an overall wage level 8.5% above the "market" has no statistical significance. (Exhibit 309, pp. 6-3, 7-4, and 8-7 through 8-9.)

The Unions go on to point out that any analysis of wage survey data must also take into account not only survey error, but also survey bias. The Unions point out four choices in the underlying surveys used by PG&E that biased downward the measure of "market" pay. First, the Unions point out that PG&E's long unionized work force is compared to other workers, irrespective of their union status. Especially with clerical workers, the surveys include for the most part firms with work forces which are not unionized. Because unionized workers are paid on the average 15% more than nonunion workers, the choice of nonunion survey participants biases the "market" downward. (Exhibit 354, p. 3-6; Exhibit 309, pp. 5-6 through 5-7.) Second, the Unions contend that bias is introduced because the survey does not compare wages at firms similar in size to PG&E. Large firms pay employees more than small firms. PG&E is one of the largest employers in northern California. Third, geographic pay differentials biased the PG&E's survey, again by forcing downward the "market" rate. The San Francisco area has one of the highest costs of living in the United States, and one of the highest general wage levels. Although the wage surveys which PG&E used include data from throughout the western United States, PG&E did not correct for systematic pay differences across regions, thus once again biasing downward the "market" wage. Finally, PG&E did not limit its survey to firms with work forces with similarly highly tenured work forces. Workers typically earn about 2% more for each year of experience. Utilities tend to have both lower turnover and higher seniority than other industries. This increase in seniority results in overall wages being higher than companies with a less experienced work force. (Exhibit 309, pp. 7-5, 9-7, 9-8.)

The Unions contend that PG&E's failure to make adjustments to its raw survey data to account for firm's size, tenure, region, and unionization result in its data being extremely conservative. The Unions express the opinion that this was undoubtedly motivated by a desire to be above criticism from DRA. The Unions point out that in other cases DRA has adjusted market wages for firm's size and region, although not for unionization or experience. (Unions Opening Brief p. 10.) Finally, the Unions question what meaning, if any, the Commission should attach to the observed deviation of PG&E wages from "market" wages. The Unions point out that wage surveys typically show very large differences between the wages of the highest and lowest paid employees in an occupation, even in unregulated, competitive, profit maximizing industries. The raw data for a typical survey will invariably indicate tremendous dispersion around the mean for any given classification. What is reported as the "market" wage for an occupation is nothing more than a convenient measure for communication purposes. In a free market economy, the Unions contend, there are no rules that require employers to pay a specific wage for every job, and thus should not be used as a proxy for actual labor rates.

In conclusion, the Unions' view on the correctness of PG&E's compensation objectives is best summed up by one of PG&E's system operators:

> "We work schedules that would drive many people crazy. We work with a knowledge that a single mistake could cost our employer millions of dollars. We also know that a single mistake can bring inconvenience, and possibly danger, to thousands of our fellow citizens. . . . We are proud of the job we do. You can see that pride in the quality of our work, in the quality of the service we provide. When you attack our wages, you're attacking that pride. This power system is not run by averages or formulas or calculations. It is run by people. We run it. It's our job, and we give it a 100%. . . . This is not an accounting issue. This is not a matter to be lost to number crunchers. This is a public policy issue. The public would not be served by the degradation of our wages, of our pride, of our work, by a vote of 'no confidence' in PG&E's system operators.
>
> "Remove this cloud from over our heads. Put this matter to rest. And let us continue doing the job we are paid to do." (Exhibit 309, pp. 11-9 through 11-10.)

5.3.3 DRA's and CLECA's Criticisms

Both DRA and CLECA fundamentally disagree with PG&E's compensation strategy. They dispute that there is any value to ratepayers of PG&E paying above "market" wages. DRA believes that PG&E is paying 8.5% above market parity without demonstrating the benefit to the ratepayers. DRA points out the burden is on PG&E to prove the cost-effectiveness of its above-market pay philosophy. DRA cites a prior PG&E GRC decision which stated:

> "We will not hesitate to make a ratemaking adjustment if the evidence demonstrates that the proposed wage and salary expense of a utility is clearly unreasonable compared to the relative market." (PG&E (1990) 23 CPUC2d at 186.)

In DRA's view the Commission has never adopted or sanctioned PG&E's efficiency wage theory to justify above-market pay. The main thrust of both DRA's and CLECA's argument is that PG&E has not produced any evidence to demonstrate that any benefits which accrue from above-market compensation outweigh its costs. Both parties argue that PG&E has not quantified any benefit which may accrue from paying above market compensation.

DRA suggests that PG&E should have conducted a study comparing its productivity to the companies it surveyed for wages to determine whether (1) increased productivity occurred because of higher pay and (2) if so, how much it increased. Additionally, DRA criticizes PG&E for not comparing its training costs and turnover rates with the other companies included in the surveys in this proceeding. DRA does not enlighten us on how it believes this kind of information could be obtained from unregulated companies. DRA also argues for market average-based pay for ratemaking purposes as a means of utility cost minimization. Both DRA and CLECA argue in their exhibits that the payment of above-market wages cost ratepayers some $85 million in this GRC.

However, we are compelled to note that this figure is listed as $57 million in the Comparison Exhibit, a fact which PG&E (and the ALJ) found confusing. (PG&E Reply Brief, p. 4.) We note that the figure DRA chose to use in its comments on the proposed decision was $55 million.

DRA argues that California utility rates are near the top in the nation. DRA believes that the way to reverse that trend is to discourage excessive utility costs. It thinks that above-market compensation is a good place to apply that effort. Finally, DRA and CLECA both argue that the current recession that California and the nation are experiencing should allow PG&E to select from a larger pool of people. DRA also supports its view on the inappropriateness of PG&E's pay scales based on pay cuts State employees are currently facing in the budget crisis, and in fact have received.

Finally, DRA concludes that if the Commission adopts DRA's disallowance there is no evidence that PG&E's union employees will even be affected. DRA states that some 17,000 of PG&E's employees have a compensation agreement with PG&E through the end of 1993. DRA makes no comment as to what the effect of its recommendation would be on the next round of union negotiations, but seemingly asserts that it should have no impact.

CLECA's position is basically a "me too" argument of DRA's contentions. The witness for CLECA read several articles cited by PG&E and Unions witnesses, which apparently is the extent of her expertise in this area other than once having worked for DRA. In fact, the Unions in their reply brief raise the issue of the competency of both DRA and CLECA witnesses to address the field of compensation at all.

5.3.4 Discussion

We find ourselves once again debating the topic of whether PG&E pays its employees excessively. The last two GRC decisions address this issue and come to unsatisfactory conclusions. The trend has been to go along with PG&E's pay policy but to express discomfort with doing so. Given the showing in this GRC by PG&E and the Unions and the paucity of argument against that showing by DRA and CLECA, we conclude that PG&E's compensation strategy is basically reasonable and that its policy to pay at slightly above market levels is worthy of further consideration.

We conclude that PG&E has met its burden of proof for its compensation policy generally. By definition, it is inevitable that wage surveys, like other surveys have a certain amount of error. Both PG&E, Unions witnesses, and the cited literature agree on a 5% to 10% error rate. We find that a 5% error rate is more reasonable given the record and the economy generally. On this basis, we will lower PG&E's above market compensation strategy down to 5% above market. We note this is still a generous compensation strategy relative to other California utilities. We believe it is an appropriate policy given the record developed in this case. Given the number of the compensation surveys relied on by PG&E, including Mercer, the Bureau of Labor Statistics (BLS), and others, a margin of error closer to 5% is more likely.

We expect PG&E to minimize its costs as much as it can. However, we find PG&E's arguments that its compensation strategy results in a lower turnover rate and accompanying reduction in training costs to be worthy of further study. It is undeniable that PG&E has experienced substantial productivity gains in the past few years. It is undisputed that PG&E has laid off or reduced its work force by some 3,000 workers in the 1980s. It is also undisputed that each worker now handles more customers than previously. PG&E's productivity gains rate very favorably with national standards.

By rejecting DRA and CLECA's arguments in this GRC we are not suggesting that PG&E does not have the obligation to affirmatively prove that its compensation strategy is reasonable in its next GRC. We will order PG&E to continue to refine and improve its analysis of its compensation strategy.

By allowing for ratemaking purposes, a 5% above market compensation strategy, we are not approving at this time particular requests for positions discussed in individual accounts. Whether additional positions are necessary in certain areas is a separate issue from PG&E's overall compensation strategy.

Since Edison's most recent GRC decision ordered a combined compensation and benefit analysis, we will do so here. We order PG&E to present a combined compensation and benefit analyses for all employees in its next GRC (Test Year 1996). We are particularly interested in executive pay and all the accompanying special benefits that may accrue to that group. Likewise, we wish PG&E to further explore the link between its compensation strategy and productivity gains within the company. PG&E should also include an analyses of what impact, if any, our reduction of its compensation levels for ratemaking purposes from 8.5% above market to 5% above market has on actual compensation levels paid to its employees.

We will require that PG&E make the results of the various compensation surveys it relies on available to DRA. This material shall include all applicable benchmarks and job matches, total employee cash contributions for benefit coverage as well as average bonus payments per employee and all other applicable survey materials.

We expect DRA and any other party who pursues this issue in future rate cases, to develop more solid testimony to support their positions. This is perhaps an area where consultants with an expertise in the subject matter at hand are most critical. We hope the additional guidelines on what PG&E must include in its next showing will allow DRA, or its consultants, to develop an independent measure of PG&E's compensation strategy.

## 5.4 Impact on Collective Bargaining of Commission Analysis of PG&E's Compensation Strategy

We cannot leave the area of PG&E's compensation for its employees without addressing the issues raised by the Unions regarding our right to analyze this area. It is not our desire to interfere in the collective bargaining process; rather it is to protect ratepayers from any unreasonably excessive costs of compensation. However, we disagree with Unions that we are legally forbidden from such an evaluation of compensation levels. We agree with DRA that the Commission is not preempted under Federal law from looking into the issue of employee compensation. We endorse DRA's reading of Southwestern Bell Telephone Company v Arkansas Public Service Commission, 824 F2d 672 (8th Cir. 1987). The Southwestern Bell decision clearly rejected the union's preemption argument that the National Labor Relations Act prevents a public utilities commission from adjusting to recover in rates only a portion of the wages and benefits that are the product of collective bargaining.

> "The Arkansas Commission is charged with the responsibility of setting rates that state telephone users will pay and determining a fair rate of return that SWB may earn. As part of this process, the Commission assesses the Company's expenses to determine whether they are reasonable. If the Commission finds that they are not reasonable, an issue controlled by state law standards of arbitrariness and capriciousness, then the Commission will not

> pass them on to consumers in the form of rate increases. We conclude that the Commission's actions disallowing recovery of certain nonmanagement wage and benefit expenses does not rise to the level of an impermissible intrusion into or control over the relationship between the company and CWA. We finally observed, as did the Ninth and First Circuits, that in any regulated industry, myriad governmental decisions, from ratesetting to the imposition of safety standards, undoubtedly will affect labor relations. Any indirect effect of the ratesetting action taken in this case, however, falls short of the kind of state interference with the labor-management relationship that Congress had intended to proscribe." (824 F2d at 676.)

Therefore while this decision does give our Commission authority to look into this area, it is not authority that we choose to exercise without good reason to do so. There has been a showing in this case that PG&E's compensation policy is generally reasonable. We believe our modest reduction to 5% above market pay is a reasonable exercise of our authority.

## 6. Productivity

PG&E complied with Ordering Paragraph 15 from its last GRC decision (34 CPUC2d 199, 439 (1989)). As ordered, PG&E presented in this application a multifactor productivity analysis which PG&E calls a Total Factor Productivity (TFP) analysis.[3] This analysis is based on econometric models which are estimated for PG&E's Electric and Gas Departments. The models' results described the productivity gains embedded in PG&E's Test Year 1993 expense estimates for providing gas, electric, and other energy

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3 Pursuant to an agreement with DRA, the PG&E productivity study includes only the variable factors of production: labor, fuel, and materials. Since the fixed factors are excluded, this approach is described in the economics literature as an analysis of multifactor productivity.

services. The results of PG&E's model show an annual average productivity growth rate of 1.2% for the Electric Department and 1.4% for the Gas Department over the forecast period 1991 to 1993. PG&E points out that these values are comparable to the average annual productivity growth rates experienced in the last decade.

We note that PG&E was the first utility to utilize the multifactor productivity model, which DRA prefers, and continues to be the only energy utility to utilize this methodology. DRA acknowledges PG&E's cooperation by endorsing its productivity study. (RT 14:889.)

In analyzing productivity for the Electric and Gas Departments, PG&E and DRA utilized a common methodology and data base and arrived at very similar results:

| | DRA | PG&E |
|---|---|---|
| | Percent | |
| Electric Department | | |
| 76-90 | 1.3 | 1.5 |
| 91-93 | 1.2; 1.1; 1.2 | 1.4; 1.2; 1.1 |
| | PG&E & DRA | |
| Gas Department | | |
| 76-90 | 1.81 | |
| 91-93 | 2.2; 1.2; 0.9 | |

Indeed, DRA agreed that within the limits of statistical accuracy, PG&E's results and DRA's results are comparable. (RT 14:889.) Likewise, DRA agreed that these estimated productivity gains are fully reflected in the test year estimates.

The TFP analysis is an independent examination of PG&E's historical and projected noncapital-related expenses. This study forecasts PG&E's 1993 Test Year expenses on an aggregate company-wide level. The analysis provides independent supporting evidence for the detailed account-by-account forecast test year expenses which are developed in the various exhibits sponsored by PG&E's witnesses. Therefore, PG&E's productivity results are appropriately used as independent verification of the test year estimates of nonfuel expenses and the productivity gains that are contained in these estimates. For example, using DRA's productivity model, a forecast was made of nonfuel operations and maintenance expenses of $1,917,821,000. At the time of DRA's original report, the Energy Cost Branch of DRA forecasted electric nonfuel operations and maintenance expenses of $1,688,221,000 or $229.6 million below the productivity model estimate. (Exhibit 106, p. 2.) DRA's productivity witness agreed that if the results of operations estimates are below the productivity model's projections for the test year, the results of operations include a productivity component which is equal to or greater than the productivity estimated by the model, and that this would be a fair characterization of the econometric results compared to the results of operations estimates. (RT 14:891-892.)

For this reason, neither PG&E nor DRA recommends any further productivity adjustment because all productivity gains in the test year are currently being allocated to ratepayers. (RT 12:577.) According to PG&E's productivity witness, Ansar, to the extent that these gains, reflected in lower test year estimates of expenses, are carried forward into the years 1994 and 1995, the implicit assumption appears to be that productivity will offset the increases in scope and quality that the utility faces in the attrition years. (RT 12:580.)

In addition, PG&E witness Ansar went on to explain that increasing productivity does not necessarily mean that every cost input will be minimized to the same extent. In fact, she argued that there may be certain increases of certain cost inputs if they are valuable in order to increase productivity:

> "If I may, I, as an illustration of that very point, if I may just tell a short story, if you will.
>
> "In 1914, the Ford Motor Company announced that it would give its workers a wage increase, an increased wage from $2.50 to $5.00 per day.
>
> "The going wage at other plants in Detroit remain at $2.50 for several years.
>
> "The day following the $5.00 wage announcement there were 10,000 people lined up outside Ford's Highland Park plant, all of them eager for jobs.
>
> "And over the next few months thousands more flocked into Detroit searching for jobs at Ford. Of course the question is why in the face of a sizeable excess supply of labor did Ford not lower its wage until the market cleared.

> "Within the plant the wage increase have the effect of disciplining the workers, knowing that they can immediately be replaced and that jobs those days were hard to find, Ford workers basically did what they could to ensure that they would not lose their jobs.
>
> "They worked more diligently, more productively, they worked at a faster pace and they also responded with what some people have called unquestioning obedience to managerial authority.
>
> "Years later Henry Ford was actually to remark the payment of $5.00 a day was one of the finest cost-cutting moves he ever made." (RT 12:578, 579.)

We agree with both DRA's and PG&E's analyses that PG&E has continued to experience productivity gains. Because the numbers of the two econometric models are so close, and the results are virtually the same, we will adopt PG&E's modeling figures for productivity. We note that the Henry Ford story adds some credibility to the notion that PG&E's previously discussed compensation policies are a factor in the ever-increasing productivity of the company's workers.

We will discuss the issue of the sharing of productivity gains in attrition years as proposed by the DRA later in this decision in the section on Attrition.

Finally, we agree with the parties that productivity gains have already been embedded in the Test Year 1993 numbers. Therefore, the ratepayers reap the benefits of all productivity gains for the Test Year 1993.

## 7. Escalation

Since estimates of test year expenses are developed from 1990 constant dollars, it is necessary to accurately account for the effects of inflation on PG&E's expenses between 1990 and 1993. PG&E's method of accounting for inflation for labor as well as materials and services expenses is similar to the practice adopted

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We will discuss the issue of the sharing of productivity gains in attrition years as proposed by the DRA later in this decision in the section on Attrition.

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## 7. Escalation

Since estimates of test year expenses are developed from 1990 constant dollars, it is necessary to accurately account for the effects of inflation on PG&E's expenses between 1990 and 1993. PG&E's method of accounting for inflation for labor as well as materials and services expenses is similar to the practice adopted by the Commission in previous GRCs, including PG&E's 1990 GRC. (Exhibit 5.)

As has been discussed already, the primary difference between PG&E's and DRA's recommendations for labor escalation is that DRA recommends zero escalation for labor as a penalty for noncompliance with the last GRC decision. We have already rejected DRA's position. There are other smaller differences between DRA's position and PG&E's position for other price change effects.

## 7.1 Labor Escalation

DRA did recommend alternate escalation factors in the event that its zero escalation recommendation was rejected. These escalation factors were based on the International Brotherhood of Electric Workers (IBEW) contract rates less the influence of PIP participation rate for the 1990 labor contracts. PG&E contends that PIP's impact on the escalation rate is 0.5% per year. Thus, PG&E's recommended labor escalation rates are as follows: 4.25% for 1991, 4.50% for 1992, and 5.00% for 1993. (Exhibit 5, pp. 5-5 and 5-8.)

DRA's recommended alternative escalation rates are one-half percentage point lower than PG&E's rates. (Exhibit 102.) PG&E argues that DRA provides no rationale for excluding the PIP participation through its labor escalation witness. As we will cover in the discussion on PIP generally, we agree with PG&E's analysis of this issue.

PG&E and DRA agree that the attrition year forecasts of the Consumer Price Index-Workers (CPI-W) should be updated and the forecasts are expected to be agreed upon at that time. Therefore, the numbers from the September 15 Update hearing for CPI-W presented by PG&E shall be adopted.

There are some other impacts on the test year labor escalation recommendations that should be discussed here. There is a $7 million difference between PG&E's and DRA's position as it applies to contested labor base estimates stemming from different recommended activities level in the various expense accounts. The effect of DRA's alternate labor escalation recommendation to exclude PIP-related escalation is $8 million on uncontested base labor amounts and $1 million on the contested base labor amounts.

For the Gas Department, the final remaining difference between PG&E and DRA concerns over $4 million in the test year due to the impact of DRA's alternate labor escalation proposal to exclude PIP-related escalation. The final outcome of these differences will be decided in later sections of this decision.

## 7.2 Nonlabor Escalation

For nonlabor escalation, DRA has indicated that it fundamentally accepts the methodology employed by PG&E to develop its materials and service index (MSI), but recommends that all cost elements not appropriate to the nonlabor escalation base be removed from the calculation. While agreement was reached on some of these issues at hearing, and the Comparison Exhibit still indicated some different M&S escalation rates for PG&E and DRA, these differences were resolved in the September 1, 1992 Update. (Exhibit 237, p. 2B-1.) DRA had no questions for PG&E's escalation witness during the Update hearings. Exhibit 237 shows the following nonlabor escalation rates:

1991 - 3.15%
1992 - 2.74%
1993 - 3.74%
1994 - 3.73%
1995 - 3.54%.

These numbers include the weighted factors agreed to by PG&E and DRA.

Finally, medical escalation differences exist between PG&E and DRA. DRA uses 1991 recorded data to estimate 1993 expenses in 1993 dollars. PG&E's estimates for medical costs are given in 1990 dollars which must then be escalated at the rate shown in the Comparison Exhibit. (Exhibit 235.) Fundamentally, this difference is due to disagreements over medical costs which will be discussed in connection with Account 926 in Administrative and General Expenses.

## 8. Results of Operations for Electric Department-Operations and Maintenance (O&M) Expenses

### 8.1 Overview

Both PG&E and DRA have prepared complete estimates of PG&E's results of operations for 1993.

Throughout this decision we shall discuss the Electric Department first and in greater detail since it is the larger portion of PG&E's overall operation. Additionally, issues which are common to both gas and electric will be discussed in detail here.

PG&E's electric operation and maintenance (O&M) expenses fall into three categories: production expenses, transmission expenses, and distribution expenses.

Electric production includes nuclear generation (excluding Diablo Canyon), fossil and other generation, and hydraulic power generation. PG&E's nuclear generation expense estimate is for expenses associated with its Humboldt Bay Power Plant Unit No. 3. PG&E's fossil generation includes all of PG&E's gas- and oil-fired steam generation units and all of its geothermal units. Other generation includes PG&E's gas turbine units and fixed bond payments and maintenance and operating expense paid to various irrigation districts. PG&E's conventional fossil-fired generation units consist of 33 units with a net operating capacity of 7,213,000 kilowatts (kW). These units have an average age greater than 34 years.

PG&E's hydraulic power generation consists of 111 conventional hydraulic generating units and three pumped storage units with a total net operating capacity of 3,903,000 kW.

PG&E's estimate of $290,495,000 for electric production expenses was reduced by DRA based on disallowances of $24,325,000. For nuclear production expenses, the PG&E estimate of $1,254,000 was found reasonable by DRA.

In fossil and other production, PG&E's estimate was reduced by DRA by approximately $20 million. Of this amount, $15 million is due to estimating methodologies, and $4.8 million is in programs. Most of this program difference relates to the areas of major plant maintenance items or asbestos removal work.

In other production, DRA recommends a disallowance of $68,000. This difference is entirely due to estimating methodologies.

In hydraulic production, DRA recommends a reduction of PG&E's estimate of $4.1 million. Roughly $2.2 million of this disagreement is due to estimating methodology and nearly $2 million is due to disagreements over programs. DRA does not believe PG&E should recover all of its proposed expenses associated with an on-line hydro maintenance system (OHMS), vegetation control, or Federal Energy Regulatory Commission (FERC) fees.

PG&E's electric transmission expenses include substation structures, substation equipment, poles, towers, conductors, underground line equipment, and miscellaneous plant operated at 50 kilovolts (kV) and above. PG&E's estimate of $65,523,000 for electric transmission expenses was reduced by DRA by $2,060,000. The principal areas of disagreement between PG&E and DRA are in estimates of electric and magnetic field (EMF) expenses, Power Control staffing levels, tree trimming and removal expenses, and estimating methodologies.

PG&E's electric distribution expense estimate of $256,677,000 was reduced by DRA by $11,601,000. The parties disagree in EMF support and customer response expenses, training for supervisory control and data acquisition (SCADA) system, and distribution automation, strategic technology support expense, cable elbow replacement accounting, tree trimming and removal expenses, and estimating methodologies.

We have mentioned several times the differences in estimating methodologies used by PG&E and DRA. This refers to the different procedures the parties have used to forecast the reasonable cost to PG&E of providing and maintaining a reasonable level of service in 1993. These estimates are done on a painstakingly tedious account-by-account basis. For each account, PG&E has forecast the expected level of work or activity in that account in the Test Year 1993. For each account PG&E began with the base estimate and then adjusted the base estimate to reflect changes in the account activity expected in the test year. In most cases, PG&E used as its base estimate the actual recorded expenses for the last recorded year or a five-year average, three-year average, or some other combination. In certain instances, DRA chose to use a different methodology for making these estimates. For example, in a situation where DRA chose to make a three-year average PG&E may have used a last recorded year base estimate. Of course, to obtain Test Year 1993 numbers, these base year estimates are then escalated by the labor and nonlabor escalation factors discussed in the prior section. As ordered by the ALJ, PG&E and DRA prepared an account-by-account summary of methods used to estimate expenses. This account-by-account trending method summary appears as Appendix A to the Comparison Exhibit (Exhibit 235). As that appendix shows, for the vast majority of accounts PG&E and DRA agreed on the methodology. In fact, for many accounts there was no dispute as to the expense estimate for Test Year 1993. However, there are many accounts where there is disagreement either as to methodology or as to programs included in the accounts. We have not yet come up with a way to discuss these disputes without an account-by-account analysis in the GRC. The reader is encouraged to bear with us as we proceed into the world of individual account analysis.

**8.2 Nuclear Production Expenses**

The only O&M expenses associated with nuclear production in this GRC are for the Humboldt Bay Unit 3 plant. Humboldt Bay Unit 3 is in the process of being decommissioned. Prior to the final dismantlement and decontamination of the plant, O&M expenses will include the costs of monitoring and surveillance activities as well as maintenance of the security systems required by the Nuclear Regulatory Commission.

In its opening brief, DRA states that it agrees with the estimates PG&E has proposed for materials and services (M&S) but disagrees with the 3% increase PG&E has requested as part of its PIP. DRA points to its Exhibit 107 on Total Cash Compensation for an explanation on the PIP disallowance in this account. However on reviewing that exhibit we find no such justification. We will therefore adopt PG&E's nuclear production expense estimate already set forth of $1,256,000.

**8.3 Fossil Fuel Production Expenses**

In order to calculate the fossil fuel and other production expense estimates for each account, both PG&E and DRA chose a base estimate as we discussed above. That base estimate, derived either from the expenses recorded in 1990 or an average of the last two to five years of recorded expenses, was then adjusted to allow for inflation or unusual events.

According to PG&E witness Czabaranek, an average of the last five recorded years would be used where the expenses in an account "fluctuated," i.e., increased and decreased over the five-year period. (RT 15:942.) PG&E states that where changes in the accounting system used by PG&E had affected the expenses in an account midway through the five-year period, an average of the last two or three years of recorded expenses would be used instead. If an account had shown a continuous trend in one direction or another, PG&E used the last recorded year, 1990, for its base estimate.

Generally, DRA used similar guidelines for calculating base estimates. In DRA's opinion, due to improvements in the fossil and other power production operations, it relied more often than did PG&E on the 1990 recorded expense levels as most likely to reflect those recent developments. (Exhibit 103, p. 4-B-2.) We will now proceed to discuss individually each account where there is a dispute between PG&E and DRA. Where DRA did not dispute PG&E's numbers, we will adopt PG&E's proposal. There is no need to discuss the undisputed accounts. We note that only seven accounts are in dispute in this section under fossil fuel generation. For the ease of the reader we will list each account both by its CPUC account number and its PG&E account number.

8.3.1 CPUC Account 505 (PG&E Account 764): Electric Expenses

PG&E recommends an estimate of $31,969,000 for this account while DRA recommends $25,956,000 for this account for Test Year 1993. This account includes the expenses associated with the operation of prime movers, generators, and auxiliary equipment.

During hearings, PG&E did accept a reduction of $194,000 for condensate reroute as recommended by DRA (RT 15:946.) This condensate reroute is due to a PG&E project to route the condensate from one Geyser geothermal unit to abate the high concentration of hydrogen sulfide in another.

For this account PG&E chose to average labor expenses over the last four recorded years and average material and services over the last three recorded years. DRA chose to use recorded 1990 data for both labor and material and services in this account.

PG&E justifies its methodology by its position that decreases in this account over the last four years were related to decreasing chemical and waste costs at the Geysers powerplants. PG&E contends that these decreases due to installation of incinerators to burn off gases and upgrades to secondary abatement systems are the result of major projects to reduce chemical expenses which have now been completed. PG&E expects expenses to rise in the future as a result of an increasing volume of gas being released from the steam fields due to variable pressure operation and increasing disposal costs. (RT 15:998.)

On the other hand, DRA witness Han argues that the appropriate base year is 1990, given the steady decline in expenses. DRA believes a continuing decline in labor expenses is due to the retirements and cold standby status of several Geysers units. The DRA witness does not expect any increases in this account in the future. (RT 16:1084.) DRA points out that PG&E's own stated policy is to use the last recorded year as a base estimate when there has been a steady decline.

We are persuaded by DRA's argument on this issue. PG&E did not make an adequate showing that increasing expenses should be expected in the future in this account. Therefore we adopt DRA's estimate of $25,956,000 for CPUC Account 505.

### 8.3.2 CPUC Account 506 (PG&E Account 765): Miscellaneous Steam Power Expenses

This account deals with the expenses that are not assignable to other steam generation accounts. PG&E recommends $24,602,000 while DRA advocates $24,059,000 attributable to this account. The difference of $543,000 is due to the estimating methodology used by both parties. PG&E associated the 1986-87 decline in labor expense with unit retirements, and therefore believes a four-year average is the correct methodology. PG&E points out that the labor portion of this account had dropped two out of five years in its estimate. (RT 15:946.) On the other hand, DRA used the 1990 recorded figures to calculate labor expenses. DRA believes it is reasonable to use the 1990 recorded numbers because the labor expenses associated with this account will continue to decrease due to the retirements and placement on cold standby status of several Geysers units. (Exhibit 103.)

We concur with DRA on this issue, believing that it is more likely that labor expenses will continue to decline for this account. We adopt DRA's figure of $24,059,000 for Account 506.

<u>8.3.3 CPUC Account 511 (PG&E Account 441): Structures</u>

Account 511 includes the expenses associated with the maintenance of steam plant structures. PG&E estimates $2,579,000 for Test Year 1993 while DRA estimates $1,153,000. The difference is due to the estimating methodology used by each party.

PG&E used recorded 1990 figures for both the M&S portion and the labor portion for this account. PG&E's witness testified that an accounting change in 1988 is one of the reasons for a steady increase in expense in this account. That accounting change moved the responsibility of structure maintenance to the facilities themselves. PG&E argues that it is reasonable that facility operators can most efficiently identify and accomplish needed structural maintenance. Further, PG&E contends that it is unreasonable to expect activities to decline in the future given the age and the harsh environment within and around powerplant structures.

On the other hand, DRA used a five-year average to calculate labor and material expenses. DRA points out that in that five-year period there was a decrease from $743,000 in 1987 to $310,000 in 1988. (RT 15:949.) DRA notes that the account booked a substantial increase from $809,000 in 1989 to $2,670,000 in 1990. Given these fluctuations, DRA believes it would be inappropriate to use the 1990 recorded expenses for this account. DRA points out that jobs construction maintenance tends to vary substantially in price and scope from year to year. (Exhibit 103, p. 4-B-12.)

Given the evidence presented, we agree with DRA that a more appropriate approach for this account is to base the expenses on a five-year average.

### 8.3.4 CPUC Account 512.2 (PG&E Account 442): Boilers and Related Apparatus

This account includes the expenses associated with the maintenance of boilers and their related apparatus such as furnaces, super heaters, and reheaters. In addition, this account contains monies for asbestos mitigation programs. PG&E plants used insulating materials in the past which contained asbestos. PG&E's total estimate for this account is $22,735,000. DRA's estimate is $21,681,000, or a difference of $1,054,000. DRA disagrees both with PG&E's estimating methodology and the total dollars requested for the asbestos mitigation or removal program.

As to its estimating methodology, PG&E used an average of the last two years for its labor estimate and an average of five years for materials and services expenses. DRA chose to use the expenses for the last recorded year, 1990. PG&E argues that this is inappropriate because this account has shown an increasing trend over the years. However, we note that an increasing trend rather than fluctuation is generally considered a basis for selecting last recorded year expenses. PG&E's apparent problem with the DRA choice of methodology is that the account would be reduced by $634,000 from PG&E's own estimate. The fact that an account would be lower or higher given a certain methodology is not the basis for our selection of the methodology in a particular account. We find that PG&E has inadequately justified its request for a two- and five-year average in this account and will therefore adopt DRA's recommendation of using last recorded year expense data. This results in the reduction of this account for methodological reasons of $634,000.

In addition, DRA seeks to reduce the amount of the asbestos removal program for Test Year 1993 by $420,000. PG&E's witness explained that asbestos is currently removed from areas within powerplants identified as high exposure areas (i.e., areas of considerable human activity or significant movement near plant boundaries). For example, PG&E has already removed considerable asbestos from the Moss Landing powerplant and will continue to do so into Test Year 1993. In 1991 and 1992 the expenditures for Moss Landing powerplant alone are approximately $1.7 million. PG&E argues that additional work at Moss Landing in 1993 could approach a level of $2.4 million. PG&E contends that reducing this amount would delay or extend the asbestos removal program.

DRA notes and PG&E concurs that at this time removal of asbestos from Moss Landing or any other powerplant is strictly voluntary for PG&E, under no mandate by federal or state law. (RT 15:959.) PG&E's witness claimed that certain areas of the Moss Landing plant would not have asbestos removed by the end of 1992 but was unable to designate any specific areas.

We agree with DRA's estimate for Account 512.2. DRA's estimating methodology is more reasonable as we already stated. In addition we concur with DRA that a certain portion of PG&E's asbestos mitigation program is appropriate to remove from this account. While we applaud PG&E for its overall asbestos program, we must weigh the costs to the ratepayers of moving ahead with these programs when they are voluntary and accelerated in nature. Obviously, PG&E shareholders are free to make the decision to move ahead with mitigation programs prior to their being mandated by federal or state law.

### 8.3.5 CPUC Account 512.3 (PG&E Account 443): Boiler Plant Auxiliaries

This account includes the expenses associated with the maintenance of boiler plant auxiliaries such as feed water systems, cranes, and other instruments and devices. PG&E estimates $17,233,000 for this account while DRA estimates only $13,316,000. The total difference between the two parties is $3,917,000, $210,000 of which relates to asbestos removal with the balance of $3,707,000 relating to differences in the estimating methodology. In this account, the difference in the estimating methodology is a substantial one. PG&E used the last recorded year, 1990, for its estimate. DRA, on the other hand, used the average of the last five years. DRA disagrees with PG&E's use of 1990 expenses as the base estimate because 1990's expenses were roughly $3 million larger than any other year. DRA found PG&E's reasons for this difference to be vague and unpersuasive. DRA correctly points out that the PG&E witness was somewhat vague as to the reasons for this increase during the opening round of hearings, or PG&E's initial showing. (RT 15:961.) Some of the reasons for the 1990 "blimp" in expenses were due to increased salinity in river water use for the powerplants, increased asbestos maintenance, and the cost of city water. Therefore DRA argues that using the five-year average is a more reasonable estimate due to this large and largely unexplained increase in expenses between 1989 and 1990. In addition, DRA believes it is appropriate to reduce by $210,000 the amount of expenses PG&E sought to apply to voluntary asbestos removal for the same arguments discussed for Account 512.2.

PG&E argues that last recorded year is more appropriate for this account as a reasonable estimate for 1993 expenses. In its rebuttal testimony, PG&E set forth that this account had already been reduced in its 1990 recorded year data for the unusually high amount of asbestos maintenance and removal that occurred in that year. PG&E admits to a closer review being made of this account in its rebuttal testimony. (Exhibit 221, p. 4-2.) This closer review indicates that the increase primarily relates to asbestos-related activities. While there are some reference to Occupational Safety and Health Administration (OSHA) regulations being part of the reasons for the increased asbestos activity, PG&E has not made an affirmative showing to indicate that this level of asbestos work in this time frame is mandated by any state or federal laws.

We agree with DRA that a change of this magnitude should have been explained more thoroughly in PG&E's opening showing in the case. We find the arguments raised in its rebuttal testimony to be unpersuasive to compel us to use the 1990 recorded year. We believe the five-year average as proposed by DRA gives a more accurate and realistic reflection of what the account expenses will be in Test Year 1993.

### 8.3.6 CPUC Account 512.4 (PG&E Account 444): Main Turbo-Generators and Related Apparatus

This account includes the expenses associated with the maintenance of main turbo-generators such as throttle and inlet valves, pressure oil, and steam pipings. Expenses in this account also include the adjustments for nonroutine maintenance, the retirements of Geysers units, and the reliability improvement program for the Geysers powerplants. Also included and of controversy between the parties is the turbine blade replacement program.

PG&E is requesting $32,217,000 for this account while DRA estimates $27,631,000. In this instance the methodological difference is only $621,000. The $3,965,000 disparity is due to the turbine blade replacement program. We note that while the turbine blade replacement program was discussed during hearings, DRA chose not to mention it in its briefs. PG&E used a three-year average for the labor portion of this account and a five-year average for the M&S portion. PG&E justified its three-year average for labor based on the decrease from 1986 to 1987 and then again from 1987 to 1988 as a result of unit retirements. PG&E believes a five-year average for M&S is appropriate to reflect the fluctuating nature of the past expenses. In contrast, DRA used 1990 recorded figures for both labor and M&S expenses because of the declining trend in both portions. DRA believes that the declining trend is a result of the retirements and cold standby status of some units as well as the installation of improved diagnostic instruments and in-plant performance monitoring devices. In DRA's opinion, this declining trend should continue into the test year. (Exhibit 103, pp. 4-B-13 through 4-B-14.)

We agree with DRA as to both prongs of its positions for this account, and will therefore reduce this account by $4.586 million per DRA's recommendation.

### 8.3.7 CPUC Account 513.5 (PG&E Account 445): Main Turbo-Generator Auxiliaries

This account includes the expenses associated with the maintenance of electric plant auxiliaries such as condensers, condensate, pumps, air and vacuum pumps, vacuum breakers, and pooling systems. (Exhibit 103, p. 4-B-14.) PG&E requests a total of $15,829,000 for this account, while DRA recommends $13,259,000.

The difference of $2,570,000 is divided as follows: $210,000 due to a difference in asbestos removal projects and $2,360,000 due to methodological differences.

As to the methodological differences, PG&E chose to use five-year averages for both the labor and M&S portions of the account. PG&E does not dispute that there has been a steady decline in labor expenses every year since 1987 in this account. Because of this, DRA argues that use of 1990 recorded expenses is more appropriate for the Test Year 1993 estimates. DRA attributes the decreases to retirements and cold standby status of some units and improvements in the diagnostic instruments that monitor plant performance. On the other hand, PG&E claims that expenses are expected to increase in these areas, because most projects benefitting maintenance and operating expense have already been completed.

As to the reduction in asbestos mitigation expense, the parties make the same arguments that have been previously discussed.

Once again we agree with DRA as to this account. We believe the 1990 recorded expenses are a more appropriate and accurate base for Test Year 1993 due to the declining trend that this account has shown. Likewise, we will follow DRA's recommendation as to the asbestos mitigation expenses being disallowed. Once again we note that our disallowance of some asbestos mitigation expenses does not mean that PG&E's asbestos mitigation programs will not proceed. It simply means that it may or may not be necessary that the programs proceed at the pace which PG&E has recommended in this rate case.

### 8.4 Hydro Production Expenses

For hydro production the main program or activities differences between DRA and PG&E are roughly $2.5 million which relate to the OHMS project (an automated computerized work management system), FERC administrative fees, and vegetation control. As to the methodological differences between DRA and PG&E, the major difference is due to the position on weather conditions as a factor. PG&E and DRA fundamentally disagree on whether the weather after 1986 was abnormally mild. DRA suggests that 1986 was an abnormal year but the years following that had normal weather. (RT 16:1115.)

8.4.1 CPUC Account 535 (PG&E Account 780): Operations, Supervision, and Engineering

This account includes the expenses associated with general supervision and engineering for operation of the hydraulic power generating stations. PG&E recommends an amount of $2,243,000 for this account. DRA suggests an estimate of $1,750,000. The difference of $493,000 is due mainly to a DRA disallowance of OHMS costs. The methodological difference is only $20,000.

Both PG&E and DRA used 1990 recorded data for the base estimates of M&S expenses. For labor expenses DRA used last recorded year while PG&E used an average of three years. DRA believes it is more appropriate to use 1990 recorded figures in order to capture the savings associated with the installation and operation of the OHMS. PG&E describes this as a computer automated work management system, which integrates operational performance, equipment records and history, accounting and materials stock status. PG&E projects full implementation by the end of 1995. DRA justifies its disallowance for the OHMS work in 1993 because in its opinion PG&E has failed to show the productivity gains and savings that this program was promised to produce. PG&E's own witness testified to productivity gains and savings that should be apparent at least in the southern area in 1991. PG&E disagrees with DRA on this point, arguing that DRA's disallowance is inconsistent with the notion of encouraging productivity and efficient use of resources. PG&E argues that much of the savings from OHMS will be in the scheduling of maintenance activities during and between outages plus reducing outage time and increasing hydro energy output. PG&E concludes that this will reduce fossil energy need and be reflected in the ECAC as reduced fuel expenses. (RT 13:1002.) PG&E argues that while not quantified, productivity will also improve beyond the test year as a result of this system, and ratepayers will benefit in future years.

We agree with DRA that promised productivity gains should have been somehow quantified to justify additional expenditures in this area. Therefore we adopt DRA's recommendations for CPUC Account 535.

8.4.2 CPUC Account 536 (PG&E Account 781): Water for Power

This account includes payments for the purchase of water for power. PG&E recommends $3,356,000 for this account. DRA's recommendation is $350,000 less, equalling a total of $3,600,000 for this account. The difference is due to a difference in methodology. PG&E used the five-year average for labor and M&S expenses while DRA believed a three-year average was more appropriate. The differences in the averages focus on whether the year 1986 should or should not be included. DRA believes 1986 should be excluded because unusually high expenses were associated with this account as a result of levy damage and flooding in 1986. DRA points to the testimony of the PG&E witness who argued that the storms of 1986 inflicted heavy damage to many hydro facilities, and that every year since 1986 has been characterized by mild weather. (RT 15:979.) PG&E relies on the same facts as to weather conditions from 1986 onward to conclude that a five-year average is more appropriate. PG&E points out its belief that the mild weather experienced since 1986 is not "normal."

We agree with PG&E on this issue. The mild weather that has occurred since 1987 is hopefully not going to continue indefinitely. Therefore we believe it more reasonable to include as one of the five years of experience a year with heavy rainfall. We note if the years since 1986 had been "normal weather" we would be more inclined to agree with DRA's position. However, that not being the case, we will adopt PG&E's estimate of $3,356,000 for Account 536.

8.4.3 CPUC Account 537.1 (PG&E Account 782): Hydraulic Expenses

This account covers the costs of operating hydraulics works, including reservoirs, dams, and waterways. PG&E believes that this account is weather-dependent and that the level of expense required for debris removal, vegetation control, and helicopter patrol is weather-dependent. (RT 15:980.) PG&E recommends a total estimate for this account of $3,609,000 while DRA recommends a reduction to $3,451,000. The difference of $158,000 is due to two factors. First, a methodological difference of $110,000 and second, a difference of $48,000 for a vegetation control employee position. For this account, both PG&E and DRA used a five-year average for the labor portion. As to the M&S portion, DRA used a three-year average while PG&E used the five-year average. DRA believes a three-year average for M&S is more appropriate to reflect the "relatively flat" level of these expenses since 1988. (RT 15:981.) However, on cross-examination the PG&E witness did point to a slight increase from 1988 to 1989 in the account. This increase would qualify this account for longer averaging under the fluctuation theory that we have used for other accounts. However, PG&E's witness does state that it is a relatively flat fluctuation. DRA does not overtly dispute PG&E's claim that this account is weather-dependent and that debris removal is associated with the costs of vegetation control and helicopter patrol.

As to PG&E's request that three additional employees be funded to work in vegetation control, DRA believes that only two such positions should be funded. PG&E argues that the need for three new employees is because its system is divided into three different areas. However, PG&E could not say whether these positions in each area were full time. PG&E did state its plan is to contract out the work. Since PG&E could offer no evidence as to whether the three positions were indeed full time, DRA recommends only two workers be approved. We agree with DRA as to the employees for vegetation control and will only allow ratepayer funding of two positions. Therefore in this account we have agreed with PG&E as to its methodological position and agreed with DRA as to reducing the vegetation control employee position. Therefore we will approve an amount of $3,561,000 for Account 537.1.

8.4.4 CPUC Account 538 (PG&E Account 783): Electric Expenses

This account includes the expenses associated with the generation of prime movers, generators, and their auxiliaries. PG&E requests an estimate for Test Year 1993 of $6,039,000. DRA recommends $5,668,000, reflecting a reduction of $372,000 due to a difference in its estimating methodology. DRA used last recorded year 1990 estimates for both labor and materials and services. PG&E, on the other hand, used last recorded year for materials and services but used a five-year average for labor. PG&E justifies its five-year average methodology by pointing to fluctuations in this account, showing a decrease from 1986 to 1987, an increase from 1987 to 1988, and a larger decrease from 1989 to 1990. However, the PG&E witness did testify that generally for 8 out of 12 months lower charges were experienced in this account. The witness could give "no real particular reason for it." The witness went on to speculate that "I would probably account to our abilities to move expenses around from one account to another where we may focus more attention in one area in one year and then another area in another year." (RT 15:983.)

DRA believes that the 1990 recorded expenses for labor more accurately forecast the expenses in this account in 1993 by recognizing the declining trend since 1988. We are not persuaded by PG&E's argument for the five-year average for labor for this account. Therefore we will adopt DRA's last recorded year numbers for both materials and services and labor for Account 538.

Therefore this account will show a Test Year 1993 estimate of $5,668,000.

8.4.5 CPUC Account 539 (PG&E Account 784): Miscellaneous Hydraulic Power Generation Expenses

This account includes costs for labor, materials, and other expenses not assignable to other hydraulic generation operation expense. Included among these expenses are fees associated with water use and hazardous waste regulation and FERC fees. PG&E requests $5,511,000 for this account, while DRA recommends $4,687,000. The methodological difference accounts for $95,000 while a dispute over the amount of FERC fees for 1993 accounts for $729,000. Thus the total disagreement over this account between PG&E and DRA is $824,000. We will address the methodological difference first.

PG&E used a five-year average for labor and a two-year average for materials and services to develop the Test Year 1993 estimate. DRA used recorded 1990 expenses for both. DRA believes 1990 recorded year figures are more accurate for both labor and materials and services to reflect the recent changes in the regulatory fee structures and in regulation in general. PG&E disputes DRA's use of 1990 recorded data on the grounds that despite mild weather experienced for the past several years, fees could increase during normal weather conditions. We agree with DRA that changes have occurred and there is a declining trend in this account. Therefore, we will adopt DRA's estimating methodology of last recorded year for both portions of this account.

As to the dispute over the appropriate amount of FERC fees to allow for this account, PG&E's estimate is substantially higher than DRA's. PG&E is recommending a method whereby an average percentage increase for FERC fees since 1986 is added on to the 1990 recorded figure. Then PG&E applies an M&S escalation factor. DRA believes that this method effectively escalates the FERC fees twice. DRA believes it would be more appropriate to base them on 1990 recorded expense multiplied by the materials and services escalation rate. (Exhibit 103, p. 4C-5.) DRA notes that from 1988 through 1990 the fees paid by PG&E to FERC remained relatively constant. DRA attributes the increase in FERC fees experienced in 1991 to things not expected to occur in Test Year 1993. PG&E cautions that in the event that 1993 returns to normal year condition, there will be an increase in hydro fees to FERC along with the increase in hydroelectric production generally.

Given the trends in this account, we are inclined to adopt DRA's estimates. PG&E has not made enough of a showing to convince us that the FERC fees will actually increase in 1993. We note that by using 1990 as a base year we are giving PG&E a fairly generous estimate of FERC fees in comparison to prior years. Therefore, we will adopt a figure of $4,687,000, per DRA's recommendation, for Account 539.

### 8.4.6 CPUC Account 541 (PG&E Account 460): Maintenance Supervision and Engineering

This account includes the expenses associated with the general supervision and engineering for the maintenance of hydraulic-powered generating stations. Both PG&E and DRA used recorded data from 1990 as the base estimate for both labor and M&S expenses.

Therefore, the only remaining difference in this account is due once again to the OHMS system, resulting in an adjustment by DRA of $20,000. We note that PG&E made no mention of this account or the disagreement in its opening brief. However in its reply brief it seems to dispute DRA's recommendation. The reasoning behind our decision in this account is the same as that set forth for CPUC Account 535 where we first discuss the OHMS system. Once again, DRA believes the productivity gains PG&E claims will result from the implementation of OHMS should produce savings at least equal to the additional costs of completing OHMS. Therefore DRA justifies its disallowance of new increases in OHMS expenses and suggests that the approved expenses remain at the 1990 level. We concur with DRA on this issue and therefore will reduce this account by $20,000.

8.4.7 CPUC Account 545.5 (PG&E Account 465): Miscellaneous Hydraulic Plant

This account includes the expenses associated with the maintenance of miscellaneous hydraulic generation plant facilities.

PG&E originally requested $2,413,000 for this account. DRA's recommendation is only $655,000. PG&E has agreed to delete $576,000 from its request due to the Electra Powerhouse cleanup. (PG&E opening brief p. 95.) The remaining difference of $1,182,000 is due to differences in estimating methodology. This fairly substantial difference between the parties is due to the fact that PG&E used recorded 1990 as its base estimate for both labor and materials and services while DRA used the five-year average. DRA justifies its choice by pointing out that a five-year average mitigates the effects of an increase in materials expenses that was five times in 1990 what it had been in 1989 and labor expenses that were almost four times higher in 1990 than in previous years. (Tr. 15:990-991.) Thus, DRA believes a five-year average best reflects the actual expenses likely to occur in the test year given such a dramatic "blimp" in the recorded data.

PG&E points out the majority of the increase in 1990 was due to hazardous waste activities. PG&E claims it reduced the 1990 amount by a $100,000 for Test Year 1993. PG&E believes this account is trending upward and suggests to us that the increasing stringency of environmental requirements and PG&E's commitment to conducting its business in an environmentally sensitive matter will result in this 1990 trend continuing upward.

While we applaud PG&E's commitment to be environmentally sensitive, we note that our usual handling of accounts with such dramatic increases in a particular year is to average rather than use 1990 recorded year data. We also note that PG&E did not give adequate, specific explanations as to why this account will continue in the upward trend given the size of the dollars. Because PG&E failed to make a complete affirmative showing, we adopt DRA's number for Account 545.5 of $655,000.

8.4.8 CPUC Account 545.7 (PG&E Account 467): Fish and Wildlife Facilities

This account includes the costs of labor and expenses incurred in the maintenance of fish and wildlife facilities. PG&E used a five-year average as its base estimate for both labor and M&S expenses, while DRA used a three-year estimate for both. DRA believes its estimate is more appropriate since there has been a decline in materials and services expenses since 1988. Once again we note that PG&E chose not to mention this account in its opening brief, leading one to the conclusion that it had agreed with DRA's position. However, in its reply brief, PG&E did address this account, once again stating that because there had been fluctuations during the five-year period the five-year estimate is more appropriate.

We find PG&E's argument unpersuasive and will adopt DRA's estimate for Account 545.7.

8.4.9 CPUC Account 548.8 (PG&E Account 468): Recreation Facilities

This account includes the expenses associated with maintaining public recreation facilities. PG&E used a five-year average for its base estimates of labor and M&S expenses. DRA believes the use of a three-year average for both portions is more appropriate due to the declining trend in this account. While PG&E did not address this account in its opening brief, it did in its reply brief and testimony point out that this account like others that have been discussed, is weather-dependent. PG&E also suggests that M&S has not shown a declining trend but rather increased in 1988 and 1989. In order to be consistent with other accounts that are weather-dependent, we will adopt PG&E's five-year estimate.

## 8.5 Other Power Generation Expenses

### 8.5.1 CPUC Account 549 (PG&E Account 793): Miscellaneous Other Power Generation Expenses

This account includes the expenses associated with various expenses not assignable to other generation operation accounts. PG&E used a five-year average for both labor and materials expenses. DRA used the two-year average to calculate its base estimates for both labor and M&S to reflect the decline in the recorded expenses in this account since 1989. During hearings, PG&E's witness testified that in this account labor expenses had declined since 1987. PG&E believes that since this account has shown slight fluctuation over the past five years, the "fluctuating" methodology is appropriate. This is an account that PG&E chose not to discuss in its opening brief.

We are not persuaded by PG&E's arguments as to this account. We will adopt DRA's estimating methodology for Account 549, and authorize $230,000.

### 8.5.2 CPUC Account 551 (PG&E Account 470): Supervision and Engineering

This account includes the expenses associated with general supervision and engineering for maintenance activities at other power generation stations. DRA used a 1990 recorded figures for this account for both labor and M&S because this particular account has shown a declining trend. PG&E, on the other hand, used a five-year average to calculate its base estimates. PG&E did not address this account in its opening brief, stating in its reply brief that this account's labor show some weather dependency.

Since PG&E's rationale for its estimating methodology is not well explained, we will adopt DRA's recommendation of using 1990 recorded data to develop Test Year 1993 numbers, adopting $131,000.

## 8.6 Electric Transmission Expenses

The electric transmission accounts include substation structures, substation equipment, poles, towers, conductor, underground lying equipment, and miscellaneous plant operated at 50 kV and above. (Exhibit 6, p. 6-1.) PG&E contends that the operation of its transmission system is rapidly changing, as these facilities are being used more extensively to gain access to excess generating capacity at other utilities through power purchases and to purchase power from a growing number of nonutility generators whose sites and resulting power flows are not under utility control.

As with other accounts already discussed, both DRA and PG&E used one of two methodologies for each of the accounts (discussed in this section): either data from the last recorded year (1990) or the average of anywhere from two to five years of data. Overall in this area of transmission expenses, DRA reduced PG&E's requested amount by $2,060,000. PG&E's overall estimate was $65,523,000, with DRA's estimate at $63,463,000. The main area of differences are in estimates of EMF expenses, power control staffing levels, tree trimming and removal expenses, and as always, estimating methodologies. We note that given the total dollars involved in these accounts, a disagreement of a little over $2 million is not terribly significant.

### 8.6.1 CPUC Account 560 (PG&E Account 850): Operations, Supervision, and Engineering

This account includes the expenses associated with general supervision and engineering for transmission system operations. Also included in this account is a request to fund 5.5 additional employees. According to PG&E, these employees are needed to handle inquiries about EMF and to measure EMF levels whenever requested by PG&E customers. The total dollars associated with Account 560 are $3,965,000 for PG&E and $3,310,000 for DRA. This difference of $655,000 is broken down as follows: $502,000 is due to differences in the estimating methodology and $152,000 is due to differences regarding request for additional employees to handle EMF matters.

First, we will discuss the differences in estimating methodologies. PG&E used 1990 recorded data for its base estimate for both labor and M&S expenses. On the other hand, DRA used a five-year average to establish its base estimate for both portions of this account. PG&E believes its last recorded year approach is more appropriate because the recorded data show a steady three-year increase from 1988 through 1990. PG&E says this is consistent with its policy to use 1990 recorded expenditures whenever a steady trend over the last three years is observed either up or down. PG&E believes the trend will continue upward, recognizing increased workload associated with transmission utilization. DRA, on the other hand, believes that because of sharp declines in expenses between 1986 and 1988 and then sharp increases between 1988 and 1990, a five-year average is a more reasonable approach. We agree with DRA that the swings observed in this account are best handled by use of a five-year average. We disagree with PG&E that simply because the Commission is formally investigating EMF issues in an investigation, there will necessary be increased activity in the EMF and transmission-related fields.

As to the issue of additional employees for the EMF area, we find PG&E's request for 5.5 additional employees to be excessive. This is a dramatic increase in this area given the much talk about productivity of PG&E employees. We find DRA's recommendation of only allowing three employee positions to be more than adequate to address this area. We note that the upcoming investigation will address many issues relating to this field. It may or may not be the case that PG&E continues to provide free estimates of EMF measurements to any and all customers who request it. Certainly, the ways of supplying EMF information packets at the levels that have occurred in the past should not require the number of additional employees that PG&E seeks. We find DRA's argument that EMF inquiries peaked in late 1990 and 1991 to be persuasive. The later months of 1990 showed requests on the decline. (Exhibit 221.) In addition, PG&E's witness on the topic was rather vague as to the actual time involved in taking EMF measurements, if they are to continue, giving a range of one hour to two days for the projects. Finally we note that PG&E admits that the company itself does not know what any given EMF reading actually means when done for the customer nor does the literature provide guidance on this point. Therefore the customer is not in a position to determine whether a reading indicates harmful or harmless levels. We will leave it to the investigation currently set for hearings in December 1992 to determine more of these issues. For the time being, we find PG&E's request to be excessive and will adopt DRA's recommendation of funding only three additional employees rather than 5.5.

8.6.2 CPUC Account 561 (PG&E Account 859): Load Dispatching

This account includes expenses associated with load dispatching operations related to the transmission of electricity. The parties have no disagreement as to what methodology to use for their estimates. Both PG&E and DRA used 1990 recorded expenses. However, the parties disagree as to the number of additional employee positions needed in this account. PG&E's overall figure for this account is $7,223,000 while DRA's figure is $7,017,000. The difference of $206,000 is due to DRA's reduction of PG&E's request for seven additional employees down to four additional employees.

Of the seven additional employees, PG&E is requesting three additional dispatchers hired primarily to relieve the existing 15 dispatchers for training purposes, and four scheduler positions. PG&E argues that these additional positions will address the increased workload associated with the increased use of PG&E's transmission facilities and provide relief to implement training programs necessary to address the increasing system complexity and changing system operations technology. PG&E points out that currently once dispatchers and schedulers go on shift in the power control department, there is no formal training because in their opinion there are not enough dispatchers to allow for taking the person off shift. PG&E desires to take personnel off shift to allow them to go through simulator training, a controlled series of events so that they will be adequately prepared when an event occurs. (RT 15:1031.)

On the other hand, DRA, while agreeing that there has been a workload increase in connection with this account, believes that seven additional positions are too many. DRA recommends one additional dispatcher to allow rotating training and three additional schedulers should be sufficient to handle the increased growth. DRA points out that there is no discernable inadequacies in the current job performance of the dispatchers. Therefore a simulator training program could be introduced more gradually with the addition of only one new dispatcher. Likewise, the data provided by PG&E as to the need for four additional schedulers is not as compelling as DRA's position. DRA believes that authorizing three new schedulers is more than generous.

We agree with DRA that PG&E should be able to meet its increasing workload with four rather than seven additional positions in this account. Once again we applaud the productivity of PG&E employees and have confidence that they will be able to deal with the increasing complexity of the transmission system.

### 8.6.3 CPUC Account 570 (PG&E Account 552): Maintenance of Station Equipment

As its name indicates, this account includes the cost of maintaining station equipment. PG&E requests a Test Year 1993 estimate of $11,250,000 for this account. DRA recommends $10,607,000 for this account. The difference of $643,000 is due to a difference in methodology for the labor portion of this account.

PG&E and DRA both used the five-year average to calculate the materials and services portion of the expenses in this account. For labor, however, PG&E used 1990 recorded data as its base estimate and DRA again used a five-year average. DRA justifies its five-year average because it claims there were substantial fluctuations associated with these labor expenses. PG&E, on the other hand, claims that since the trend for the last three years has been an increasing trend, that the use of last recorded year's data is more appropriate. We will adopt DRA's estimate for this account since we believe that the fluctuations have in fact occurred over the last five years for both the M&S and labor portions of Account 570, adopting an estimate of $10,607,000.

#### 8.6.4 CPUC Account 571.73 (PG&E Account 573): Tree Trimming

This account includes the expenses associated with trimming trees so that they do not interfere with transmission facilities. PG&E's estimate for Test Year 1993 is $3,114,000 while DRA's estimate is $2,558,000. This difference of $556,000 was not due to methodological differences. Both PG&E and DRA used a five-year average as the base estimate for labor expenses and the 1990 recorded expenses as the base estimate for materials and services. The area where PG&E and DRA differ relates to the costs associated with removal of drought-killed trees. DRA does not dispute that the drought conditions in this state over the past five years have killed a significant number of trees along PG&E's rights-of-way and that those dead or dying trees must be removed. PG&E estimated that 12,600 trees would have to be removed at a direct cost of $70.00 per tree to assure transmission lines conform to California's line clearance provisions. On the other hand, DRA believes that some of that cost of removing those trees would be offset by a savings in routine tree trimming costs. At hearings, PG&E disputed that removal of drought-killed trees would be offset by tree trimming expenses because PG&E alleged that many of these drought-killed trees were located some distance from the power lines and are not in fact the same trees that PG&E routinely trims. (Exhibit 221, p. 5-6.) PG&E believes its estimate of $70.00 per tree is quite conservative given an analysis of similar tree removal work done during 1991. Actual dead tree removal costs incurred on several contracts during 1991 showed a range from $76.33 to $316.34 per tree.

DRA points out that PG&E's original information provided to DRA did not distinguish between the cost of tree trimming and the cost of tree removal. Therefore DRA calculated the costs for both activities together. DRA then divided the costs of tree trimming and removal in 1991 by the number of trees removed and trimmed to arrive at a cost of $32.00 per tree. (RT 16:1070, and Exhibit 121.) DRA believes it is unfair to allow PG&E the higher estimate of $70.00 a tree based on information made available for the first time during rebuttal hearings. DRA calls PG&E's information presented in its rebuttal Exhibit 221 carefully selected statistics which should be rejected. PG&E counters that argument by reiterating that the trees subject to removal are hazard trees and by definition, large trees. Since power lines stand between 25 and 40 feet from the ground the tree must be as tall as the line to present the hazard. There is also an additional risk that the tree might fall on the line during the removal process. PG&E believes these factors make it obvious that the cost of removal of large trees is more expensive than routine trimming.

We find DRA's showing for this account regarding tree trimming to be more compelling. We note that DRA did take an average of tree removal and trimming to arrive at a cost of $32.00 per tree. PG&E was rather vague as to the number of trees that needed to be removed that were not part of the tree trimming universe. We note also that the use of competitive bidding for tree removal has lowered tree removal costs in recent years.

Therefore we will reduce Account 571.73 by DRA's recommended $556,000.

8.7 Distribution Expenses

PG&E's total estimate of $256,677,000 for electric distribution was reduced by DRA by $11,601,000. The differences between the parties are principally due to disagreements over EMF support and customer response expenses, training for SCADA and distribution automation, strategic technology support expense, cable elbow replacement accounting, tree trimming and removal expense, and as always, differences in estimating methodologies.

8.7.1 CPUC Account 580 (PG&E Account 950): Operations, Supervision, and Engineering

This account includes the expenses associated with the general supervision, engineering, and direction of the operation of the distribution system. Both PG&E and DRA used 1990 recorded data to estimate labor and M&S expenses. PG&E requests $24,104,000 for this account. DRA's estimate of $22,961,000 is lower due to a dispute on the number of additional personnel PG&E needs to deal with EMF customer concerns. The difference is $1,143,000. PG&E has requested an additional 25 new positions, while DRA believes 6.25 positions are more than adequate to deal with EMF issues. DRA believes PG&E's request is excessive for basically the same reasons as set forth regarding CPUC Account 560 in the transmission area.

In order to be consistent with that previous account, here we will also adopt DRA's estimate of 6.25 additional positions rather than PG&E's 25 positions. We note that the outcome of I.91-02-012 has not yet been determined by the Commission. We find that PG&E's request for 25 positions to be excessive in light of the uncertainty of the outcome of that proceeding. This is particularly true in light of the fact that a resolution of the investigation may not occur until well into 1993.

8.7.2 CPUC Account 583.2 (PG&E Account 952): Overhead Line Expenses

This account covers the expenses associated with operating overhead distribution lines. Included in this account are the costs of patrolling, changing line transformer taps, making load tests, and transferring loads. PG&E used a five-year average for both labor and M&S costs to come up with its base estimate for Test Year 1993. DRA used 1990 recorded expenses for both categories in order to better reflect the impact of PG&E's SCADA system and its distribution automation (DA).

DRA points out that SCADA provides supervisory controls of substation and gathers and displaying data about transformers, circuit loading, and voltage profiles. SCADA can also announce station alarms in a matter of seconds and sometimes even resolve them without involving field personnel. Since this technology, SCADA, and others are designed to save time and money, DRA believes the most recent recorded year, 1990, best illustrates what will be needed for Test Year 1993.

PG&E admits in its brief that it did not describe in detail the reason for a particular estimating methodology for each account, this account being one of those. Rather, PG&E says that it reviewed the factors that influence each account in determining the estimating method to be used. Based on that review, PG&E then selected one of three estimating methodologies: (1) last recorded data for accounts that exhibited trends; (2) averages for accounts with significant outside influences and to smooth fluctuations; and (3) three-, four-, or five-year averages based on historical expenditures and the extent of outside influences. PG&E claims that DRA did not base its estimates on such principles but rather use the circumstance that would produce the lowest estimate.

For this account we find that PG&E failed to make an affirmative showing. We find DRA's arguments for lowering the requested amount for this account to be compelling.

8.7.3 CPUC Account 585 (PG&E Account 955): Street Lighting and Signal Systems

This account includes the expenses associated with the operation of street lighting and signal systems that are owned or leased by PG&E. The parties disagree on an amount of $27,000. Both PG&E and DRA used the four-year estimate for M&S expenses. PG&E used a five-year average for its labor costs while DRA used the four-year average. DRA excluded 1986 expenses for labor because they were higher than in any subsequent year due to storm damage. On the other hand, PG&E argues that the weather since 1986 has been mild rather than normal. PG&E argues that it is in fact appropriate to include 1986 as one of the five years for averaging purposes. We concur with PG&E on this account and will adopt its estimate for Test Year 1993.

8.7.4 CPUC Account 588 (PG&E Account 961): Miscellaneous Distribution Expenses

This account includes the expenses associated with the distribution systems not accounted for elsewhere. Also included in this account are expenses for technical training. PG&E's total request for this account is $31,503,000, while DRA recommends $29,187,000. The difference of $2,316,000 is divided as follows: $495,000 disputed over SCADA support, $1,037,000 disputed over strategic technologies, and $784,000 is disputed due to methodological differences.

First, as to methodological differences, both PG&E and DRA used 1990 recorded data to estimate labor expenses. The dispute arises over the appropriate time period to use for the M&S estimate. DRA used 1990 for this estimate to reflect the downward trend in M&S expenses for this account. PG&E, on the other hand, chose to use a five-year average. We concur with DRA that use of last recorded year 1990 is more appropriate given the data in this account.

The parties are also in disagreement on the amount of money needed for training distribution employees in SCADA on an on-going basis. DRA recommends a reduction in training of one-half, eliminating some $498,000. DRA justifies this reduction by pointing out that SCADA is not yet fully implemented. PG&E's own witness testified that less than 20% of substations currently have SCADA installed in them. (RT 16:1043.) DRA points out that PG&E has not shown that the system will be fully implemented during Test Year 1993. Therefore DRA does not believe it necessary to train all employees on a system not yet installed.

PG&E counters DRA's arguments with its position that SCADA is moving into other territories. PG&E claims that DRA did not review PG&E's total planned need capital expenditures in its capital estimates for partial SCADA implementation. While PG&E asserts that those employees that are involved in SCADA are the ones that will be trained under this proposal, PG&E's witness could not give details as to what percentage of substations would have SCADA installed during the test year.

We agree with DRA that the record is still unclear as to whether all distribution employees truly need to be trained in SCADA during Test Year 1993. In light of PG&E's inability to make the record clear on this point, we will adopt DRA's reduction of $498,000 for SCADA training.

Finally, as to DRA's last recommended reduction for this account of $1,037,000, DRA chose not to address this portion in its opening brief. PG&E has requested 24 additional workers to support strategic technology. DRA recommended only three additional workers. PG&E argues that strategic technologies are intended to capture productivity savings and improved customer service. The development and expansion of strategic technologies such as computer coordination and administration in local engineering and operations offices increase expense costs in a number of accounts. The costs include software development, construction, maintenance and operation training, and system administration. (Exhibit 6, p. 7-14.)

In our effort to be consistent with our treatment of additional employee positions for other accounts, we will adopt DRA's recommendation for funding levels in this account for only three additional employee positions. We find PG&E has given us inadequate justification for such a large request of additional employee positions. Hopefully, the productivity gains expected by these technologies will in fact occur and not result in a requirement for an ever-growing personnel population.

### 8.7.5 CPUC Account 591 (PG&E Account 651): Maintenance of Structures

This account includes the costs of labor, materials, and other expenses incurred in maintaining structures. PG&E used 1990 recorded expenses for its base estimate for labor and M&S, while DRA used the three-year average for both portions. PG&E's method necessarily included the large increase between 1989 and 1990, weighting it more heavily. DRA believes the three-year averages more appropriate in order to reflect the substantial fluctuations occurring in this account. During hearings, the PG&E witness could not identify in 1990 recorded data any expenditures associated with structural maintenance per se. He testified that 99% of the expenditures were for hazardous waste management and spill containment. (RT 16:1046.) Therefore PG&E argues that even though this account is entitled Maintenance Structures it in fact is used much more for management of hazardous waste in substation facilities. As it been discussed previously in prior accounts, PG&E believes this would be a continuing area of escalation. PG&E also accuses DRA of selecting the methodology that will result in the lower estimate for this account.

We are unpersuaded by PG&E's arguments vis-a-vis this account. We will adopt DRA's estimates for Account 591.

### 8.7.6 CPUC Account 593.62 (PG&E Account 662): Cleaning Insulators and Bushings

This account includes the expenses associated with cleaning overhead distribution insulators and bushings. PG&E chose a five-year average to calculate the base estimate for labor and M&S expenses. DRA preferred 1990 recorded expenses. PG&E argued that its use of a five-year average was more appropriate to capture 1986 data. Since 1986, as has been discussed previously, weather has been mild rather than normal. On the other hand, DRA believes that its use of 1990 recorded expenses is legitimate because the use of nonceramic insulators should result in expenses associated with this account declining. (Exhibit 103, p. 6-12.)

As we have stated regarding other accounts, we generally concur with PG&E's analysis that including the year 1986 in averages for accounts that are somewhat weather-related is reasonable. We certainly hope that the drought does not continue indefinitely. Therefore we will adopt PG&E's estimate for CPUC Account 593.62.

### 8.7.7 CPUC Account 593.63 (PG&E Account 663): Replacing Line Insulators

This account includes the costs of labor, materials, and other expenses incurred in replacement of and minor additions to line insulators. PG&E's and DRA's difference of $228,000 is due to an estimating difference. PG&E used a five-year average for its base estimate. DRA believes a four-year average is more appropriate in order to discount the unusually high expenses of 1986. Consistent with our decisions on accounts that are weather-dependent, we believe it is appropriate to include the year 1986 for averaging purposes. Therefore, we will adopt PG&E's estimate for CPUC Account 593.63.

**8.7.8 CPUC Account 593.65 (PG&E Account 665): Moving and Relocating Poles and Guys**

This account is described as including expenses associated with moving and relocating distribution poles and guys. DRA and PG&E both used a five-year average for their base estimates for materials and services for this account. PG&E chose a five-year average for its labor estimate while DRA used a three-year average to reflect in its opinion a declining trend in the labor expenses associated with this account.

We concur with DRA that a three-year average is more appropriate giving the declining trend in this account and will therefore adopt DRA's Test Year 1993 estimate for Account 593.65.

**8.7.9 CPUC Account 593.66 (PG&E Account 666): Pole Treating**

This account includes the costs of labor, materials, and expenses incurred in the testing and treating of wooden distribution poles. PG&E chose to use a five-year average for its base estimate for labor and a four-year average for its base estimate for materials. DRA determined that a three-year average was more appropriate given that expenses in this account in 1986 and 1987 were higher than they have been in any subsequent recorded years.

We concur with DRA that its estimate is more realistic for what could be expected for Test Year 1993 and therefore adopt it.

**8.7.10 CPUC Account 593.68 (PG&E Account 668): Reconditioning Conductors**

This account includes the costs of labor, materials, and other expenses incurred in reconditioning conductors. PG&E and DRA disagree as to $1,608,000. PG&E used a five-year average for its base estimate of labor and a four-year average for its base estimate of materials expenses. PG&E points out that this is yet another account that is impacted significantly by weather and storm damage. PG&E argues that including 1986 in the averages is reasonable given the mild, drought-year weather that has continued since then.

DRA uses a three-year average for both its labor and materials estimates, basing it on SCADA and DA having provided better circuit protection, which has resulted in a declining trend in this account.

We find PG&E's arguments concerning the value of including 1986, a normal year, in its estimates to be persuasive. Therefore we will adopt PG&E's estimates for Account 593.68.

8.7.11 CPUC Account 593.72 (PG&E Account 672): Other Overhead Line Maintenance

This account includes the costs of labor, materials, and other expenses incurred in installing or removing additional clamps or insulators on guys in place, realigning poles, relocating cross-arms, and repairing roadways and grounds. PG&E and DRA disagree over $599,000 in this account for the Test Year 1993 estimates. Both PG&E and DRA agree on the use of a three-year average to estimate labor expenses. However as to M&S expenses, PG&E used a five-year average while DRA used a four-year average. DRA argues that it is appropriate to exclude the high level of expenses observed in 1986 associated with heavy storm damage. Once again, PG&E argues that to exclude a nondrought year from the estimates is unrealistic. Once again, we agree with PG&E since this is a weather-dependent account, and will adopt PG&E's estimate for Account 593.72.

8.7.12 CPUC Account 593.73 (PG&E Account 673): Tree Trimming

This account includes the costs of labor, materials, and expenses associated with trimming trees after the initial installation of distribution facilities. While we have visited the issue of tree trimming already in this decision, in this account the difference between DRA and PG&E totals $1,718,000. Both PG&E and DRA used a five-year average to estimate labor expenses. For the estimate of materials expenses, PG&E used the 1990 recorded figures while DRA used the expenses budgeted for 1992. DRA justifies its position by the following reasons: (1) once again DRA believes that the removal of drought-damaged trees will reduce tree trimming thereby offsetting the increase in tree removal costs; (2) PG&E has been using the system of competitive bidding for tree removal, resulting in decreasing costs. Therefore DRA argues that no additional increase above the 1992 budget level is necessary for 1993.

PG&E contends that DRA's use of 1992 budget estimates is just another way to reduce the PG&E estimate. We disagree with PG&E and determine that it is appropriate to be consistent with our prior discussion on tree trimming and drought-killed tree removal. Therefore we will adopt DRA's estimate for Account 593.73.

### 8.7.13 CPUC Account 593.74 (PG&E Account 674): Vegetation Control

This account includes the costs of labor, materials, and other expenses incurred in controlling the growth of vegetation subsequent to the initial installation of distribution facilities. PG&E used a five-year average as its base estimate for both labor and M&S expenses while DRA used a two-year average for both. DRA justifies its position by pointing to the declining trend in this account.

We note PG&E gives little specific justification for its request on this account. We find DRA's points persuasive. We will therefore adopt DRA's estimate for Account 593.74.

### 8.7.14 CPUC Account 593.75 (PG&E Account 675): Rights-of-Way Clearing

This account includes the expenses associated with clearing distribution rights-of-way after the initial installation of distribution facilities. PG&E believed a five-year average for both its labor and M&S expenses was more appropriate, while DRA used a two-year average for both to take into account the declining trend in these expenses.

We concur with DRA that its approach will more accurately reflect the reality of this account in Test Year 1993.

8.7.15 CPUC Account 594 (PG&E Account 654): Maintenance of Underground Lines

This account covers the costs of labor, materials, and other expenses incurred in the maintenance of underground distribution lines. PG&E's total request for this account is $9,464,000. DRA recommends $7,333,000, a reduction of $1,731,000. Included in this estimate for this account are the costs for cable elbow replacement. A cable elbow is a device attached at the end of a piece of cable that allows connection of the cable to a transformer or another piece of equipment. The dispute in this account arises out of DRA's opinion that this cost should be capitalized rather than expensed.

DRA argues that elbow replacements have been occurring as a matter of maintenance since they were first installed in the early 1980s. In fact, in 1989, due to a significant number of premature failures, PG&E began an elbow replacement program. DRA points out the costs of that program were capitalized. DRA is concerned that PG&E's attempt to have the costs of this program treated as expenses will result in double-counting. This is because the work envisioned is the same.

PG&E, on the other hand, argues that the work schedule to be done in 1993 is in fact routine maintenance of underground distribution lines and therefore is properly charged to expense. PG&E points out that DRA did not review any FERC accounting guidelines in making its recommendation to capitalize these replacements. PG&E also notes that the witness who has recommended this accounting change is not an accountant. PG&E urges that this activity is more appropriately kept in the expense category since it clearly benefits customers by improving service reliability.

We concur with PG&E as to this account. The costs are more appropriately treated as expense items and we will therefore adopt PG&E's Test Year 1993 numbers.

<u>8.7.16 CPUC Account 595 (PG&E Account 655): Line Transformers</u>

This account covers the costs of labor, materials, and other expenses incurred in the maintenance of distribution line transformers. PG&E and DRA disagree as to methodology for estimating. The parties agree on the labor portion of the estimates, both using five-year averages. However, as to the costs of materials and services, PG&E chose to use a four-year average while DRA used a five-year average. DRA's position is that a five-year average is more accurate because this account tends to fluctuate substantially. We will adopt DRA's numbers in this account.

**8.7.17 CPUC Account 593 (PG&E Account 656): <u>Maintenance of Services--Overhead</u>**

This account includes the costs of labor, materials, and other expenses incurred in maintaining overhead service lines. PG&E and DRA disagree regarding an amount of $86,000. Since this is another weather-dependent account, PG&E used a five-year average for labor expenses and a four-year average for material expenses. On the other hand, in order to exclude the storm year 1986, DRA used a four-year average for labor and the five-year average for materials. As we have already stated regarding other accounts, we believe inclusion of 1986 with the following mild weather-drought years is appropriate for estimating Test Year 1993. We therefore adopt PG&E's estimate for this account.

**8.7.18 CPUC Account 596 (PG&E Account 658): <u>Maintenance of Street Lighting and Signal Systems</u>**

This account includes the maintenance of street lighting and signal systems. PG&E used a five-year average to estimate labor expenses and a three-year average to estimate material and supply expenses. DRA believed a three-year estimate was more appropriate for both portions due to the declining trend in recorded data. We concur with DRA in this account and believe it more appropriate to use a three-year trend as the best estimate for Test Year 1993.

### 8.7.19 CPUC Account 597 (PG&E Account 659): Maintenance of Meters

This account includes the expenses associated with the maintenance of meters and the equipment used to test them. PG&E chose to use a three-year average for its M&S expenses while using 1990 recorded data for its labor estimate. DRA, on the other hand, used 1990 recorded data for both its labor and M&S estimates in order to reflect the declining trend in both portions of this account. We concur with DRA that its choice of estimating methodology gives a more accurate picture of what would be a reasonable estimate for Test Year 1993.

### 8.7.20 CPUC Account 598 (PG&E Account 660): Miscellaneous Distribution Plant

This account includes the miscellaneous expenses involved in maintaining the distribution plant. Once again the parties dispute the appropriate methodology for estimating purposes. PG&E chose a five-year average for its base estimate of both labor and M&S expenses. DRA believed that use of 1990 recorded data is more appropriate given the declining trends in both portions of this account. Once again we concur with DRA as to its chosen methodology for this account.

## 8.8 Customer Account Expenses

PG&E's estimate of $118,063,000 for Electric Department customer account expenses (excluding uncollectible accounts) exceeds DRA's estimate of $115,325,000 by $2,738,000. This total difference is the result of the following individual differences: $1,446,000 due to differences in estimates for customer growth in PG&E Accounts 971, 973, and 974; $1,153,000 due to estimate differences in PG&E Account 976; and $138,000 due to DRA's Steam

Department expense adjustment. The Steam Department expense adjustment will be addressed in a later portion of this decision. At hearings, the parties agreed on the appropriate uncollectible factor to use for Test Year 1993. PG&E's witness changed his recommended factor from 0.294% to 0.300% based on DRA's request to update this factor by estimating the econometric model with year-end 1991 data. We will now discuss each customer account where there is a dispute between DRA and PG&E for the Electric Department.

### 8.8.1 CPUC Account 902 (PG&E Account 0971): Meter Reading Expenses

This account includes the labor and other costs associated with meter reading. PG&E proposes to increase meter reading expenses in this account by $499,000 to accommodate customer growth. DRA disputes this requested increase and believes that PG&E should be able to accommodate the additional workload by continuing to implement operating efficiencies. DRA's witness testified that PG&E already has the computer equipment available to improve its communication and scheduling operations. DRA contends that rather than assuming that meter reading expenses will automatically increase on an average-customer basis, productivity measures PG&E already has in place may well contain these expenses at 1990 levels or lower them. (RT 16:1135-1137.)

PG&E maintains the position that each year the number of customers continues to grow with a related increase in the volume of customer transactions. PG&E points out that DRA's argument is weak because it is founded on intangible, unquantifiable perceptions of improvements. PG&E points out that it has already undergone reorganization into divisions, and no savings are reflected in its estimates. For example, PG&E has already closed or consolidated some 20 offices. (RT 16:1130.) PG&E concedes that while it may be true that small improvements may be made in the day-to-day operation, other factors may work against cost reduction. PG&E claims that it looked at technological improvements, but these must be balanced against service requirements and the need for a community presence. PG&E believes that expense projections which are based on the level of customer growth represent a reasonable estimate since its increased volume of customer transactions clearly increase the resources necessary to maintain service.

We concur with DRA as to its request for CPUC Account 902. We note that DRA witness testified that in his opinion PG&E customers are generally satisfied with the level of service. Once again we are confident that PG&E's productivity measures will be sufficient to meet customer growth.

### 8.8.2 CPUC Account 903 (PG&E Account 0972): Customer Contracts and Orders

This account includes the labor and other costs for positions assigned to offices or to the field, for handling customer inquiries, service requests, energy costs inquiries, and other requests made by telephone or in person. PG&E requests an increase in this account of $293,000 for customer growth, some $970,000 for changing its accounting procedures for general conservation costs inquiries, and $961,000 for meeting the demands of cultural and language diversity. (Exhibit 6, pp. 8-4 through 8-11.) For the same reasons stated in the above account, we will reject PG&E's arguments regarding customer growth. Likewise, we find PG&E's request for changing its accounting procedures for conservation costs inquiries to be reasonable. However, we are concerned as to the size of the request for increases in cultural and language diversity of $961,000. We believe some of this should be captured by what we are allowing for customer growth generally. Therefore we will reduce the request of $961,000 by $461,000, allowing $500,000 for this activity.

### 8.8.3 CPUC Account 903 (PG&E Account 0973): Customer Billing and Accounting

This account includes labor and other costs for positions assigned to analyzing rates to assist customers in choosing the correct or most advantageous rate schedule. Also included are the costs associated with order, processing, teleprocessing, and bill preparation. PG&E requests an increase of $4,000,000 to rewrite its customer information computer program (CIS) and an additional $283,000 for customer growth.

We note that we directed PG&E to give us a report on its progress to rewrite its CIS program in our last GRC. However, we believe that a $4 million expenditure has not been adequately justified. Once Again we agree with DRA's arguments regarding customer growth.

### 8.8.4 CPUC Account 903 (PG&E Account 0975): Collecting Expenses

This account includes the labor and other costs for employees assigned to credit and collection work. PG&E seeks an increase of $372,000 for customer growth for this account. DRA recommends a full disallowance of that increase on the ground that PG&E's productivity gains should balance out customer growth. For this subject area we once again agree with DRA that this moderate increase for customer growth should be offset by productivity.

### 8.8.5 CPUC Account 905 (PG&E Account 0976): Miscellaneous Customer Accounts Expense

This account records the labor and other expenses resulting from positions which cannot be categorized in other activities. DRA recommends exclusion of two items in this account.

First, DRA recommends disallowance of $659,000 for the customer payment option communication program and $494,000 for the customer's service program evaluation project.[4]

First, we will address the customer payment option communication program. PG&E justifies this request based on prior experience. PG&E believes to routinely develop winter customer information programs that communicate payment options to customers will meet a significant customer need. PG&E plans to provide this program in English as well as other languages to achieve maximum value. DRA's argument against this program is basically that it believes the existing program appears to be working satisfactorily. DRA believes that the special advertising campaign PG&E conducted during the 1990-1991 cold snap is not necessarily something that would need to occur on an annual basis. Likewise, DRA points to customer communication through PG&E's newsletter and various other media tools to inform customers of various programs. We agree with DRA regarding the customer payment option program. There is already adequate money being spent in this area and the requested increase of $659,000 will not be allowed.

The second area where PG&E requests an increase which DRA disputes relates to its evaluation and analysis of customer service programs. PG&E proposes to implement a program of using industry-accepted methods of market research to evaluate the value of existing programs, services, and methods of service delivery from the customer's perspective. Armed with this information, PG&E asserts that adjustments can be made to ensure the most significant needs are being met.

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4 The expense adjustment of $138,000 due to DRA's recommendation regarding how to treat PG&E's Steam Department will be dealt with in the section dealing with all Steam Department issues.

DRA opposes these requested increases once again stating that it believes the existing program appears to be working satisfactorily. PG&E counters that DRA does not recognize that this program is actually a cost-reducing expenditure in the long run. PG&E maintains the need to contact customers to determine how they feel about the value of existing programs is cheaper in the long run than reacting to customer complaints about levels and methods of service delivery. By focusing on customer value, and the services most desired by customers, PG&E argues it can reduce costs for nonessential services and increase the value of the services it does provide. PG&E believes DRA's opposition to this is inconsistent with the progressive interpretation of the utility's obligation to continually improve its service to ratepayers. We agree with PG&E as to this portion of this account and will authorize the $494,000 increase requested by PG&E.

Finally, we note that this account included one other recommendation by DRA in its original exhibit and at hearings. DRA recommended an upgrade to PG&E's telephone network in order to reduce average customer waiting times. DRA's initial research indicated it may cost as much as $10 million to fulfill this requirement. (RT 16:1138.) Given DRA's testimony that overall the level of service is adequate at this time, we see no reason to order PG&E to pursue this area. PG&E's opening brief indicates that it will complete a study in this area by October 1992. While that study may be provided to Commission staff, we are not in any way ordering that the results of that study be implemented at this time.

## 9. Results of Operations for Electric Department--Administrative and General Expenses

### 9.1 Overview

Administrative and general (A&G) expenses represent indirect expenses not chargeable to operations and maintenance or other specific functions. PG&E presented its report on A&G

expenses for electric operations through two witnesses. DRA used five different witnesses to address various areas of PG&E's reports. While this section of the decision deals specifically with PG&E's Electric Department, we will address A&G matters that relate to both electric and gas, referred to as common issues.

PG&E estimates $504,979,000 for Electric Department A&G expenses. DRA's estimate is $81,109,000 less, resulting in an estimate of $437,342,000. This difference is composed of disagreements on a variety of programs covering some eight different A&G accounts. The areas of dispute include the following: the appropriate allocation factor for Diablo Canyon costs, how to handle PG&E's incentive pay programs, ratepayer funding of child care center, appropriate level of outside legal services, ratepayer funding of investor relations and other memberships/dues, the equal opportunity purchasing programs (EOPP) and women- and minority-owned business enterprises (WMBE), the necessity of the blueprint for learning training program, line of credit fees, and the very large and very complicated area of nonhealth care benefits, medical benefits, and post-retirement benefits other than pensions (PBOPs).

We will break down these areas of dispute by account. We note that for certain areas more than one account is involved. We will therefore have the bulk of our discussion in the first account discussed, making reference thereto as necessary.

## 9.2 Account 920 (PG&E)--Administrative and General Salaries

PG&E requests $107,413,000 for the Electric Department portion of Account 920. This is $5,536,000 larger than DRA's estimate. This difference is due to a dispute regarding how to use the results of the Diablo Canyon Use Study to the tune of $2,945,000; $2,415,000 is due to differences in the way PIP was removed from A&G in the recorded data before spreading incentive pay across all labor accounts; disagreements over EOPP costs of a $141,000 (which actually was resolved during the Update hearings);

and $35,000 due to DRA's exclusion of the family benefit coordinator position requested by PG&E.

### 9.2.1 Diablo Canyon Use Studies and Appropriate Allocation Factor

Exhibit 41, the Diablo Canyon Use Studies, was filed pursuant to Ordering Paragraphs 9 and 10 of D.89-12-057, PG&E's last GRC decision. (34 CPUC2d 199, 439.) The purpose of this report was to provide a comprehensive study to determine the proper allocation of A&G expenses between the Diablo Canyon nuclear powerplant and other PG&E operations. Both PG&E and DRA cite Exhibit 41 as the source for their positions that they have correctly allocated A&G costs to Diablo Canyon.

In response to Diablo Canyon Use Studies, DRA filed comments on March 29, 1991. DRA concluded that the Diablo Canyon Use Studies collaborate the revenue requirement implications of Diablo Canyon incorporated in D.89-12-057. DRA recommended in those comments that no further action is necessary and believed that the cost allocation issue raised in the last GRC is resolved. The parties are in agreement that Exhibit 41 is responsive to D.89-12-057 and has in fact been reviewed and accepted by DRA and other parties. The disagreement between the parties arises from what is the appropriate allocation factor to use for base year 1990 in developing figures for Test Year 1993. PG&E contends that 13.52% of total A&G costs from recorded data 1990 should be assigned to Diablo Canyon. DRA believes, also citing Exhibit 41, that the appropriate allocation factor should be 15.8%.

Both the 13.52% factor and the 15.8% factor appear in Exhibit 41. The debate between the parties is over which number is appropriate to apply to 1990 figures. PG&E argues that the lower figure is appropriate for the following reasons. PG&E developed the 13.52% factor based on 1989 A&G labor with the addition of labor related to certain nuclear power generation activities which D.89-12-057 determined should be classified as A&G expenses.

However, during the course of Diablo Canyon Use Study, it was determined that certain costs which were being booked as A&G expenses really belong in other accounts. In Exhibit 41, these costs were adjusted out of A&G expenses and the percentage of restated A&G expenses was recalculated. That recalculation yields 15.8%. This is the appropriate number to use beginning in January 1991. However, these costs were not spread back to non-A&G accounts in the development of 1993 Test Year expenses. PG&E states that to do so would have complicated the development of Test Year 1993 estimates in those other accounts.

Therefore, while the shift in costs from A&G to other O&M expenses will be in effect in 1993, that shift is not reflected in this application. Thus, the 13.52% factor is the appropriate factor to use when assigning 1990 base costs to Diablo Canyon. Using either the 13.52% of the 1990 base or 15.8% of the base adjusted for 1993 accounting results in the same amount of A&G expenses allocated to Diablo Canyon. PG&E argues that DRA has used a simplistic method of allocating the 15.8% of all test year expenses costs in Accounts 920 and 921 to Diablo Canyon. However, PG&E points out that the 15.8% factor is used incorrectly because it is based on A&G costs after removal of some 1990 A&G expenses to O&M accounts.

In developing its estimate of costs for Accounts 920 and 921 (where the same issue of attribution of costs to Diablo Canyon occurs) PG&E held the account to its 1990 recorded level except when increased or decreased for specific activities or adjustments that will be discussed later in this section. PG&E points out that DRA never took exception to the use of 1990 recorded level as a starting point for developing the test year estimates for this account. PG&E concludes that DRA agrees that the 1990 recorded costs should in fact serve as the base for estimating Test Year 1993 costs for Account 920. If that is the case, PG&E states the obvious conclusion is that the correct allocation factor for 1990 is 13.52%.

The issue is further complicated by the fact that the choice is not simply between two different allocation factors. The choice is between PG&E's use of specifically appropriate factors for every item within its estimates of Accounts 920 and 921 versus DRA's simplistic use of one factor across the board. There is no disagreement that PG&E's approach was a multi-step factor which first assigned a portion of 1990 A&G expenses to Diablo Canyon as already discussed and then attributed a specific portion of its test year adjustment to Diablo Canyon. PG&E went through a process by which each specific incremental change was analyzed to determine the appropriate assignment of these costs to Diablo Canyon. The amount attributed to Diablo Canyon was based on the ratio of Diablo Canyon A&G hours to total A&G hours as contained in the detailed worksheets in the Diablo Canyon Use Studies support volumes for the department in which the incremental change originated. (PG&E Exhibit 6, Exhibit 42.) PG&E believes this approach of attributing costs to Diablo Canyon operations on an item-by-item basis matches the intent of both the "Diablo Canyon Accounting Standards, Procedures and Instruction Manual" (Exhibit 43) and the Use Studies Exhibit (Exhibit 41). PG&E concludes that DRA's broad-brush attempt to allocate costs for Diablo Canyon across the board is exactly the type of error PG&E was attempting to guard against.

We agree with PG&E that given the circumstances for recorded 1990 data the 13.52% allocation is more appropriate. We note that in any one recorded year, the actual percentage of A&G expenses charged to Diablo Canyon may not be exactly either of the two proposed percentages. The actual percentage would vary depending on such things as overtime work by various individuals, and the portion of that fixed distribution charged to Diablo Canyon. Therefore when applied to 1990 base year recorded costs, the 13.52% allocation factor is the proper representation of the overall aggregate effect of the Use Study. We will adopt PG&E's attribution of Diablo Canyon costs in Account 920. (We will also adopt it for Account 921, which will be discussed later, for the same reasons stated herein.)

We note that PG&E has stated in its Use Studies report that its intention is to perform such a study every six years, not in every GRC rate cycle. (Exhibit 41, p. 1-4.) We agree that this is reasonable and so there need not be a separate study filed in connection with the next GRC. Assuming our rate case cycle stays the same, the next Diablo Canyon Use Study would be due for the Test Year 1999 rate case.

<u>9.2.2 Incentive Pay--Management and Performance Incentive Plans</u>

The debate between DRA and PG&E over the appropriateness of ratepayer funding for either the Management Incentive Plan (MIP) or PIP programs is not new to this rate case. Since the last GRC PG&E has altered its incentive program as part of its total cash compensation to include virtually all employees. In the last GRC, the MIP which far fewer employees were eligible to participate in, was discussed. In fact, part of the discussion focused on the fact that the Test Year 1987 GRC decision (D.86-12-095, 23 CPUC2d 149) had ordered workshops to explore the issue of incentive pay. Those workshops were not held prior to the Test Year 1990 GRC for PG&E. However, once again the Commission ordered workshops to be held on incentive pay. This time, the workshops were in fact held in February 1991. Therefore in this case we do not have the problem that was described in the last GRC: "The workshops were not held. The record which we had hoped would be developed in these workshops is obviously not available. In the absence of a more developed record, we must evaluate PG&E's request for increased funding of its new MIP based upon the record PG&E has provided in this proceeding." (34 CPUC2d 199, 257 (1989).) Based on the record in that GRC, the Commission disallowed all increased costs for the MIP program, keeping the funding at a level that had been adopted in

1986. Despite doing this, the Commission did endorse the concept of management incentives, stating that "we believe that such plans can be part of a sound management strategy to attain corporate goals and objectives." (Id. p. 260.)

Thankfully we are not presented in this proceeding with the dilemma of the prior GRC, of nonexistent workshops. Workshops did occur and the workshop report regarding PG&E's and other utilities' incentive programs was attached to PG&E's compensation exhibit (Exhibit 10). The conclusions of that workshop report, run by the CACD, make it clear how the issue of incentive compensation programs should be handled.

> "The consensus reached in the workshop was that the Commission should not attempt to micromanage utility incentive compensation programs. Instead of adopting a 'cookie cutter' approach, workshop participants recommend that the Commission review incentive compensation programs utility by utility, as a component of the total cash compensation requested in each utility's general rate case. They proposed, moreover, that the allocation of total cash compensation between salaries and incentives should be left to each utility's discretion.
>
> "Workshop consensus was reached swiftly by parties that rarely agreed. As a result of the workshop and the work performed by D&T (Deloitte and Touche), the Commission now has the basic information it requested on how to evaluate MIPs in a fair, practical, and sensible manner.
>
> "By these measures, the workshop was a success." (Management Incentive Plan Workshop Report, CACD, May 1991, p. 53.)

We note that DRA was an active participant in the CACD workshop on incentive pay. Further, we note that that workshop report made it quite clear, as have past Commission decisions, that incentive pay is part and parcel of the overall compensation scheme. We find DRA's separation of PIP evaluation from its compensation exhibit to be inexplicable, particularly in light of DRA's criticisms that PG&E failed to prepare a complete compensation report. In fact, it is DRA who produced a compensation report that left out an important component of compensation, to wit, incentive pay through PIP. Despite DRA's failure to address PIP in the proper exhibit, i.e., total cash compensation, we will discuss in the context of this account DRA's objections to any inclusion of MIP and PIP expenses in ratemaking.

These same arguments apply to more than Account 920 which we are currently discussing. Therefore the same arguments discussed here by DRA as to why they have disallowed PIP dollars will apply in other accounts and will not be repeated there. Finally, we must note that DRA's position on this entire area of PIP and incentive pay generally was not the easiest to comprehend and understand. Despite that we will try to summarize DRA's objections to PIP.

DRA states that it is fundamentally concerned that a conflict may exist between the employee performance PG&E seeks to reward with ratepayer funds and stated Commission objectives. DRA contends that there has been no Commission validation of PIP and no evidence exists to prove that ratepayers are not being asked to reward performance contrary to their own interests. Secondly, DRA argues that PG&E ties its incentive program to increases in its earnings per share as a measure of improved productivity. DRA believes that an increase in earnings per share could also result from technological improvements paid by ratepayers. DRA contends that incentive payments should be the result of, or be designed to generate, superior performance. DRA says it has no objection to employee incentive programs funded through savings linked to employee performance, but it does object to automatic inclusion of incentive payments in rates. Finally, DRA objects to PG&E's practice of including MIP or PIP costs in expenses transferred to construction work in progress (CWIP). DRA points out that both the shareholder and ratepayer contributions transferred to CWIP earn, for shareholders, a rate of return on rate base that is funded by ratepayers. DRA contends that because the Commission has never given PG&E permission to place incentive costs in rate base that this is inappropriate.

As near as can be understood from DRA's position, it is suggesting disallowance of all identified PIP dollars.

PG&E determines that the dispute regarding Account 920 between PG&E and DRA is $2,415,000 due to differences in the way incentive pay was removed from A&G in the recorded data before spreading incentive pay across all labor accounts. PG&E argues that the problem with discussing PIP in the context of this account is really due to DRA's failure to address the issue in its compensation exhibit. PG&E believes that DRA has ignored the workshop report. PG&E points out that DRA was the first party to question the need to discuss incentives separate from overall consideration of TCC. PG&E contends that DRA has not found a logical way to separate out MIP/PIP issue within the A&G account.

PG&E further notes that DRA's objections to incentive pay out of the context of overall compensation are contradictory to the position DRA took during the CACD workshop. PG&E contends that it is unclear as to what DRA's objections to PIP mean vis-a-vis A&G expenses. Even though he was the designated PIP witness, the DRA witness testified "we felt it would be best to...not make an adjustment in my section regarding this particular item." (RT 19: 1510.) Supposedly, DRA's overall requested downward adjustment for labor costs proposed in Exhibit 107 (already discussed in an earlier section) would be all of DRA's recommended disallowance for PIP in the test year. We will briefly discuss DRA's recommended disallowance of capitalized PIP in the rate base section of this decision.

As to the specifics for Account 920, PG&E removed accrued incentive pay as recorded in 1990 from the forecast of Account 920 in the test year, spreading a PIP adjustment across all expense accounts as a percentage of labor in each account. PG&E believes this better reflects PIP as a portion of TCC and also better reflects the true cost of labor associated with various utility activities. In no way did PG&E intend to indicate that it felt PIP costs were not appropriate for recovery from ratepayers. (Exhibit 221.)

PG&E's removal of 1990 MIP costs was based on specific data: a journal entry showing officers' incentive pay and a specific subaccount in Account 920 where the MIP had been booked (Exhibit 221, p. 3-10). PG&E states that DRA's attempt to remove these MIP costs was done in a Byzantine fashion. PG&E points out that rather than examine specific 1990 base year data, DRA looked at the growth in Accounts 920 and 921 between 1988 and 1989 and concluded that those accounts grew more rapidly than ever due much if not all to PG&E's management incentive plan. DRA went on to conclude that both accounts should be reduced by the full increase between 1988 and 1989 in order to adjust the base year for test year analysis. (Exhibit 102, p. 9C-9.) PG&E points out that the obvious problem with using 1989 data to adjust the base year is the base year is not 1989, it is 1990. PG&E produced an exhibit that indicated a decrease in recorded incentive pay from 1989 to 1990 of $3.5 million. Additionally, PG&E points out that roughly $3.6 million in 1990 was direct Diablo Canyon incentive pay which was already removed from 1990 base year costs as part of the Diablo Canyon segregation process. PG&E concludes therefore that DRA's approach not only fails to reflect the decline in incentive pay between 1989 and 1990, it also double-counts the reduction for Diablo Canyon incentive pay already taken as part of Diablo Canyon segregation process.

We concur with PG&E that DRA has incorrectly analyzed Account 920 specifically and the PIP program overall. We fail to understand why DRA chose to approach this issue in this account in the manner in which it did. It was a confusing presentation. We will adopt PG&E's estimates for PIP expenses for Account 920. We agree with PG&E that it was appropriate to spread PIP costs among other labor accounts. And we find in this proceeding that the PIP program as PG&E has designed it is an appropriate part of the total cash compensation which we have already found to be reasonable.

### 9.2.3 Equal Opportunity Purchasing Program (EOPP)

All outstanding issues relating to the EOPP between PG&E and the CACD auditors[5] were presented in the September 15, 1992 Update Exhibit. (Exhibit 237.) There the company's revised EOPP estimates for several accounts were agreed to by staff. DRA in this proceeding is relying on CACD's review of this area. Overall, an agreement was reached to reduce the company's original 1993 EOPP costs by $1,551,000. This includes a $573,000 decrease to Account 920. In addition for Accounts 921 and 923 there were agreed upon reductions of $613,000 and $365,000, respectively. Even though we are discussing Account 920 here we will incorporate these other reductions for the other A&G accounts without mentioning them again in the text of this decision.

### 9.2.4 Family Benefits Coordinator Position

PG&E views this dispute with DRA regarding the appropriateness of ratepayer funding for a family benefits coordinator position to be a $35,000 difference for the Electric Department. The major role of this staffing position is to serve the PG&E-sponsored child care center on-site at company headquarters, 77 Beale Street, San Francisco. DRA believes its

5 CACD auditors took the lead on the EOPP review in this GRC rather than DRA staff.

exclusion of this position for ratemaking purposes is consistent with its recommendations regarding ratepayer funding and subsidy of the child care center generally. That issue will be discussed in greater detail in Account 921 and the rate base section. PG&E makes the argument that this position goes beyond the duties of coordinating the child care center and include the development of family-oriented benefit programs for elder dependents as well as for children and other members of the family. PG&E argues that this position clearly provides employee-related services which are a legitimate human resources cost for which DRA has given no reason for exclusion other than its association with the child care center. PG&E argues that the human resources challenges it will face in the 1990s and beyond justify that this new cost be recovered from ratepayers.

We disagree. We find DRA's arguments persuasive that this kind of position should not be funded by ratepayers. We note that we have been quite reasonable in our overall acceptance of PG&E's compensation and human resources goals. However, there are limits to such reasonableness. Within the dollars we have already authorized for compensation we believe PG&E can pursue such a position if it chooses to do so. If not, PG&E has the option of allowing the shareholders to fund such a position on the grounds that the benefits received from a happy workforce do in fact benefit shareholders. Our reasoning for the rejection of this position along with the child care center issues will be explained in another section in greater detail, in an effort to avoid repetitiveness.

## 9.3 Account 921--Office Supplies and Expenses

PG&E and DRA are roughly $14.5 million apart in their estimates for the Electric Department portion of Account 921. The other differences are due once again to how to use the Diablo Canyon Use Studies, disputes regarding incentive pay (MIP/PIP), and finally a subsidy to PG&E's child care center.

9.3.1 Diablo Canyon Use Studies

The arguments of the parties for what allocation factor to use for Diablo Canyon are the same arguments that have already been discussed fairly extensively for Account 920. Once again DRA's simplistic method of allocating 15.8% above test year expenses for Account 921 is unreasonable. Therefore we adopt the same method as we adopted for Account 920, that proposed by PG&E, for Account 921 for Diablo Canyon allocation.

9.3.2 Incentive Pay Adjustment

DRA made an adjustment based on 1989 data, similar to its Account 920 adjustment, to remove the PIP costs from Account 921, based on its assumption that there must be some incentive pay in Account 921 because Account 921 "tracks" Account 920. (Exhibit 102, p. 9C-8.) DRA has come to the conclusion that the increases and decreases in expenses for these two accounts are directly linked.

PG&E states that DRA has made the same errors in analyzing Account 921 as it did in Account 920 plus an additional error. Once again, PG&E points out the inappropriateness of DRA making an adjustment based on 1989 data instead of basing its adjustment on specific 1990 base year data. PG&E points out, however, that in this account the error is more egregious because no incentive plan payments (MIP) were booked in Account 921 in 1990. PG&E does not deny that there may be some relationship between some of the costs recorded in Account 920 and costs recorded in Account 921; however, such a relationship is not necessarily direct or proportional. Further, PG&E points out that the increase in Account 921 that DRA relies on for its recommendation between 1988 and 1989 was clearly due to things other than incentive pay.

In its rebuttal testimony, PG&E showed that the two detailed costs elements used in PG&E's accounting system to record the MIP and PIP did not appear in this subaccount and the costs booked to this subaccount of Account 921 could be shown to be things other than payments under either these incentive programs. PG&E urges the Commission to reject DRA's tracking adjustment for Account 921.

Once again we concur with PG&E on this issue of incentive pay. PG&E has made its case that there are no PIP dollars in Account 921. DRA's arguments are at best convoluted, and the link between Accounts 920 and 921 for incentive pay has not been shown. Therefore, we reject DRA's proposed $22 million adjustment for Account 921.

### 9.3.3 Child Care Center Funding

The dispute for Account 921 purposes centers on an operational subsidy to PG&E's employee child care center. DRA's recommended disallowance for this account is $290,000 on a total company basis. The Electric Department disallowance is $165,000.

PG&E would like to include in Account 921 the portion of the annual operational costs of its child care center not recovered from users of the child care center. DRA recommends removal of these costs. PG&E contends that there are ratepayer benefits that derive from the running of an on-site child care center. PG&E argues that these benefits include the ability to attract and retain employees. PG&E states that through the 1990s the business environment within which it operates will have many demographic changes. Included in these is an increased participation of women and minorities in the workforce and changing family patterns. PG&E states that by the year 2000, 80% of women between the ages of 25 and 44 will be in the workforce. PG&E believes that it will use this labor pool more heavily than most companies because the current average age of PG&E employees is older than the national employee average. (Exhibit 6.)

PG&E has been congratulated by child care advocates for sponsoring a center that emphasize quality. (RT 18:1342-1343.) PG&E also cites that many other businesses have opened on-site child care centers in recent years. PG&E claims that the average subsidy of these child care centers by the businesses sponsoring them is 40%. PG&E argues that its own operating subsidy is comparable to those of other companies.

DRA, on the other hand, does not dispute that PG&E's child care center is a value to PG&E as an entity. The issue is whether ratepayers should subsidize this project. DRA points out that PG&E's argument that it would be unable to attract qualified employees at a future date is somewhat diminished by the fact this child care center only has slots for some 68 children. It is also unclear from the record, in DRA's view, that the child care center will have such an impact on retaining and attracting competent personnel. DRA argues that PG&E has failed to show that the child care center will provide direct benefits to ratepayers. DRA contends that this was the standard set forth in its last GRC decision. (34 CPUC2d 199, 266-268.)

We concur with DRA on this issue. We note that PG&E has been rather vague as to both the improved productivity and employee retention that they claim will follow from this child care center. At this point there is no plan in place to track an improvement in employee productivity. (RT 18:1371.) We note that a very small group of employees will receive this benefit. The cost per child of the subsidy is extremely significant. During questioning by the ALJ, PG&E's witness conceded that public relations benefits and goodwill to the company derive from the opening of such a child care center. (Tr. 18:1367.)

Likewise we find the statistics indicating that other companies subsidize on-site child care 40% to be unpersuasive to the issue of whether PG&E's ratepayers should provide that subsidy. There is no information presented that these other companies in fact passed all of this subsidy on directly to customers. Likewise we note that PG&E was vague as to whether it had looked into various options that could reduce the operational cost of the child care center, e.g., having it run by a nonprofit company that will be perhaps eligible for a United Way funding, seeking employee contributions, and other fundraising efforts within the company. Further, as was stated by a child care advocacy group in a letter to PG&E that was quoted in the record, PG&E has chosen to provide a high quality child care center. That choice to provide a top-of-the-line child care center is one that PG&E is entitled to make. However, it does not necessarily follow that PG&E's ratepayers should subsidize an effort to be a top-of-line model.

Finally, we find that ratepayers are already providing an operational subsidy to the child care center by providing the space for the center at no rental fee within PG&E's headquarters building at 77 Beale Street in downtown San Francisco. When questioned as what the rental value of that space would be, PG&E's witness that it would be somewhere around $17 a square foot per annum. Given the child care center is 9,000 square feet, this equals an operating subsidy of over $150,000 a year. We believe this is more than adequate subsidy by PG&E's ratepayers of its child care center which will be a major public relations asset. We encourage PG&E to continue with its project, but not at ratepayers' expense. We note that perhaps if the shareholders pay for this project, the company will find a way to streamline its expenses and operations.

### 9.4 Account 922--A&G Expenses Transferred Credit

Account 922 is credited with the expenses recorded in Accounts 920 and 921 which are transferred to CWIP. PG&E and DRA agree on the method to be used to determine the Account 922 credit. Both agree the allocation to construction credit represented by Account 922 should be developed by multiplying the total of Accounts 920 and 921 by a factor of 18.2%. Therefore we will apply that factor of 18.2% to the totals we approved for Accounts 920 and 921 in today's decision.

## 9.5 Account 923--Outside Services Employed

PG&E and DRA have differences outstanding on three areas of this account. The first difference of $3,467,000 is due to DRA's exclusion of PG&E's request for increased outside legal services; $1,596,000 is due to DRA's exclusion of PG&E's request for outside legal services specifically related to third-party litigation; and finally $16,000 is recommended for exclusion by DRA for software and consultant services for use in its financial planning and analysis department.

### 9.5.1 Outside Legal Services

PG&E's estimate for the Electric Department portion of Account 923 exceeds DRA's estimate by roughly $5.1 million. $3.4 million of this exclusion relates to PG&E's request for increased outside legal services. PG&E arrives at its requested increase based on a three-year trend in outside legal costs. DRA, on the other hand, believes that expenses for legal services, whether in-house or outside, should be maintained at 1990 levels.

The debate between the parties focuses on (1) whether increased legal demands have been placed on PG&E, and (2) whether or not PG&E's current staff of 77 lawyers should be able to absorb the increase if it exists. Obviously, it is PG&E's burden to prove that such an increase is needed. PG&E's original showing on this issue was so weak as to require the ALJ to request additional information on the subject in rebuttal hearings. PG&E's argument focuses on a belief that industry restructuring and increased regulatory initiatives have resulted in a more complex and greater number of proceedings. At the same time, PG&E contends that its regular legal activity is either constant or growing. PG&E has determined that it is most efficient way to have its in-house counsel spend more of its time on regulatory matters and to hire outside counsel to handle general litigation. PG&E notes that its request, based on a three-year trend, is substantially less than what would have resulted from a five-year trend. The focus of the debate between PG&E and DRA is not on the accuracy of the trending, but rather on whether PG&E has proved that the supposedly increased volume of legal work really cannot be handled by the large in-house staff it currently maintains.

PG&E believes many current Commission proceedings have increased the demands placed on its law department. However, the tables provided in their rebuttal testimony do not really indicate how busy any particular group of attorneys really is in the legal department. (Exhibit 221, Chapter 3.) While there are certainly some new dockets at the Commission which PG&E must participate in, there are others that have closed. A mere listing of the number of proceedings does not necessarily mean there needs to be an increased number of attorneys working on those cases. In fact, PG&E claims that it is attempting to build internal expertise in specialized areas unique to the utility industry. This internal expertise should result in fewer attorneys assigned to a particular case. The data provided by PG&E as to the actual caseloads and work of its legal department cannot lead us to the conclusion that the proposed increase from 1990 levels is justified. One of our reasons for approving the compensation policy of PG&E is our expectation of productivity from PG&E's employees. We note that in these recessionary times there is an abundance of attorneys with excellent qualifications on the market. PG&E's legal staff should be of the highest quality given the marketplace in which it operates. Therefore, we expect its staff at current levels to be able to handle any increased caseload if it arises. Several of the cases mentioned by PG&E will not necessarily continue on for the whole cycle of this GRC. Therefore, we concur with DRA on this issue of outside legal services and deny PG&E its requested increase. We agree that PG&E failed to produce the necessary evidence to convince us that these increased demands, if in fact they exist, could not be met by current resources.

### 9.5.2 Third-Party Litigation Expenses

While this area actually is a part of outside legal services, it was treated separately in this case by both PG&E and DRA. For purposes of the Electric Department portion of Account 923, the disagreement between the parties for this item is $1.6 million.

DRA contends that this issue typifies PG&E's casual attitude toward ratepayer money. PG&E points out that it has requested this money to fund what PG&E describes only as "third-party litigation." In DRA's original prepared testimony, DRA withheld its analysis of this item because of a dispute over confidentiality. DRA objected to PG&E's request that this subject area be referred to only as third-party litigation. However, the ALJ ruled that DRA's report could be released as written and any references to the subject area would use the term third-party litigation. DRA contends that PG&E's argument in favor of funding of this third-party litigation is even more indefinite than those offered in support of outside legal services generally. DRA argues that PG&E was unable, or unwilling, to provide any details of what steps have already been taken to pursue this third-party litigation, how long it would take, who will handle it, or how the funds would actually be spent. DRA concludes that PG&E does not know how its current legal budget is being spent or where the additional monies would in fact go.

PG&E counters that this request is in specific reaction to federal, state, and local regulations governing hazardous waste. PG&E is currently pursuing the investigation, improvement, and possible mitigation of hazardous waste contamination at many of its former operating sites. However, as also dictated by federal, state, and local legislation, other parties may share the liability for cleanup costs. Therefore PG&E is seeking to defray ratepayer expenditures by recovering these costs from the appropriate parties. PG&E contends that to effectively do so, outside legal counsel and other expert staff are needed in this area.

In this specific situation, PG&E has identified a new category of increasing legal demands for which it believes that retaining outside counsel makes the most sense. Given the specialized nature of this litigation, PG&E believes that the need for outside counsel and experts in this area is justified. PG&E discounts DRA's contention that an increase in expenses for this environmental third-party litigation should be disallowed because there is no guarantee that PG&E will win. (Exhibit 132.) PG&E points out that this statement displays a failure to understand the nature of legal proceedings. PG&E states that no litigation can be entered into with a 100% probability of winning. Indeed, litigation may be resolved through settlement between parties. PG&E points out that legal costs are associated with case preparation and negotiations in order to reach any potential settlements. PG&E argues that by pursuing these third parties through litigation, PG&E can defray ratepayer responsibility for some of these costs. PG&E has suggested that any recovery could be credited as it is received directly against the memorandum account either as a refund or as an offset to future ratepayers. Therefore PG&E concludes that funding of third-party litigation could lead to lower rates and should be allowed as a reasonable expense.

On this issue we will grant PG&E's requested increase for third-party litigation. We note that the nature of the litigation made it somewhat improvident for PG&E to provide access to much detail. However, we are aware, based on our concerns with hazardous waste cleanups and the pending memorandum accounts generally, how important it is for PG&E and other utilities to aggressively pursue payments by other responsible parties. It would be difficult for us to order PG&E to aggressively pursue monies from other third parties if we did not in fact provide it with the resources to do so. Likewise, we agree with PG&E that this is an area where its own in-house staff does not necessarily have an expertise and frankly could probably not develop one in an adequate time frame.

We instruct PG&E to aggressively pursue this area of third-party litigation to assist in hazardous waste cleanup payments. We do intend that any money that is received in settlements or as the result of judgments shall in fact return to the ratepayers. We also warn PG&E that we expect it to get good value for the dollars spent in this area. As we noted in the prior section, in these recessionary times, there is great opportunity to negotiate strongly and diligently with outside counsel and expert witnesses for reasonable fee structures. We approve PG&E's request for third-party litigation expenses.

### 9.5.3 Investor Relations Expenses

This item relates to PG&E's cost of maintaining investor lists. PG&E justifies its request by stating that in order to raise capital in financial markets, PG&E must attract and retain investors. The requested expense increases are for software and consultant services needed to identify and maintain investors and institutions who can be relied on as purchasers of securities and sources of capital. PG&E hopes to attract investors capable of providing low cost sources of capital. PG&E asserts that this expense benefits both PG&E shareholders and ratepayers. PG&E denies the proposition that there is a distinct separation between what is good for ratepayers and what is good for shareholders in terms of operating the utility in the most efficient and effective manner. PG&E contends that access to capital on reasonable terms clearly benefits ratepayers. The Electric Department portion of this item is $16,000.

DRA recommends that these expenses not be allowed. DRA points out that the last GRC for PG&E stated that a utility must prove that ratepayers derive a direct benefit from the expenses they are asked to bear. While the benefit need not be quantifiable, it must be direct and tangible. (34 CPUC2d 199, 266-268.) DRA contends that the direct benefit for maintaining investor lists is clearly with the shareholders and that any benefit that comes to the ratepayers is clearly two or three steps removed from the expenditure of the funds.

We agree with DRA on this issue. We note that the overall dollars involved are very modest in the big picture of this GRC. In addition, as PG&E has acknowledged, it is a large, well-known company, and it is able to employ a number of means to attract investor money. It seems clear to us that the benefits to the shareholders for this line item outweigh any indirect benefit which the ratepayers accrue. Likewise, we note that the overall results of this GRC should do much for PG&E by way of attracting low-cost capital.

9.6 Account 926--Employee Pensions and Benefits

There are some substantial disagreements between PG&E and DRA for the Electric Department portion of Account 926. PG&E's estimate exceeds DRA's by some $47 million. The differences are as follows: $50,621,000 due to differences in estimates for post-retirement medical benefits for active employees; negative $19,087,000 due to differences in medical escalation; $4,371,000 due to allocation differences; $4,707,000 due to different input amounts for employee growth calculations; $2,932,000 due to methodology differences for employee growth; $2,821,000 due to DRA's exclusion of PG&E's request for funding for its blueprint for learning program; $604,000 for differences in estimates for post-retirement group life benefits for active employees; and finally $407,000 due to differences in estimates for medical benefits.

At the outset we note that our decision in this case related to post-retirement benefits other than pensions (PBOPs) will be consistent and bound by decisions in I.90-07-037. We note that a Phase II proposed decision in that case was mailed on

October 5, 1992. We will rely on the findings of that proposed decision for purposes of the proposed decision in this GRC.

9.6.1 Medical Benefits Expenses

It should be of no surprise to anyone who reads the newspapers that the issue of medical benefits expenses is controversial in this proceeding. PG&E described in detail its plans used to provide medical coverage, including self-funded medical plans administered by Blue Cross and Blue Shield and 12 separate health maintenance organizations (HMOs). In order to ensure cost-effective operation of these plans, PG&E has undertaken a number of medical costs containment efforts, including reducing medical costs by designing and administering the self-funded plans in a cost-effective manner, developing state-of-the-art medical cost management practices, and influencing employees to adopt a healthier lifestyle. (Exhibit 6, Chapter 10B.)

Effective January 1993, the beginning of the test year, PG&E will introduce a point of service managed care plan providing a network of service providers, with coverage reduced significantly for services obtained outside the network. All of these efforts are designed in part to help offset identifiable trends in medical costs which lead to cost increases at a rate faster than general inflation.

PG&E developed Test Year 1993 costs based on aggregate 1990 claims escalated by the medical cost trends developed by William H. Mercer, Inc. (Exhibit 6, Chapter 10B.) These cost trends reflect all of the expected savings from PG&E's various cost containment measures. The resulting initial medical cost trend increase of 14.5%, <u>before adjustments</u>, was applied to self-funded plan costs, and HMO costs were escalated at 12% based on projected increases in Kaiser plan costs, since Kaiser members represent 72% of PG&E HMO participants.

The resulting estimated self-funded plan costs were reduced by $1.7 million to reflect estimated savings from new cost containment measures implemented in 1991; and by another 3%, or approximately $2.4 million in 1993, to reflect cost savings from the point of service managed care plan. PG&E concludes that the combined savings from these plan changes and their impact on the overall trend result in total estimated savings of $7.3 million in 1993, $10.6 million in 1994, and $14.6 million in 1995. (Exhibit 6, Chapter 10B.)

DRA contends that these trends developed by PG&E are based on national trends. DRA states that it believes the trends should be based solely on PG&E's experience in health care costs. DRA states that in the last five years there has been a 6.8% average annual percentage charge experienced by PG&E. DRA recommends that a rate of 9.9% be used for medical inflation rate. (Exhibit 102, Chapter 9A.)

PG&E disputes DRA's assertion that there has been a 6.8% annual increase in medical costs for the last five years. PG&E points out that this calculation assumes only a 1% medical cost increase between 1990 and 1991. PG&E states that the calculation supporting this percentage wrongly excluded pay-as-you-go retiree medical costs, thus understating the actual 1991 percentage cost increase of greater than 16%. (RT 19:1452-43.)

PG&E argues that its medical cost escalation trend was developed for PG&E by separating the major components of cost, and escalating those components based on the best available data, including PG&E's specific experience. This trend incorporates both current plan design and changes anticipated in 1991 and 1993 which lower the forecasted medical costs below what they would have been without such cost controls. Thus, PG&E concludes, that its medical costs escalation trend is reasonable and more appropriate over the forecasted period.

We agree with PG&E that it has justified its proposed medical escalation trend for Test Year 1993 more than adequately. We admit we are still confused by DRA's arguments in this area.

Finally, we note that PG&E has requested an additional escalation factor for the attrition years for medical expenses. While that issue will be addressed in the attrition section of this decision, it is all the more important that appropriate medical costs be adopted for 1993 Test Year. By adopting PG&E's medical escalation trends for Test Year 1993, we are presenting a realistic picture of what should occur in that year.

9.6.2 Pre-funding of Post-Retirement Medical Benefits (PBOPs)

We must begin by stating our belief that much of the time and discussion spent on the topic of PBOPS was due in large part to DRA's dissatisfaction with the outcome of our Phase I decision in I.90-07-037, the PBOPs proceeding for all utilities. We note simply because DRA loses an issue in that proceeding does not necessarily mean it will win the issue by attempting to relitigate it in this case. Quite the contrary, we admonish DRA for the time it has wasted in this proceeding relitigating settled issues. We intend for this decision to be consistent with our findings in the PBOPs investigation, both Phase I and Phase II decisions. We were presented with no testimony in this proceeding to persuade us that we should do differently. In fact, given the record developed by DRA in this proceeding, we are more confident than ever that nothing in this proceeding changes our adopted position in the PBOPs proceeding.

In fact, DRA's position in this GRC is greatly eroded by its insistence on a misconception about the status of Diablo Canyon. DRA's witness continually referred to Diablo Canyon as a nonregulated entity or part of nonregulated operations of PG&E. When queried on this theory by the ALJ, DRA's witness could point to no Commission decision that has so described Diablo Canyon as nonregulated. This kind of characterization in the face of all the facts leads us to greatly question the credibility of the witness on this and other areas. The fact is that Diablo Canyon is in fact regulated, albeit nontraditionally. DRA's project manager was at a loss to explain where the PBOPs witness developed this opinion.

As to PG&E's true nonregulated affiliates or subsidies, PG&E provided concrete evidence, in the form of specific language in trust agreements, to establish that no such nonregulated subsidiary or affiliate can participate in the Voluntary Employee Benefit Association (VEBA) trust established by PG&E. (Exhibit 54.)

Correctly, PG&E is requesting rate recovery for post-retirement benefit costs on a basis consistent with PG&E's filing in Phase 2 of the OII, acknowledging that its rate recovery should be amended as necessary to be consistent with the upcoming Phase 2 decision in I.90-07-037. We once again reiterate that pre-funding of PBOPs expenses alleviates problems of intergenerational inequity, and is in the ratepayers' best long-term interest.

Therefore, we approve PG&E's proposal for funding of its PBOPs expenses in this GRC to be consistent with the ratemaking approach adopted for PBOP in D.92-12-015 (I.90-07-037). We will incorporate the total company numbers of $161,898,000 for Post-Retirement Medical and $18,749,000 for Group Life, as provided by PG&E in its reply comments to the proposed decision in this GRC.

However, we recognize that these amounts are subject to CACD approval by January 1, 1993 as ordered in Ordering Paragraph 1 of D.92-12-015. Therefore, we will make the revenue requirement associated with these amounts subject to refund to the extent that they exceed the PBOP cost level corresponding to the method approved by CACD. In the event that CACD determines that such refund is required, PG&E should file an advice letter to adjust its authorized base rate revenue by January 30, 1993.

Finally, we note that this area was in fact a large portion of DRA's overall reduction of PG&E's revenue requirement in this proceeding. Given DRA's limited resources, it seems improvident for it to continue to pursue issues in the GRC proceeding that it has lost in other forums.

9.6.3 Post-Retirement Life Insurance

Once again, this issue centers on DRA's refusal to accept that we have authorized pre-funding of certain post-retirement benefits. Only in DRA's mind has PG&E not complied with the ordering paragraphs of the First Interim Order in I.90-07-037 DRA's recommended disallowance is $1,188,000. PG&E points out that once again DRA's phantom nonregulated Diablo Canyon theory has no place in the real world. We reiterate that Diablo Canyon is in fact a regulated entity, not unregulated. For the same reasons described in the prior section, we reject DRA's position on this issue.

9.6.4 Group Life Insurance and Long-Term Disability Plans

In its exhibit, DRA states that PG&E used certain adjustments to 1990 recorded data which DRA opposes. DRA states that even though PG&E provided data on the past five years of expenses for these plans, PG&E could not identify which portions of the expenses for those years were due to the adjustments. Since PG&E's data was incomplete, DRA was unable to track previous adjustments or compare them to adjustments now claimed. In a situation such as this one, DRA recommends that when adjustments greater than 5% are made to base year data, then those same adjustments must also be made to data from the previous four years. DRA argues that this method will ensure some continuity for comparison and forecasting purposes. (Exhibit 102, Chapter 9A.)

PG&E correctly points out in its reply brief that there is no disallowance connected with this recommendation by DRA. Accordingly, we will adopt PG&E's numbers for group life insurance and long-term disability plans.

9.6.5 Employee Growth Calculations

PG&E and DRA seemingly agree the employee growth factor used to develop amounts for Account 926 incorporated in this decision should be based on a ratio of 1993 Test Year labor to 1990 base year labor as long as that labor is on a comparable basis. The differences that exist between PG&E and DRA are in part caused by different estimated amounts of Test Year 1993 labor. The figure we have decided in this decision for test year labor is the same number that should be used in the final calculation for Account 926. PG&E explained in detail its recommended calculation for an employee growth factor. DRA never provided any guidance on the issue.

We adopt PG&E's employee growth factor calculation not only because DRA failed to give us any guidance, but because PG&E's calculation is clearly logical and meritorious on its own.

9.6.6 Blueprint for Learning Expenses

On a companywide basis PG&E is requesting nearly $4.9 million for a new training program called "Blueprint for Learning." The Electric Department portion of this is $2.8 million. DRA recommends a complete exclusion of this expense.

DRA contends that PG&E has failed to prove that this multi-million dollar program would be a direct benefit to ratepayers. DRA refers to PG&E's descriptions of this program as "pages and pages of oblique promises and meaningless jargon" that do nothing to show that ratepayers would derive any benefit from this expensive and possibly duplicative program. (DRA opening brief p. 35.)

PG&E describes its Blueprint for Learning as a conceptual framework to assist existing training at PG&E and to identify future training needs, its primary strategy being to provide quality training for the 1990s in a timely and cost-effective way. (Exhibit 221.) As justification for this program, PG&E once again points to its belief that its operating environment will undergo significant changes throughout the 1990s. Increasing competition, greater customer expectations, heightened environmental concerns, rapidly evolving technology, and increasing diversity among employees and customers alike will be some of these changes which PG&E will have to deal with. PG&E believes the complexity of most jobs will increase while at the same time the supply of qualified labor will decrease. Once again PG&E points out that it will be more greatly affected than other businesses since its average employee age is higher than the national average. PG&E believes that the net effect of all these changes will be an increased need for quality training and education. PG&E does believe that its current education and training programs have adequately served the company up until now, but a changing world will require changes to its employee training and education. PG&E also asserts that the Blueprint for Learning will result in avoided future cost.

We concur with DRA's conclusions that PG&E has not adequately shown that there is a need for this program separate from its on-going training that is a part of its day-to-day operations. Much of PG&E's arguments in favor of this program are superficial and glib. We must once again note that one of our justifications for accepting PG&E's compensation policy is in fact to allow it to be able to attract qualified workers. At the same time, it should not be necessary to have such an expensive training program. We also note that the details of this Blueprint for Learning were not sufficiently explained by PG&E. Therefore we find that PG&E has failed to make an affirmative showing to justify the increased expenditures requested for this program. We will adopt DRA's recommended disallowance for the Blueprint for Learning program.

### 9.7 Account 930.2--Miscellaneous and General Expenses

PG&E's estimate for the Electric Department portion of Account 930.2 exceeds DRA's estimate by roughly $11.2 million. Slightly over $10 million of this difference is due to a difference in estimates for RD&D. Those difference would be discussed in the RD&D section of this brief. The remaining difference of slightly over $1 million is made up of the following differences: $844,000 due to differences in estimates for bank line of credit fees; $149,000 due to DRA's exclusion of PG&E's request for dues specifically related to legislative policy research, regulatory advocacy, and regulated research functions of the Edison Electric Institute (EEI); $70;000 due to DRA's exclusion of subscriptions and dues associated with PG&E's membership in the Conference Board, the US Business Roundtable, the California Roundtable, and Federated Employers of the Bay Area. (Exhibit 235, Comparison Exhibit, p. 3-71.)

9.7.1 Line of Credit Fees

PG&E predicts that its line of credit fees will increase on a total company basis of $1.25 million ($844,000 for the Electric Department). DRA recommends that this entire amount be disallowed. DRA bases its disallowance recommendation on the fact that PG&E was unable to provide any documentation from a banking institution to show what the new commitment rate would be. DRA argues that because PG&E cannot show with certainty with the new rates would be, it has failed its burden of proof to obtain an increase in this area.

PG&E counters this argument by stating that definitive data on line of credit fees are simply not available. However, PG&E points to the fact other evidence makes it reasonable to expect that during the test year line of credit fees will increase. PG&E believes it has met its burden of proof from a combination of different inferences.

First, current commitment fee contracts will expire in 1993. PG&E believes that the reluctance of banks to commit at this time to a definite rate suggests that they certainly will not entertain keeping the rate as it currently is. PG&E believes that current indications are that line of credit fees will increase from the present 0.125% to 0.25% of the available credit per year. (RT 18:1337-1338.) PG&E points out that the banks' unwillingness to extend the present agreements indicates that in fact the fees will go up.

Therefore, PG&E sees the question as how much will commitment fees increase? By analogy, during rebuttal hearings, PG&E provided documentation from banks providing bids for a letter of credit covering the company's workers' compensation liability. PG&E's analysis of those letters of credit indicated that the commitment fee rate being offered by the banks was actually higher than their estimate for line of credit fees in this GRC. Therefore PG&E believes that its estimate is in fact conservative. Finally, PG&E points out that no forecast can be guaranteed, but a forecast can be adequately substantiated. By its nature, a forecast can only be as good as the best information available.

We concur with PG&E that given the availability of information it has made a reasonable and in all probability a conservative estimate for its line of credit fees. Therefore we adopt PG&E's estimate for line of credit fees.

### 9.7.2 Dues and Subscriptions

PG&E and DRA disagree on several dues and subscription-related issues for various organizations to which PG&E belongs. Some of the differences only relate to a portion of the dues for a particular organization. PG&E has not requested ratepayer funding of all dues it pays.

PG&E argues that the portion of its dues for EEI which DRA recommends be disallowed are in fact legitimate and necessary activities. The activities in question are the legislative policy research, regulatory advocacy, and regulatory policy research function of EEI. PG&E argues that these activities benefit all parties concerned, both ratepayers and shareholders, by contributing knowledge and insight to policy makers about utilities, and by contributing the same to utilities about policy decisions which affect the industry. PG&E contends that both of these functions are performed collectively by EEI at a lower cost than individual utilities could achieve alone. PG&E argues that benefits accrue to ratepayers and shareholders by facilitating the efficient planning and smooth operation of the utility industry.

DRA points out that the same area was disallowed in PG&E's last GRC. In that case, the Commission found no evidence that the membership portion of the dues for these functions conferred any direct benefit on the ratepayers. DRA believes that PG&E has basically come up with no arguments showing that this is a direct benefit to ratepayers. DRA contends that PG&E is renewing the same request on the same basis of the same generalities that were found inadequate in its last GRC.

We stated in the last case:

> "Instead, the issue before us is whether the membership will accrue direct benefits to ratepayers. Such benefits need not always be quantifiable, but they must be tangible." ((1989) 34 CPUC2d 199, 268.)

In its brief, PG&E basically challenges our statement in the last GRC that the benefit must be direct to the ratepayers, calling it simplistic. PG&E believes that this line of thinking is based on an inappropriate division of ratepayer and shareholder benefits, as well as a confusion of what constitutes a direct and indirect benefit to ratepayers. PG&E argues that by stating that its membership in EEI has no direct benefit to ratepayers, that DRA is obscuring the real issue, which as PG&E sees it, is whether or not such membership is a legitimate corporate function which contributes to PG&E's ability to provide utility service at a reasonable cost. PG&E points out that when arguing the semantics of direct and indirect benefit in a rate case, the only true "direct" benefit to ratepayers of utility service is reliable and reasonably priced power, light, and heat. PG&E maintains that all such activities which contribute to the utility's ability to provide such service, such as legislative and regulatory research at issue here, are, by default, indirect benefits. (RT 18:1330.) In PG&E's opinion, this classification does not make them any less necessary or beneficial to ratepayers. Rather, in most cases, PG&E believes they are legitimate costs of service, which while not precisely quantifiable are perceivable in terms of avoided costs. PG&E contends that DRA's disallowance is not based on cost of service ratemaking. PG&E argues that in cost of service ratemaking, a legitimate cost of service must be included in rates.

While PG&E refers to DRA's position as being inappropriate, PG&E in effect is disputing our findings from the last GRC decision. DRA's position in this case comes directly from that, i.e., a requirement that there be a direct tangible benefit to ratepayers from the dues or subscription in question.

We find PG&E's arguments made in this GRC to be compelling enough to alter the position we took in the last GRC. The direct tangible benefit standard does seem to be one that would be difficult if not impossible to meet for certain subscription dues. We note that PG&E in fact did not request recovery for all business organizations to which it belongs. (Exhibit 6, Chapter 10A.) We agree with PG&E's analysis that we are still currently involved in cost of service regulation. We note that DRA acknowledges that EEI policy research may provide a necessary service, that service is not easily separable into ratepayer and shareholder impacts. We agree that the efficient and effective operation of the utility industry, which EEI research supports, is a joint benefit to ratepayers and shareholders alike. In fact, increased efficiency almost always translates into the reduction of unnecessary or avoidable costs, which if not so reduced would cost the ratepayers more in terms of rates. By not including these dues and subscription in rates, we are perhaps sending a signal to the company to not be a member of these organizations. That does not necessarily serve the ratepayers' interest. Therefore we will approve the portion of EEI dues which PG&E requested.

In addition to the EEI, DRA also requests disallowance of the issue dues of several organizations. We will address them one by one, though the arguments overall are very similar to those already discussed relating to EEI and will not be repeated again.

First, the Federated Employers of the Bay Area provide information to its member companies about human resources management, labor relations, and labor negotiations. PG&E points out that this organization conducts extensive research and publishes numerous reports and surveys about comparative personnel practices, salaries, wages, and labor contracts. It also provides consultation and education services on compensation and benefits issues. PG&E argues that to purchase such information, surveys, and studies on the outside would cost far more than the membership dues of $5,000. We agree and will allow PG&E to recover this membership cost in rates.

A second organization is the California Roundtable for which PG&E requests its dues be paid by ratepayers. PG&E argues that an improved business and political environment is a benefit to both the company and its ratepayers. The California Roundtable is involved with a number of different projects in California which are aimed at improving the environmental, business, and educational standards in the state. Among the issues promoted by the California Roundtable are improvements in California's public education system, workers' compensation reform and state water improvements. Any achievements in these areas promise improved operating conditions for PG&E. We agree with PG&E on this issue, rejecting DRA's argument that there are no direct benefits to ratepayers from membership in California Roundtable. Workers' compensation reform alone could save ratepayers millions of dollars per year. California Roundtable has a California focus that is very pertinent to PG&E and its ratepayers.

As to two other organizations in dispute, the Conference Board and the US Business Roundtable, we are less convinced that PG&E's ratepayers will accrue as many benefits from these memberships. In addition, these memberships may overlap with other groups in which PG&E already participates. Therefore we will disallow $19,000 for the Conference Board and $34,000 for the US Business Roundtable. PG&E's arguments for these two organizations are not as persuasive as the ones previously discussed.

## 9.8 Account 931--Rents

The only dispute between PG&E and DRA over this account relates once again to the proper allocation factor that should be used for Diablo Canyon separation. PG&E assigns a 4.87% of computer center expenses to Diablo Canyon using 1990 recorded data to calculate use factors based on DRA's request that use factors be updated between the NOI and the application. DRA assigns 6.09%[6] of computer center expenses to Diablo Canyon using 1989 recorded use data to calculate this factor. PG&E states that DRA is apparently arguing that the computer use factors should be as they appear in Diablo Canyon Use Study and not updated for newer data. PG&E goes on to suggest that DRA only makes this recommendation when for a particular item the Update results in a slight increase. To put it bluntly, PG&E argues that where there was a revision which increased the Diablo Canyon adjustment DRA accepted it. In this setting, for the computer center use charge, where the revision decreased the adjustment, DRA rejected PG&E's revision. PG&E argues that DRA's position is inconsistent and itself should be rejected. Further, PG&E notes that the overall result of updating the use charges results in an increase of $2 million in the Diablo Canyon portion of Account 931.

We agree with PG&E that DRA is inconsistent in its analysis on this issue. We note that DRA chose not to address this issue at all in its opening brief. Likewise there seems to be discrepancy between what DRA's recommendation is at this point in time. The Comparison Exhibit suggests that the allocation factor should be 5.86%, although in Exhibit 50, one could infer DRA's position was 6.09%. In light of this confusion, and because PG&E makes a reasonable argument for its recommendation, we will adopt PG&E's allocation factor of 4.87% of computer center expenses to Diablo Canyon for Account 931. Other issues in Account 931 are undisputed and therefore PG&E's numbers will be adopted.

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6 The Comparison Exhibit (Exhibit 235) shows DRA's number as 5.86%.

## 10. Taxes

### 10.1 Property Tax Settlement With the Board of Equalization

The parties agreed that testimony on property taxes should be deferred until the rebuttal phase of this proceeding in order to permit consideration of possible reductions resulting from a settlement with the State Board of Equalization which would reduce PG&E's property tax expenses for 1993 and beyond. (Exhibit 220.) DRA's witness supported the property tax settlement. (RT 53:4850-4851.) The revised property tax estimates, for Test Year 1993, are $110,165,000 and $30,265,000 for the Electric and Gas Departments, respectively. There is nearly a $12,000 reduction from the original application. PG&E points out that the revenue requirements reductions associated with the property tax settlement are slightly less than this amount because of offsetting income tax effects. PG&E, together with 26 other centrally assessed California utilities, entered into a property tax settlement agreement with the California counties, the State Board of Equalization, and the State Attorney General effective May 1, 1992. This settlement provides that PG&E's valuation for property tax purposes for the next eight years will be computed in accordance with the formulas, terms, and conditions contained in the agreement. (Exhibit 220.)

We concur with PG&E and DRA that this settlement is in the best interest of PG&E's ratepayers. We support PG&E's recommended implementation methodology. We find reasonable the property tax settlement described in Exhibit 220, including the resulting prospective reductions in property taxes and associated expenses for ratemaking purposes, and the waiver of claims for any period before the May 1, 1992 effective date of the settlement. Further, we find that the terms of the settlement have been incorporated into the property tax-related revenue determination for Test Year 1993 and attrition years 1994 and 1995. Given this, unless there is a change in the settlement, noninterest entries to the memorandum account set pursuant to I.92-03-052 are correctly zero for January 1993 and each month thereafter. (Exhibit 220.)

10.2 Payroll, Business, and Other Taxes

DRA and PG&E agree on the method of calculating payroll taxes, the applicable tax rates, and the appropriate taxable base per employee. The only remaining payroll tax difference between PG&E and DRA is due to differences in payroll (both labor growth and labor escalation which include DRA's proposed labor parity adjustment). We shall incorporate the adopted Electric Department payroll for the test year in the final determination of the test year payroll taxes.

10.3 Sales Tax Increase Adjustment

PG&E and DRA differ as to how to handle the California state sales tax increase that became effective July 1, 1991. California's basic sales tax rate increased from 4.75% to 6.0%. PG&E argues that because this sales tax increase is not captured in the recorded 1990 data, a specific and separate increase is necessary in the test year.

DRA argues that any statutory increase in sales taxes is already included in the escalated estimates for M&S and that adding sales tax would result in a double recovery. (Exhibit 102.) PG&E counters that this is not the case with the M&S (services) escalation rate. PG&E points out that the materials and services escalation rate is not tied to California-specific indices. The M&S escalation rate is based on national indices which would reflect the effect of the increase in the California sales tax only to the extent that California's economy is a percentage of the national economy. (RT 23:1923.)

We find PG&E's argument unpersuasive. The purpose of allowing for escalation is to capture such changes in sales tax.

## 10.4 Income Taxes

PG&E and DRA agree on the method for calculating federal and California income and deferred taxes. The differences between PG&E's and DRA's income tax expenses and deferred tax estimates are entirely due to differences in other revenue and cost estimates.

PG&E and DRA have agreed on a procedure for compliance with the treatment of investment tax credits required under the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA). In response to that act, a memorandum account was developed. PG&E requests that it be authorized to amortize TEFRA memorandum accounts as provided for by D.83-12-068 and D.86-12-095, by including the appropriate revenue requirements for 1993 and beyond until completely amortized over a six-year period. DRA has agreed to these amounts subject to revision to the short-term interest rate used to calculate carrying costs.

We will adopt the position that the parties have reached regarding income taxes and the TEFRA implications. We commend the parties for reaching agreement on this area.

# 11. Electric Plant and Rate Base

## 11.1 Overview

PG&E presented one witness to testify on electric plant and rate base, and the allocation of common plant to electric plant. DRA presented several witnesses to testify on these areas. We will express plant differences in this section as net of retirements rather than in gross dollars. The following table shows the differences between PG&E and DRA regarding electric rate base, excluding working cash differences. (Working cash will be discussed in a later section in this decision.)

Detail of Differences in Rate Base
Excluding Working Cash
(Thousands of Dollars)

| | PG&E Exceeds DRA |
|---|---|
| Weighted Average Electric Plant | |
| Electric Plant | 31,673 |
| Common Plant Allocation | 27,891 |
| Total | 59,564 |
| Materials and Supplies | 6,260 |
| Less Accumulated Deferred Taxes | 277 |
| Depreciation Reserve | -34,074 |
| Total Rate Base | 99,621 |

Finally, we note that since filing its original request for its entire plant estimates in the 1993 GRC application (for electric, gas, and common plant), PG&E has reduced its plant request by $218 million. The individual projects that comprise that amount are set forth in Exhibit 225. PG&E's plant witness testified that these reductions reflect the passage of time since the original filing in this case which results in circumstances having changed and many projects having been deferred or revised in scope or cancelled completely. This occurs in any general rate case. But PG&E points out the unusual circumstance here where a number of projects are no longer required in their original planned time frame because anticipated load growth has not occurred. PG&E believes this is a direct impact of the recession, conservation efforts, and increased asset utilization by PG&E. (RT 22:1723-1733.)

## 11.2 Project Amortization--Abandoned Plant

Project amortization shows up as a line item in Results of Operations, referring to the first year of a three-year amortization of abandoned project costs. PG&E originally requested some $66 million for recovery of electric abandoned project costs. Originally DRA disputed some $43 million related to Geysers Unit 21. During the Update hearings held in September, PG&E and DRA agreed on an appropriate way to handle the Geysers Unit 21 abandoned project recovery.

Since the opening hearings were held in this case, PG&E filed A.92-07-051 requesting the Commission to approve a settlement agreement that, among other things, includes the condition that UNOCAL makes a payment of $43 million to PG&E for the major portion of the Geyser 21 costs. PG&E agrees with DRA that ratepayers should not bear this $43 million cost if PG&E recovers it from UNOCAL. Originally, the company did not reduce its abandoned project request because of the uncertainty whether or not the Commission would approve the settlement agreement. Actually, only a procedural difference exist between the parties. PG&E requests that the Commission find that PG&E has not violated the Commission's criterion for a timely request for abandoned project recovery in the event that the Commission chooses not to approve the UNOCAL application (A.92-07-051). Therefore, in Update proceedings, PG&E reduced its request for abandoned project recovery of the Geysers 21 costs to the $931,000 that DRA agreed to in this GRC. Therefore, PG&E has resolved the remaining difference between DRA and PG&E on how to handle Geysers 21.

We appreciate PG&E's effort to resolve this issue. We will give PG&E the assurance that if the Commission does not approve A.92-07-051, then PG&E may raise its request in its next GRC for recovery of Geysers 21 costs.

A second issue related to abandoned plant was raised during the Update hearings in September. DRA and PG&E had agreed to a request of $15,844,000 of abandoned project costs for the California/Oregon Transmission (COT) project. PG&E, by the time of its Update hearings, had determined that it would seek recovery of a portion of these costs from the other COT project participants.

PG&E points out that it is unlikely that the outcome of this effort would be known by the time the Commission issues this decision. Therefore, in agreement with DRA, PG&E proposes that if it is successful in obtaining funds from the COT project participants, then an adjustment will be made to the ERAM balancing account at that time in order to flow any payments through to ratepayers. Both parties agree that this is a better approach than adjusting any recommendations for abandoned project recovery of COT costs in this proceeding.

We agree with PG&E and DRA that to make the adjustment in the ERAM account is a better approach. Therefore, given that the Geysers 21 issue has been resolved, there are no remaining issues of disagreement between PG&E and DRA for abandoned plant. As such, we find that PG&E has met our criteria for recovery of abandoned projects as has been set forth in prior Commission decisions. Those criteria include the following: (1) that the project ran its course during the period of unusual and protracted uncertainty, (2) that the project was reasonable throughout the project's duration in light of both the relevant uncertainties that then existed and of the alternatives for meeting the service needs of the customers, and (3) that the projects were cancelled promptly when conditions so warranted.

These criteria having been met, we find PG&E's current request for amortization of abandoned project costs shall be adopted.

## 11.3 Differences Between PG&E and DRA Regarding Electric Plant

Despite PG&E's reduction during hearings of $218 million in electric and other plant, PG&E and DRA disagree as to $31,676,000 for test year weighted average electric plant. The following table shows the areas of differences.

| | PG&E | DRA | PG&E Exceeds DRA |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| 1. R&D Wind Demonstration | 1,902 | 0 | 1,902 |
| 2. Hydroelectric Relicensing | 9,654 | 250 | 9,404 |
| 3. Breaker and Relay Replacement | 12,927 | 2,164 | 10,763 |
| 4. Transmission System Reinforcements | 10,001 | 5,661 | 4,340 |
| 5. Echo Lake Dam Stability | 4,555 | 1,244 | 3,311 |
| 6. Mokelumne Settlement Disallowance | 2,517 | 581 | 1,956 |
| Total Electric Plant Difference | 41,556 | 9,880 | 31,676 |

11.3.1 Research & Development (R&D) Wind Demonstration

PG&E has included the costs of a research demonstration project of advanced wind turbine technology in its plant estimate. DRA has recommended no funding for this project as a research demonstration because it believes that wind technology has advanced to the point where PG&E no longer needs to promote it. Since this really is a research and development issue, we will discuss it in detail in the section on RD&D. However, for purposes of this section, we will remove the dollars sought from electric rate base. These dollars as shown in the chart above are $1,902,000.

11.3.2 Hydroelectric Plant Relicensing

PG&E and DRA disagree as to whether it is appropriate to include the costs of relicensing eight of PG&E's hydroelectric powerhouses in its electric plant estimate. PG&E is seeking to relicense these plants before the Federal Energy Regulatory Commission (FERC). PG&E's costs for such an activity consist of studies, hearings, and answering inquiries prior to the award of the licenses to own and operate a hydroelectric plant. (Exhibit

235, p. 3-95.) The dispute between the parties is not over the amount of the costs PG&E has accrued in its relicensing efforts nor whether these costs were incurred unreasonably. The dispute focuses on whether these costs, prior to the actual receipt of a new license, should be placed in rate base now or rather, as DRA recommends, placed in an allowance for funds used during construction (AFUDC) for now, and having the dollars transferred to plant after the license is received from FERC.

DRA argues that relicensing costs should not be included in plant until the relicensing is successfully accomplished. DRA states that utility relicensing efforts prior to FERC approval are similar to construction work in progress, and should be treated as such for ratemaking purposes. DRA argues that ratepayers realize no benefit from the expenditure until the license is won. (Exhibit 103.) DRA's rate base witness succinctly set forth its reasons for AFUDC treatment of these relicensing efforts:

> "The basic reason for AFUDC treatment is to provide PG&E with the incentive to work efficiently toward hydroelectric relicensing. Work on relicensing should be properly prioritized and executed in a timely manner. A second reason is to place risk of failure on PG&E and to encourage sound management of relicensing projects. If all the risk is borne by ratepayers, PG&E would have no real incentive to manage such projects prudently. PG&E should exercise its best judgment and put forth its best efforts toward obtaining hydroelectric licenses. Allowing rate base treatment of relicensing expenditures places risk of failure on the ratepayers. Thirdly, ratepayers benefit only when the licenses are received and continued output from the generators is assured. Should PG&E fail to obtain the license, the ratepayer receives no benefit. The Commission has long used the criteria that rate base is treatment allowed only when the addition is used or useful." (Exhibit 170, pp. 1 and 2.)

PG&E counters that DRA has changed its position from the last GRC where these costs were allowed by the Commission. We note that PG&E gives no citation to the 1989 decision for that position. In any event, PG&E goes on to argue that ratepayers in fact received current benefits through PG&E's efforts of obtaining annual extensions to the hydroplant operating licenses, thereby allowing powerplants that are currently used and useful to remain in operation. PG&E believes that the ability to continue to operate the cheapest source of power PG&E has on its system through annual extensions to the license provides the substantial benefit to ratepayers while the relicensing activities are progressing. DRA disputes that all of these plants are operating on extensions. Some of the plants are operating on current license authority. (RT 22:1829-1830.) DRA does not believe it is appropriate to put the relicensing efforts in rate base today based on "the expectation that they will eventually receive a license." (RT 22:1830.) DRA points out that expectations of the future are not current benefits.

We agree with DRA as it has framed the issue in this case. We point out that DRA's AFUDC recommendation simply defers utility rate base treatment until relicensing actually occurs. At that time, the plants can and will be properly included in rate base. We agree with DRA that postponing the placement of these relicensing costs in rate base should give PG&E an additional incentive to put its best efforts into obtaining these licenses. We also note, as DRA has pointed out, that in the event the licenses are not received, the benefit to the ratepayers does not exist.

PG&E stated in its opening brief that in the event the Commission adopted DRA's position that DRA's numbers would still need to be recalculated. PG&E notes that DRA accepted PG&E's end-of-year plant estimates but those estimates included no AFUDC. PG&E argues that if AFUDC was included DRA's plant estimate for these two projects should have been increased. We instruct PG&E to provide in its comments on this proposed decision a proposal for what that increase should be. PG&E is free to place these comments in an appendix to its comments.

11.3.3 Breaker and Relay Replacement Program

PG&E has included $12,927,000 in its weighted average plant estimate for continuation of its breaker and relay replacement (BARR) program to replace obsolete transmission system protective equipment. DRA's estimate is some $10 million less, being $2,164,000 for its plant estimate. The difference between the parties is a disagreement as to what the appropriate level of spending for this program should be in Test Year 1993. The BARR program was set up as a three-phase program, each phase covering a three-year period. The phase in dispute is the third, and final phase of the distribution business unit's portion of the program covering the years 1992 through 1994. DRA argues that PG&E's spending in 1991 was only $1.29 million for this program and that its expected spending for 1992 was only $1.2 million. DRA argues that the increase for 1993 is excessive.

However, PG&E contends that DRA is confused on this issue. Pursuant to the ALJ's request, PG&E filed an exhibit setting forth the capital expenditures for this program from 1986 through 1991. (Exhibit 234.) Exhibit 234 shows that PG&E has consistently spent over $9 million per year on the BARR program since its inception in 1985. PG&E contends that DRA has confused capital expenditures in plant additions and the pattern of plant transfers as one phase of the BARR program is completed and the next phase begins. PG&E points out that DRA is wrong when it states that during 1991 PG&E spent $1.29 million for the BARR program. PG&E points out that that amount is the plant addition booked at the beginning of Phase 3 of BARR. The capital expenditures incurred in 1991 were $9.3 million. (Exhibit 234.)

Therefore, PG&E states that there is no large unexplained increase between 1991 and 1992; rather, there is a shift in the pattern of plant additions as planning and engineering is completed and installation begins. PG&E requests that this third and final phase of a ten-year program providing for the orderly replacement of these obsolete breakers be funded at the level it has requested in this GRC.

We agree with PG&E that what DRA sees as a huge increase for Test Year 1993 is more appropriately confusion on DRA's part as to what PG&E has actually spent on this program. In fact it was because of the confusion of the record that the ALJ requested the preparation of Exhibit 234. We will authorize the dollars requested for the BARR program. We note that it is scheduled to be completed in 1994 and look forward to our review of the dollar spent on this program in the next GRC.

### 11.3.4 Transmission System Seismic Reinforcements

PG&E and DRA disagree as to the appropriate level of spending for PG&E's program to replace seven 230 kV and twelve 500 kV circuit breakers vulnerable to seismic damage at six substations. Once again, the question is whether PG&E's request for Test Year 1993 funds is excessive. DRA contends that PG&E spent less than its budgeted amount on this program in 1991. DRA contends that even though the Commission's Safety Division's seismic report recommends this program, the Safety Division in no way deals with PG&E's ratemaking request for any programs. DRA notes that the Safety Division report does not mandate a particular time line for the circuit breaker replacement nor a budget. (Exhibit 74.)

PG&E argues that DRA's lower estimate is due mainly to DRA's incorrect calculation of the unit cost for substation circuit breakers to be replaced under the program. PG&E argues that DRA's calculation of unit cost is flawed because the witness used PG&E's 1993 plant estimate of some $12 million, which included only three years of expenditures on what is now a four-year project. PG&E did not show figures for 1994 in the application workpapers because they will occur after the test year. Dividing this dollar amount by the total number of breakers to be replaced for the entire four years resulted in an underestimated unit cost. The entire cost of the four-year project is estimated at $19 million. DRA's witness conceded that using the total four-year expenditure of $19 million rather than the $12 million estimate for the first three years of the program would have produced a higher unit cost.

We agree with PG&E and our own Safety Division that seismic safety is of great concern and an important effort for PG&E to pursue. DRA is correct that the safety report in and of itself does not necessitate the approval of the dollars sought by PG&E. However, we are persuaded by PG&E's arguments that the dollars requested here are an appropriate level of dollars for this program. Therefore we will authorize PG&E's requested dollars for the transmission seismic reinforcement program of roughly $10 million for electric plant for Test Year 1993.

11.3.5 Echo Lake Dam Project

PG&E's estimate for this project exceeds DRA's by $7.3 million. This was one of a couple of estimates that increased after the application was filed. The Echo Lake Dam stability project was originally estimated at a lower cost in PG&E's application. DRA has taken the position that that original estimate of $1.244 million be adopted while PG&E requests that a more current estimate of $4.555 million be used. In the spring of 1992 an alternative approach was selected to meet the safety concerns of the State Division of Dam Safety (SDDS) and FERC. The new construction method allows for extremely rapid installation at a far lower cost than traditional methods of dam construction because no concrete forms are required. This approach meets SDDS's and FERC's goal to have the construction completed by the winter of 1992. DRA's major objection to this project is the delay in receiving information, and secondly the request has increased since the original application. PG&E counters with the fact that since the application was filed PG&E has revised downward its plant estimates overall by $218 million. Therefore PG&E contends in fairness that DRA should be willing to accept increases in a few projects as well as millions of dollars of decreases. PG&E contends that the Echo Lake Dam project is required for the public safety and has been revised in scope to meet the requirements of regulatory agencies, while it still represents a low-cost alternative through the innovative use of new dam construction technology. PG&E urges that its estimate for this project should be adopted.

It is difficult to reject these arguments related to public safety. We note also that DRA chose not address this issue in its opening brief. However, the difference is still listed in the Comparison Exhibit. (Exhibit 235, p. 3-94.) We must admit that it would be tempting to adopt DRA's position that no item can increase after the application has been filed. However, we agree with PG&E that this seems unfair in light of all the decreases which we allow PG&E to make and frankly actively encourage. Obviously, we could not allow the overall application request to increase. But certainly we can allow certain items to fluctuate either upward or downward depending on the best available information that we have. We note that public safety is an expensive proposition. The failure of the Echo Lake Dam could potentially cost PG&E's ratepayers many more millions of dollars than that being requested here. Therefore we will authorize PG&E's request of $4,555,000 for its Echo Lake Dam stability project to be placed into electric plant.

### 11.3.6. The Mokelumne Settlement

The difference between DRA and PG&E on this issue is the result of a proposal by a DRA auditor and thus deals with recorded plant, not future plant estimates. PG&E included in its 1990 recorded intangible plant the cost of settling the Mokelumne project hydro relicensing dispute. DRA disputes the inclusion of $1.9 million of those settlement costs. D.90-12-123 adopted a settlement between PG&E and the City of Santa Clara regarding the dispute that originated in the 1970s. The issue then was whether municipal utilities should possess a preference over privately owned utilities in the relicensing of existing hydroelectric projects. The settlement agreement called for PG&E to pay $1 million to Santa Clara, to sell electricity to Santa Clara and to design for Santa Clara the grizzly hydroelectric facility.

The parties disagree as to whether D.90-12-123 determined whether or not the settlement was beneficial to ratepayers. The implication is that if the settlement is beneficial to ratepayers, ratepayers should then pay the costs of the settlement.

Shortly before the Update hearings, the situation changed. On September 2, 1992, we issued D.92-09-022, granting PG&E's petition for modification of the original decision in the Mokelumne settlement. Finding of Fact 8 was revised as follows:

> "PG&E's analysis of benefits to ratepayers under various scenarios indicates that benefits are highest under the provisions of the settlement agreement as amended, with grizzly being constructed for Santa Clara with later reversion to PG&E, principally because of continued high margin power sales to Santa Clara, avoidance of any necessity to refund construction funds, and PG&E ownership of grizzly." (D.92-09-022, Finding of Fact 8.)

PG&E believes that this revised language makes it even more clear that it was the Commission's intention that the engineering study costs of the settlement, the $1.9 million in dispute in this case, are reasonable costs to be borne by ratepayers.

We concur with PG&E that the September Mokelumne settlement decision clearly indicates that the ratepayers have benefited from the settlement agreement. It follows that the settlement costs should be borne by the ratepayers.

### 11.4 Common Plant Allocation

In addition to differences over the amount of common plant itself, there is a difference over the factor used to allocate common plant to the electric and gas departments. This difference in allocation factors will be addressed later in this decision.

PG&E has included $2,471,904,000 in its estimate of test year weighted average common plant. DRA's estimate is $2,433,487,000. The difference of $38,417,000 is due to the disputes listed in the table below.

| | PG&E | DRA | PG&E Exceeds DRA |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| 1. Electric Vehicles | 479 | 17 | 462 |
| 2. Child Care Center | 2,083 | 0 | 2,083 |
| 3. Steam System Sale Adjustment | -205 | 0 | -205 |
| 4. Recorded Capitalized PIP | 0 | -21,686 | -21,686 |
| 5. Prospective Capitalized PIP | 0 | -14,391 | -14,391 |
| Total Common Plant Difference | 2,357 | -36,060 | 38,417 |

#### 11.4.1 Clean Air Vehicles

PG&E exceeds DRA's estimate by $462,000. However, we will address the issue of electric vehicles conversions and purchases in the context of the overall subject of clean air vehicles. The subject is addressed including this particular item in Section 19 of this decision.

11.4.2 Child Care Center

The subject of PG&E's child care center has already received a fair amount of attention in this decision. In this context PG&E is seeking to include in its common plant estimate the cost of the establishment of the child care center in its general office building in downtown San Francisco. The costs include the architectural changes made to the building as well as the furniture and equipment within the center. The dollars involved are $2,083,000. DRA, consistent with its other recommendations, on this issue has not included any dollars in its estimate for this project for inclusion in plant. We will not repeat the arguments made by the parties on this issue. The rationale that we have already adopted is the same for these capital costs which PG&E seeks to include in rate base. We will deny inclusion of the child care center in PG&E's rate base for the reasons already stated in prior Section 9.3.3 of this decision. We note that the price tag on preparation of this child care center suggests that PG&E spared no expense in setting the center up. We will allow the shareholders to reap all the rewards of the goodwill that its center will engender both among its employees and within the community at large. DRA's recommendation on this issue is adopted.

11.4.3 Steam System Sale Adjustment

The dispute between the parties on this issue is one over timing, not substance. PG&E is in the process of selling its steam heat system. PG&E acknowledges that such a sale requires Commission approval under Public Utilities (PU) Code § 851 and plans to file an application soon seeking such approval. For purposes of this GRC, PG&E has assumed that the steam system sale will occur by January 1, 1993, the effective date of the decision in this GRC. Thus, PG&E has reduced common plant by $205,000 to reflect the amount of common plant (chiefly motor vehicles) that will be sold with the steam system. DRA, on the other hand, has made no reduction to common plant for the sale, because of the uncertainty of the timing of the sale. In its brief we note that PG&E continues to believe that the sale will occur before January 1, 1993 and therefore requests that the Commission adjust common plant to reflect the sale. This sale also has effect on the calculation of the four factor allocation as will be discussed in a subsequent section. As instructed by the ALJ, PG&E included a status report on the proposed sales in its comments on the proposed decision. PG&E now expects to file an application to sell its Steam System in December 1992. Clearly, approval of the application will not occur by January 1, 1993.

PG&E now concedes that it is not appropriate to reflect the pending sale of the Steam Heating System in electric and gas revenue requirements in Test Year 1993. Therefore, we will adopt the reductions proposed by PG&E to the 1993 electric and gas revenue requirements: $833,000 for electric and $174,000 for gas.

Finally, PG&E recommends that its 1994 attrition advice filing include a statement regarding the status of the sale of the Steam System. PG&E believes that if the sale is complete or reasonably expected to be complete by January 1, 1994, then the Commission should remove the 1993 revenue adjustments. We agree and instruct PG&E to present a status report on this issue in its 1994 attrition filing.

### 11.4.4 Capitalized Portion of the Performance Incentive Program (PIP)

Readers who enjoy beating dead horses will find this section of particular interest. We have already discussed the PIP extensively in this decision. (See Section 9.2.2.) Nevertheless, we will discuss in this section briefly the issue of the capitalized portion of PIP. PG&E correctly points out that DRA's recommended disallowance for the capitalized portion of the PIP is one of the largest in this GRC. The disallowance, as near as can be determined given the record, now totals some $50 million of plant in end-of-year terms. PG&E contends that DRA has taken a very cavalier approach on this proposed disallowance. PG&E points out that the proposed plant disallowance was not included in its original reports, either in the rate base witness' report or the PIP witness' report. The rate base witness acknowledged that his proposal was completely dependent on that of the PIP witness, Mr. Tolbert. During the opening hearings, the rate base witness testified that the proposed disallowance had increased from $13 million to $46 million. During rebuttal hearings, at the direction of the assigned ALJ, DRA attempted to clarify its position on this point. Unfortunately, the clarification attempt merely muddied the waters more. The only basis given for this recommendation was that total incentive costs were never approved by the Commission for placement in rate base. (Exhibit 164, p. 2 as corrected during hearings.)

PG&E points out that DRA's recommendation is both retroactive and prospective in nature. The Comparison Exhibit sets forth DRA's recommendation as a retroactive disallowance for PIP costs of $21,686,000 and a prospective disallowance of $20,026,000. ($14,391,000 on a weighted average basis.) The Comparison Exhibit notes that the information testified to by Mr. Tolbert during rebuttal hearings is not incorporated in the exhibit. The actual disallowance recommended by DRA is slightly higher than that set forth in the Comparison Exhibit. PG&E disputes DRA's argument that the Commission has never ruled that PIP amounts could not be placed in rate base. Rather, in the 1990 GRC decision, PG&E points out that the Commission recognized that it was extending to PG&E considerable flexibility in administering the total labor expense. This flexibility allows PG&E to put a portion of the expenses designated per salaries at risk, and to make such payments as bonuses or awards.

As we have already found in this decision, since PIP is part of PG&E's overall total cash compensation program, like other wage expenses it is appropriate for inclusion in rate base. PG&E

is correct that PIP is a labor-related overhead, no different than other labor-related overhead and supervisory costs. Because the PIP is a labor-related overhead, PG&E's standard practices, as well as the FERC accounting practices, require that a portion of the PIP costs be allocated to capital, to "follow" the capital labor dollars. PG&E points out that its practice of allocating PIP to capital is fully in compliance with the FERC Uniform System of Accounts, which has been adopted by the Commission. PG&E contends that failure to allocate a portion of this labor-related costs to capital would violate FERC principles. (Exhibit 224.)

Once again we must agree with PG&E on this issue as it relates to PIP. We reject DRA's proposal to retroactively and prospectively disallow nearly $50 million of common plant for PIP. DRA's recommendation is flawed in calculation, inconsistent with the results of our CACD workshop report on incentive pay, in conflict with DRA's position on total cash compensation, and in disregard of basic accounting principles governing allocations of overheads to labor. Therefore we approve all of PG&E's PIP dollars it has attributed to rate base. The only exception to this would be to future PIP dollars which PG&E has capitalized if they relate to employee positions that have been disallowed in this proceeding.

<u>11.4.5 Four-Factor Adjustment for Steam System Sale</u>

As we have already briefly mentioned, the expected sale of the steam system affects the estimate of common plant. It also has a linked impact on the calculation of the four factor allocation. Upon sale of the system, the 0.11% of total common plant that is currently allocated to the Steam Department through the four factor formula will be reallocated to the Electric Department at 0.08% and to the Gas Department at 0.03%. In other words, PG&E points out that the four factor allocation will change. Once again we point out that PG&E and DRA do not disagree on the method for calculating this change or the amounts; the only difference is due to the uncertainty of the sale itself. PG&E

posits that the Commission, if it approves the sale, should incorporate PG&E's position into this decision. The differences that result in the allocation of common plant due to the sale of the steam system are shown in the table below.

| | PG&E Exceeds DRA ($000s) |
|---|---|
| Total Weighted Average Common Plant Difference | 38,417 |
| Common Allocation to Electric (67.45%) | 25,912 |
| Four Factor Adjustment for Steam System Sale (.08%) | 1,978 |
| Electric Department Allocation | 27,890 |
| Common Allocation to Gas (32.44%) | 12,462 |
| Four Factor Adjustment for Steam System Sale (.03%) | 742 |
| Gas Department Allocation | 13,204 |

As we just discussed in Section 11.4.3, we are assuming for purposes of Test Year 1993 that the sale of the Steam System did not occur and have adjusted figures in our appendices accordingly.

### 11.4.6 Seismic Retrofitting for 215/245 Market Street Properties

PG&E is currently pursuing a seismic retrofit of its 215 and 245 Market Street building, which are part of the company's San Francisco general office complex. This retrofit work began with the December 1991 relocation of employees who work in the buildings and it is expected to be completed in 1996.

PG&E conceded to DRA's auditors' recommendation that these buildings should be temporarily removed from rate base pending completion of the seismic retrofit. Ms. Thompson, for DRA, further recommended that the plant be temporarily placed in CWIP, where it will accrue AFUDC. (Exhibit 105.)

At hearings, PG&E sought a clarification of DRA's proposal. PG&E requested that property taxes should also be capitalized as well as AFUDC while the plant is not in rate base. Further, under DRA's proposal, which PG&E concurs with, once the retrofit of the buildings is accomplished the buildings will once more be considered used and useful. And at that time the net plant would be transferred back to rate base and depreciation of the amount, plus the accrued AFUDC and property taxes, would recommence.

We agree with DRA, and are happy to see PG&E's concurrence, that these buildings should be removed from rate base during their retrofit. Therefore we will adopt DRA's position on this issue with PG&E's clarification discussed above.

We note that by treating these buildings in this manner, we are not at this time passing judgment on the reasonableness of the dollars spent for the seismic retrofit of these buildings. We note this is an area where there can be a great variation in cost of the work, and we expect PG&E to use its dollars wisely if it hopes to obtain ratepayer funding for these projects. We trust PG&E will not use seismic retrofitting as an excuse for unnecessary "goldplating" of its buildings. We look forward to exploring this issue in PG&E's next GRC.

<u>11.4.7 MCI Agreement Telecommunications Savings</u>

In D.92-07-007, the Commission approved PG&E's A.92-04-011, finding in Conclusion of Law 20 that the MCI "agreement offers substantial benefits for ratepayers." That decision found that MCI will provide PG&E a certain amount of capacity on its nationwide telecommunication system in exchange for use of two parts of PG&E's system.

D.92-07-007 went on to order PG&E to:

> "present in the update portion of A.91-11-036 its revised estimate of the annual telecommunications expenditures for the years 1993 through 1995. The revised estimates shall

> incorporate the savings resulting from the agreement."

Therefore, during the Update hearings PG&E presented additional information as to where the promised savings for ratepayers due to the MCI agreement were to be found in this GRC. Unfortunately, there seem to be a substantial difference in dollar savings between what was represented in the MCI agreement application and this GRC update. The ALJ assigned to the PG&E/MCI application attended the Update hearings on this issue. Seemingly, what had been promised as ratepayer savings in the PG&E/MCI application were more appropriately called cost avoidances in the GRC. Apparently, PG&E chose to increase its capital expenditures in other telecommunication projects to make up for the so-called savings from the MCI agreement. DRA signed off on these increases, or shifting of dollars to other fiber optic network or other ongoing projects. PG&E reduced its request for A&G expenses in Account 921 by $567,000 on a total company basis. (Exhibit 237, p. 2D-3 through 2D-5.)

However, this data still seems to be in conflict with had been represented in the prior application. Therefore, the assigned ALJ ordered PG&E to prepare further exhibits to explain the discrepancies between the two showings. The ALJ received as Exhibit 245 portions of the materials submitted with A.92-04-011 filed under seal in both proceedings. Likewise Exhibit 246, an effort by PG&E to reconcile the material presented in this GRC with the PG&E/MCI application, was filed under seal. Cross-examination by the PG&E/MCI ALJ was held during the rate design phase of this proceeding.

We are resigned to the fact that seemingly the savings promised in the PGE/MCI application are in fact mere cost avoidances. Likewise, these dollars have been placed into other telecommunication capital projects, resulting in a much smaller net reduction in ratepayer expenses than we have previously hoped.

While we will make no adjustments based on the record before us, we must caution PG&E that in the future it must make a greater effort to correctly and clearly represent the true facts in any applications for approving contracts with other parties. In hindsight, we do not know whether or not we would have approved the MCI/PG&E deal given the record that is now before us. However, we have done so and we will stand by our approval. PG&E is warned that in the future when it represents savings to the Commission for the ratepayers that they had best be clear on exactly what kind of savings those will be.

11.4.8 Materials & Supplies

PG&E estimates $93,429,000 in inventory for electric M&S. DRA's estimate is $87,169,000. The difference of some $6.2 million is rooted in DRA's estimating methodology. Once again, we note that this is a subject that DRA chose not to address in its opening brief. However, in the Comparison Exhibit the difference between the parties is shown on page 3-97. (Exhibit 235.) PG&E bases its estimate on its own M&S inventories. DRA's recommendation is based on a belief that PG&E's M&S ratios, of M&S to plant and M&S to nonlabor expenses, are higher than those for other major energy utilities in California. DRA used San Diego Gas & Electric Company's (SDG&E) ratio of M&S to average plant (the next highest ratio) as a comparison. Based on that comparison, DRA recommends an overall 6.7% reduction of PG&E's M&S.

PG&E, on the other hand, does not believe it is valid to compare the levels of inventory at various utilities using the ratios employed by DRA as a means to determine the level of M&S that should be allowed in rate base for any given utility. (RT 55:5085.) PG&E points our that the operating characteristics of utilities, which have a direct impact on the amount of M&S which should be held in inventory, can vary significantly. PG&E believes that M&S turnover is a better indicator of the effectiveness of M&S handling policies and procedures than the plant to M&S ratios used by DRA. PG&E argues that a high M&S turnover indicates that materials are moved quickly and efficiently in and out of the warehouse, reducing the need for high inventory levels. PG&E points to a 1990 inventory survey conducted by Florida Power & Light which found PG&E to have the highest materials turnover of the utilities surveyed. (Exhibit 224, p. 3.)

Additionally, PG&E believes that DRA has incorrectly calculated its results. DRA relied on FERC Form 1 Annual Reports for its data. PG&E points out that the total materials reported in the FERC Form 1 are almost three times as great as the amount of M&S included in PG&E's rate base. This is because materials from FERC's perspective include Diablo Canyon M&S, fuel stock, stores, gas linepack, unpaid liabilities, stock which is inactive after three years, and other minor categories of materials. None of these are included in PG&E's rate base recommendation. PG&E concludes that when these adjustments are made to the FERC Form 1 data, PG&E's M&S ratios are not out of line with other California utilities. Finally, PG&E points out that its estimate is a conservative one, simply escalating the recorded end of year 1990 M&S balance. This approach deliberately makes no allowance for real growth in PG&E's system, reflects the successful efforts of PG&E's warehouse management personnel to implement innovative inventory control procedures, thereby lowering inventory levels and holding the line on cost increases. All this is done while still maintaining quality service to customers, in PG&E's view. (RT 22:1839 through 1841.)

In reviewing the record on this issue, we find PG&E's showing to be adequate and more persuasive than DRA's arguments. Therefore, we will adopt PG&E's M&S estimate for rate base purposes.

11.5 Depreciation Reserve

Plant in service differences are the only reason that PG&E and DRA proposed different depreciation reserve amounts. The differences are due to (1) PG&E and DRA disagree on plant additions up to and including Test Year 1993 and (2) PG&E recommends retaining Geysers Unit 15 in rate base while DRA recommends its removal. The Geysers Unit 15 will be discussed in a later portion of this decision. As to the other, we will adopt depreciation reserve amounts consistent with the plant additions we have approved in this decision.

11.6 Customer Advances

PG&E has stipulated to DRA's estimate of customer advances, which has increased rate base. DRA believes that its method, which used more recorded years of data, provides a more accurate allocation of advances between electric and gas customers. Even though there is no dollar difference between PG&E and DRA on this issue, PG&E agrees with DRA's proposal that PG&E investigate alternative methods for forecasting customer advances prior to PG&E's next GRC. Therefore, we shall endorse the stipulated agreement set forth in this GRC and order that PG&E report to us in its next GRC the results of this investigation.

11.7 Utility Design, Inc. Recommendations

A small consulting engineering firm, Utility Design, Inc. (UDI), has made some recommendations in this case regarding tariff provisions and affecting rate base estimates. The underlying premise of this recommendation is that if applicant-installed facilities (AIFs) were used more by the utilities, then there would be a tremendous saving to the ratepayers. It is no mere coincidence that this position would also further the business opportunities of UDI. UDI argues that PG&E's 1993 Test Year rate increase could be reduced by almost a hundred million dollars if we applied tariff rules currently in effect and required and encouraged more AIFs. (Exhibit 303.)

However, UDI completely failed to prove its hypothesis. UDI's cross-examination of PG&E's plant witness indicated how drastically it misused PG&E's recorded plant amounts to reach its conclusion that there will be "savings" from increased use of AIFs. We find the arguments raised by UDI in this proceeding to be without merit.

On a procedural note, PG&E points out that the same arguments have been raised by UDI before. In PG&E's last GRC, these issues were raised and the ALJ ruled that they should be more properly addressed in a complaint case. PG&E points out that complaint cases still open. Further, the Commission has opened Rulemaking (R.) 92-03-050 to investigate other aspects of the line extension rules for gas and electric facilities, which are the tariffs of concern to UDI.

With a great deal of tolerance, the assigned ALJ in this GRC allowed UDI to present its desired showing. However, we stand by our finding that this issue is better heard in a complaint case. We realize that the complaint is still pending before us. Therefore, we will direct this issue, if UDI wishes to pursue it, to the rulemaking we have recently opened. We feel compelled to caution UDI that the showing it has made in this proceeding, if any example of the kind of showing it is capable of making, is not persuasive and will not at the end of the day compel us to adopt its views.

## 12. Depreciation

PG&E's electric depreciation expense is $4,372,000 less than DRA's estimate. This is out of the total of some $620,000,000. The difference is due primarily to DRA's proposal to provide additional depreciation for retired Unit 15 at the Geysers. The remaining differences are due to DRA's proposed changes to recorded and forecast depreciable plant. Other than these differences, PG&E and DRA are in agreement with characteristics of depreciation, expected service lives, net salvage rates, and depreciation curve types. PG&E's estimate of $6,503,913,000 for the weighted average electric depreciation reserve is less than DRA's estimate of $6,537,986,000 by some $34 million. This difference is once again due to DRA's proposal regarding the treatment of Geysers Unit 15. (Geysers Unit 15 will be addressed as a separate section in this decision.) The remaining difference is due to DRA's proposed changes to recorded and forecast plant amounts.

## 13. Decommissioning

### 13.1. Fossil Plant Decommissioning

Decommissioning costs include the costs associated with the demolition of each powerplant and the restoration and remediation of the plant sites. These costs are associated with providing service. DRA does not object to the fossil decommissioning costs, or the assumptions used in developing these costs. (Exhibit 108.)

The decommissioning cost estimates include preparing the plant for demolition which includes the removal and disposal of nonhazardous, hazardous, and asbestos-containing materials. Secondly, the demolishing, removing, transporting, and disposing of the powerplant and its associated equipment is completed. And finally, the sites are restored following the demolition, removal, and disposal activities. (Exhibit 6, Chapter 13.) Currently, total financial costs are $751 million. These cost estimates are based on current technology and current local, state, and federal regulations. These estimates will be reviewed and revised in each subsequent GRC filing to account for future increases or decreases resulting from changes in project scope, cost estimating, methodology, technology, and regulations. It maybe 20 years or more before some of these plants are actually decommissioned, therefore, a reasonable expectation is that these cost estimates will change. However, the current estimates are the best estimates available at this time. Therefore absent any future changes, these are the costs that PG&E reasonably can expect to incur for decommissioning. We agree with PG&E that these estimates should be included in rates as reasonable estimates of costs required to provide service in a manner consistent with protection and enhancement of the environment of California. We concur with the recommendations of DRA that such costs should be internalized within rates.

13.2 Nuclear Decommissioning

PG&E and DRA agree on the amount of nuclear decommissioning expense for ratemaking purposes of $54,474,000 annually. (Comparison Exhibit, Exhibit 235, p. 3-92.) PG&E's nuclear decommissioning cost study was admitted by stipulation. We agree with PG&E that its cost study was consistent with the requirements of the Nuclear Facility Decommissioning Act (Act), PU Code §§ 8321 et seq. The purpose of the study is to assure that contributions accumulate sufficient funds for decomissioning. Such costs and resulting contributions are reviewed during each rate proceeding.

Cost estimates for decommissioning are based on loan changes from prior studies, state-of-the-art technology, and current federal regulations, pursuant to § 8327 of the Act. These studies produce estimates resulting in total decommissioning costs on a 1991 dollar basis of $712,806,000, including contingency, for Diablo Canyon and $79,214,000, including contingency, for Humboldt Bay Unit 3. (Exhibit 6, Chapter 13-C.) Based on these cost estimates, PG&E estimated the revenue requirements for decommissioning based on cost escalation and return assumptions. The purpose of these estimates was to review the adequacy of the contributions to the decommissioning funds for both Diablo Canyon and Humboldt Bay Unit 3. PG&E is required to maintain externally managed, segregated funds for decommissioning. To estimate the required contributions to reach the ultimate cost of decommissioning, escalation rates are used to convert the estimated decommissioning costs in 1991 dollars into future year dollars. This total is compared with contributions, and the estimated rates of return, net of any taxes or costs to administer the funds, on the invested decommissioning trust funds. (Exhibit 6, p. 13B-4.)

PG&E points out that for Diablo Canyon Unit 1 contributions could be slightly higher and Unit 2 contributions could be slightly lower. However, in order to avoid unnecessary administrative burden of revising IRS Qualified Contributions, PG&E recommends that this minor fluctuation in estimated contributions not result in a change for this rate case cycle in the present level of ratemaking expense for nuclear decommissioning for Diablo Canyon.

For the Humboldt Bay plant, the data presented in this GRC indicates that there now exist adequate funds to complete the decommissioning of Humboldt Bay Unit 3. Consistent with § 8322 of the Act, PG&E proposes that neither additional contributions nor refunds are necessary at this time for Humboldt.

Consistent with the requirements of the Nuclear Facility Decommissioning Act, we find PG&E's nuclear decommissioning cost estimates to be reasonable and authorized their inclusion in rates for this rate case cycle 1993 to 1995, subject to review and updating in PG&E's next GRC.

## 14. Working Cash

For the most part, PG&E and DRA have resolved prior and during hearings the majority of their differences regarding the working cash line item in the results of operations. As shown in the Comparison Exhibit (Exhibit 235), one final difference between PG&E and DRA is the allocation of certain total company items to the Electric Department based on a four factor allocation. PG&E uses 67.53% while DRA uses 67.45%, a 0.08% difference. In addition, PG&E and DRA differ on the Electric Department rate base, working cash, by an amount of some $16 million. This difference derives mainly from differences in inputs, from other sources in the results of operations, and from different escalation rates.

PG&E and DRA are basically using the same base forecast amounts for all components of the operational cash requirements before escalation, except for the amounts of accounts receivable and deferred debits, where PG&E stipulated to DRA's accounts. While PG&E and DRA are in agreement on the methodology, different escalation and growth factors were used by DRA in developing the operation cash requirements. We will use escalation rates for working cash that are consistent with escalation rates adopted elsewhere in this decision.

Other differences that are the result of difference expense estimates provided by other witnesses will be resolved by being consistent with the estimates adopted for particular accounts.

## 15. Jurisdictional Allocation

DRA and PG&E agree on the methodology or allocation of costs and revenues between state and federal jurisdictions. Given that no other party contested the jurisdictional allocation, PG&E's method for jurisdictional allocation and its underlying assumptions should be adopted.

In PG&E's last GRC, we ordered that in future general rate cases PG&E provide a cost-benefit study for its discounted sales to be included in CPUC jurisdiction during the test year. (34 CPUC2d 199, 275.) PG&E proposes to continue the treatment approved in that GRC of allowing revenues and costs associated with discounted sales to remain in the CPUC jurisdiction. While below fully allocated costs, the rates for discounted sales are above the incremental cost of providing service. Therefore this provides the contribution to margin to benefit all customers. PG&E presented in this proceeding cost-benefit analysis demonstrating the benefits of each of these contracts. (Exhibit 8.) No party contested this proposal. We find PG&E's proposal reasonable and shall adopt it in this proceeding.

## 16. Results of Operations for Gas Department

### 16.1 Overview

If the reader of this decision is daunted by yet another foray into more seemingly endless accounts, he should take comfort from the fact that there are first, fewer accounts in dispute for the Gas Department, and second, many of the arguments are common to those already discussed in detail in the Electric Department. Therefore, we endeavor not to repeat arguments in this section.

Both PG&E and DRA chose a base estimate to estimate the expenses associated with gas production, storage, transmission, and distribution for the test year. The base estimate was derived either from the use of 1990 recorded data or an average of the costs in previous years. Adjustments were then made to some of the accounts to reflect specific changes and activity levels, special projects, and additions or deletions to plant.

### 16.2 Gas Production Expenses

#### 16.2.1 CPUC Account 807.2 (PG&E Account 1716): Purchased Gas Measuring Expenses

This account includes the expenses incurred directly for measurement activities associated with purchased gas for resale. PG&E originally used a five-year average for both materials and labor base estimates. DRA chose to use 1990 recorded costs. In the Comparison Exhibit, PG&E accepted DRA's position. (Exhibit 235.)

#### 16.2.2 CPUC Account 807.4 (PG&E Account 1717): Purchased Gas Calculations Expenses

PG&E is requesting $1,584,000 for this account, with DRA's estimate at $1,533,000. The $212,000 difference represents a reduction DRA made to PG&E's request for additional manpower due to gas industry restructuring and associated PIP. PG&E accepts reductions proposed by DRA for forecast changes for labor and materials and services in Account 1717 of $72,000 and $21,000, respectively. Thus, PG&E has conceded that the use of last recorded year data as a base is reasonable.

The issue still in contention between the parties is whether new positions need to be filled for this account (and related accounts to be discussed later) in light of the restructuring that has been going on in the gas industry. PG&E argues that additional positions are necessary because the gas production operation has been extensively affected by gas industry restructuring since May 1, 1988. Five additional positions were added in 1990 to deal with these changes. DRA points out that three of the five additional positions have yet to be filled by PG&E. PG&E also justifies its request for additional positions based on the amount of overtime that its existing employees have put in in recent years. DRA counters that argument by stating that overtime pay is captured in recorded year data and thus is already accounted for. While DRA agreed that the large amount of overtime was unreasonable to expect of anyone, PG&E continues to maintain that the current unfilled position should take care of the increased need. The request for PG&E staffing is merely to carry out industry structure changes to provide new customer options at the direction of the Commission and therefore should be accepted.

While in other sections of this decision we have pointed to the compensation strategy of PG&E as sufficient reason to avoid needing new positions, (i.e., improved productivity from its employees) in this instance we agree with PG&E that the gas restructuring program which we have embarked upon could and has increased the workload on PG&E's Gas Department. The documented overtime hours indicate a need for additional personnel. There is nothing in our ongoing gas restructuring dockets to indicate that this workload will diminish at any time in the near future. We note that PG&E has in fact shown a reason why it needs the increased positions while DRA's argument that the three positions unfilled in 1991 should take care of the increased demand is not documented. We will adopt PG&E's estimate for CPUC Account 807.4.

16.2.3 CPUC Account 807.5 (PG&E Account 1718): Other Purchased Gas Expenses

This account includes the expenses associated with purchased gas for resale that are not incorporated elsewhere. Originally PG&E used a five-year average to derive both its base estimate for labor and materials and services. DRA used 1990 recorded data for both categories. In the Comparison Exhibit PG&E has accepted DRA's position on this account. Therefore, DRA's position, being the more reasonable one in any event, will be adopted for this account.

16.3 Gas Storage Expenses

16.3.1 CPUC Account 831 (PG&E Account 1411): Maintenance of Structures and Improvements

This account includes the expenses associated with the maintenance of underground storage structures. PG&E used 1990 recorded data to arrive at a base estimate of labor and materials expenses it claims to need to continue levee repair at McDonald Island. The total dollars for the McDonald Island levee repair that are in dispute between PG&E and DRA are $2.5 million. PG&E also seeks $383,000 for cleaning and repainting the compressor and processing platforms beginning in 1992 and continuing through 1994. DRA recommends that this $383,000 adjustment for repainting in the 1995 attrition year should be disallowed.

The disagreement over the McDonald Island levee repairs cannot be addressed without some historical background being presented. The failure of the levees around McDonald Island in 1982 led to the formation of a Reclamation District to undertake repairs to the levee system. Five property owners and PG&E make up the Reclamation District and PG&E currently holds one of the three seats on the Reclamation District's board of directors. (RT 17:1177-1178.)

The issue of the McDonald Island levee repair work was the subject of testimony in PG&E's last general rate case. There, PG&E's witness testified that the work was expected to be completed by 1991. Additionally, in that GRC, the total levee rehabilitation program cost was estimated at $13,717,000. (RT 16:1154-1155.) Likewise in the last GRC, PG&E's share of the assessments to the Reclamation District was 79%; in the 1990-91 fiscal year that share was increased to 95%. None of the other property owners on McDonald Island have, at any time since the project began, contributed any cash to the assessment district. Instead, all the other players have made their payments in "dirt." (RT 16:1178.)

DRA states that these facts make it unreasonable for the ratepayers to spend any more money on the McDonald Island levee repair work. DRA bases this recommendation in large part on its opinion that PG&E seems to have little knowledge of, or control over, what is being done with the money. DRA points out that the design of the levee repair work seems to be a moving target fluctuating between a 300-year flood design down to a preparation for a 50-year flood. (Exhibits 160, 161.)

As best as DRA could ascertain, the reason for the delay in completing the levee repairs is the virtual disappearance of the soil used to rebuild the levees. This is due in part to subsidence and in part to the nature of the soil being used. Twice as much soil will have to be shifted as originally predicted. DRA is concerned about the competence of the consultants, engineers, and contractors who have so miscalculated the cost of levee repair. DRA further believes that the other property owners of the Reclamation District, who are only paying in dirt, should somehow have to increase their shares since the subsidence of the dirt has been one of the problems with the project.

Furthermore, DRA is troubled that PG&E has not aggressively sought reimbursement of some of these funds from the State of California. DRA concedes that it is the Reclamation District that must seek these funds but notes that PG&E is one of the votes on the Reclamation District and is certainly the major, in fact the only, financial contributor to the project. DRA requests disallowance of this item, not because it does not believe that McDonald Island is of use to ratepayers, but because DRA is very concerned about the casual way in which PG&E has thus far handled this expenditure of ratepayer funds.

PG&E counters with statements regarding the value to ratepayers of protecting the facilities on McDonald Island. PG&E points out that its gas storage facilities on McDonald Island have a cycle capability of 27 billion cubic feet and a maximum daily withdrawal capability of approximately 1.5 billion cubic feet. PG&E also cites the testimony of intervenor Sesto Lucchi, who testified that gas storage facilities are a small cost item compared to the benefits provided by storage to northern California ratepayers. (Exhibit 302.) PG&E argues that its share of the special assessment fee to the McDonald Island Reclamation District for completion of levee rehabilitation work in 1993 is a reasonable expense and should be paid for by PG&E's ratepayers. PG&E argues that the costs for such a project are likely to change over time. PG&E's current best estimate for the total project is approximately $15.5 million. (RT 16:1159.) PG&E maintains that the range has gone as high as $28 million. In addition, an engineering study done by PG&E concluded the costs to be between $11.8 million and $17.5 million. (Exhibit 35, p. 2.)

PG&E contends that it is unclear whether there will be funds available through the state for the Reclamation District to claim. Finally, PG&E argues that its responsibility to provide gas during the winter heating season means PG&E must take reasonable action, including ongoing levee rehabilitation. PG&E believes that the cost of failing to maintain the levees at McDonald Island would be far more expensive than including payments reasonably expected to occur for 1993 levee work in gas storage expenses. PG&E has not so far experienced the same level of curtailments as other California gas suppliers. Therefore PG&E concludes that inclusion of these levee repair fees to the McDonald Island Reclamation District is appropriate and provides direct benefit to ratepayers.

On this issue we must agree with DRA that PG&E has failed to adequately substantiate and justify why the ratepayers should continue to fund the project that should have been already completed. PG&E's initial showing on this issue was not terribly specific, and it is unclear as to what efforts PG&E is making to influence the Reclamation District in the running of its project in the best interest of its ratepayers. We acknowledge that programs often have cost overruns. However, when this occurs, the burden is on the utility to convince us why we should continue to authorize funds provided by ratepayers. We are unconvinced that PG&E's share of the total project is reasonable and in the ratepayers' interest. We note that the ratepayers have already funded some $13 million towards the levee repair work. We suspect that PG&E will have a greater incentive to urge the Reclamation District to obtain state funds if in fact PG&E shareholders are at risk for these dollars. While we agree that the McDonald Island storage facility is a benefit to ratepayers, PG&E has failed in its showing to convince us that more money is justifiably authorized for this project. Therefore, we will adopt DRA's estimates for CPUC Account 831.

**16.3.2 CPUC Account 834 (PG&E Account 1414): Maintenance of Compressor Station Equipment**

This account includes the expenses associated with the maintenance of underground storage compressor station equipment. Although the parties originally disagreed as to the estimating methodology, PG&E accepted DRA's position in the Comparison

Exhibit. (Exhibit 235.) Therefore, we will adopt DRA's estimate for this account as reasonable.

### 16.4 Gas Transmission Expenses

#### 16.4.1 CPUC Account 851 (PG&E Account 1851): System Control and Load Dispatching

Out of an account of over $6 million, PG&E and DRA disagree over roughly $160,000. However, PG&E accepted reductions of $30,000 proposed by DRA for mathematical error in this account. (PG&E Opening Brief, p. 263.) The arguments related to this account are basically the same as those discussed above for CPUC Account 807.4. The issue is the need for additional manpower to do gas industry restructuring. DRA for this account recommends disallowance of funding for three of the eight positions sought. The three positions DRA believes are unnecessary are for a gas planning engineer, gas analyst, and gas analyst programmer. While DRA agrees that additional work may result from gas industry restructuring, DRA does not believe the need for new employees will be as great as PG&E claims.

We believe that PG&E has sufficiently shown that the gas industry restructuring has caused a significant increase in workload for the departments affected by this account. We have no wish to foster a system of excessive overtime for existing workers. In fact we disagree with DRA's statement in its opening brief that no negative effects have been found on the remaining staff given positions not being completely filled. (DRA Opening Brief, p. 26G.) DRA does not give any particular justification for its recommendation of fewer staff positions. We are well aware given the number of decisions and proceedings ongoing in this area that the workload must have increased for PG&E staff. Therefore, we will authorize what PG&E has requested for CPUC Account 851.

## 16.5 Gas Distribution Expenses

### 16.5.1 CPUC Account 877 (PG&E Account 1957): Removing and Resetting Meters and Regulators

This account includes the expenses associated with resetting, removing, or changing nonindustrial meters and regulators. Both PG&E and DRA used 1990 recorded data to derive their base estimates of labor and materials expenses. The differences in this account are due to differences regarding two programs of PG&E. The first is the gas pipeline replacement program (GPRP) and the second is the meter protection program (MPP). The adjustment for the GPRP in this account which DRA seeks is $243,000 and the adjustment for MPP in this account is $1,623,000. We will address these programs in the sections below. These programs also relate to several accounts to follow. We believe it makes more sense to discuss the programs as a whole.

#### 16.5.1.1 Gas Pipeline Replacement Program (GPRP)

The GPRP was established in 1984 to replace, according to a 20-year schedule, deteriorating gas piping systems, specifically all cast iron distribution mains and most pre-1931 steel distribution mains. At the same time service replacement and meter relocation work is being done. The GPRP involves significant O&M dollars in several different accounts due to the required relocation of existing facilities in conjunction with the capital reconstruction work. Included in the operation expenses are the costs of maintaining service to customers during construction, coordinating the work with the various agencies and utilities in the area, and engineering. Maintenance expenses include the cost of relocating gas meters, of bringing the existing services and meters up to current codes and standards not in effect when the original construction took place.

DRA has recommended a reduction in Test Year 1993 expenditures for this program in several accounts:

PG&E Account 1957 - $243,000
Account 1964 - $1,132,000
Account 1603 - $525,000
Account 1607 - $809,000
Account 1609 - $245,000

The primary reason for DRA's suggested reductions from PG&E's requests for this program is a comparison of what PG&E has actually spent on GPRP as opposed to what it has forecasted since 1988. DRA is convinced that PG&E consistently overstated the amounts needed to perform the different categories of work. DRA reached this conclusion through studying PG&E's GPRP annual progress reports filed with this Commission and developed from them unit costs for the services to be replaced. DRA believes that there is a declining trend in expenses in the San Francisco area where the major portion of the work will take place. DRA also has taken into account PG&E's six years of program experience. DRA argues that the one undeniable fact about the trend of GPRP expenses is that PG&E has consistently recovered more in rates than it has spent for O&M costs. Since none of the excess amounts have been applied towards the expenses in future years, DRA believes that these overestimations have resulted in windfall profits to PG&E shareholders and should be refunded. Finally, DRA recommends that further downward adjustment should be made to all the accounts including GPRP expenses in the attrition years if PG&E spends less than what is budgeted for GPRP in Test Year 1993. (Exhibit 104.)

PG&E counters these arguments with the fact that the GPRP is moving into neighborhoods in San Francisco where the density levels will result in higher costs.

PG&E also points out that DRA's analysis and development of unit costs ignored abnormal data such as the fact that the dollars from the Marina District reconstruction after the 1989 Loma Prieta earthquake were less than they would be in normal circumstances, since PG&E had the advantage of being able to work in an area where the streets were closed down anyway. Likewise, PG&E points to a fact that a second DRA witness testified that a higher allowance for expenditures in San Francisco is needed because of the density and resulting working conditions. PG&E points out that DRA gives no citation to any evidence for its proposition that PG&E has recovered more in expenses than it has spent on this program. In fact, PG&E replaced more gas pipelines than was expected in 1991.

PG&E points out it is reasonable to expect the expense level for installation to change as work is performed in different areas of the city. In 1992 and 1993, the work will be moving into Chinatown where costs are anticipated to be high because of the density of the area.

Finally, PG&E points out Safety Division of the Commission has supported PG&E's existing and planned gas pipeline replacement program. PG&E points out that the importance of this program should be obvious. It is part of the company's overall seismic safety improvement program, for which the Safety Division of the Commission recommends older facilities be replaced. (Exhibit 74.) Finally, PG&E argues that it would be inconsistent with the State of California's policy on seismic safety improvement by the year 2000 for this Commission to reduce the dollars which PG&E plans to spend on this program for Test Year 1993 and beyond.

On this program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. The 1989 Loma Prieta earthquake certainly showed us the importance of PG&E replacing its old pipes throughout the City of San Francisco. In fact, perhaps if the Marina District had its pipelines replaced, some of the problems that erupted in that neighborhood as a result of the earthquake may not have occurred. In any event, we want PG&E to move forward with this program with due diligence. Because of that desire, it would be unreasonable for us to authorize less money than PG&E believes it needs to keep this program on track. Likewise, we agree with PG&E's analysis that the cost of doing the pipeline replacement will vary from neighborhood to neighborhood in San Francisco. Certainly to anyone who has walked the streets of Chinatown and the Financial District will realize that the unit costs will be substantially higher, than for example, what the costs were on deserted streets in the Marina District after the earthquake. By authorizing the dollars PG&E requests for all of the accounts that deal with the gas pipeline replacement program, it is our fervent hope that PG&E actually spends the money on this program. We agree that this program is an important element of seismic safety improvement and urge PG&E to exercise due diligence in not only keeping the program on its targeted time line, but where feasible speeding up the program. Therefore, we will authorize all dollars related to the GPRP which PG&E has requested in this proceeding.

16.5.1.2 Meter Protection Program (MPP)

In 1990, PG&E began the meter protection program to correct gas meter locations not in conformance with current policies and standards. Thus far, 7,821 meters have been checked and corrective action has been taken on 3,673 meters. (Exhibit 7.) PG&E seeks an increase of some $3.6 million for Test Year 1993 for this program. DRA, on the other hand, recommends that the increase for 1993 over 1990 recorded expenses be limited to roughly $2 million. The difference of $1.6 million is in dispute between the parties. This dispute exists in CPUC Account 877, discussed above.

DRA proposes a disallowance for this project for the following reasons. First, DRA is not satisfied with PG&E's explanation of the dramatic discrepancies in the costs of installing barrier posts. According to information provided by PG&E, DRA notes that the installation of the barrier posts in Santa Rosa costs $91, while in San Francisco it costs $1,161. Even PG&E's own witness questioned the accuracy of these estimates, but

PG&E then proceeded to base its expense estimate on these numbers anyway.

Secondly, DRA believes that there is an obvious overlap between work performed in connection with the GPRP and that involved in the MPP, raised in the concern that ratepayers maybe paying twice for some jobs. Finally, DRA points out that PG&E's own annual progress reports on the MPP show that PG&E has overcollected for the work it has performed relocating, replacing, and protecting meters. (RT 17:1214.) DRA recommends that future expenditures for attrition years should be adjusted downwards if PG&E does not spend whatever the budgeted amount is. PG&E argues that the reduction in the expense estimate suggested by DRA could extend the MPP completion schedule beyond what has been agreed upon with the Commission's Safety Division. However, PG&E does not actually address DRA's assertion that there is overlap with the GPRP program, other than denying that ratepayers will pay twice for any part of the work. PG&E also states that DRA's concerns about unit costs are not well-founded. PG&E claims it used barrier post installation estimates of from $150.00 to $250.00 per post.

For this program, we do not believe PG&E has made strong enough showing to justify the increase it requests. We believe PG&E did a better job in justifying its gas pipeline replacement program dollars. We agree with DRA that there should be some cost savings that PG&E has not calculated in coordinating the MPP program with the pipeline replacement program. Likewise, we are disconcerted by the seemingly wide variance in costs related to barrier posts. We note that DRA's recommendation does in fact allow for an increase over 1990 recorded dollars. Therefore, we will authorize DRA's recommended dollar amount for CPUC Account 877 for the meter protection program. This results in a downward adjustment from PG&E's request of some $1.6 million.

### 16.5.2 CPUC Account 879 (PG&E Account 1964): Customer Installation Expenses

This account includes the expenses associated with work performed on customer premises other than removing and resetting meters and regulators. The disagreement in this account between PG&E and DRA relates to the estimated GPRP expenses. DRA recommended the disallowance of $1,132,000 for this account. For the reasons already discussed related to GPRP, we will approve PG&E's recommendation for Test Year 1993 expenses for CPUC Account 879.

### 16.5.3 CPUC Account 880 (PG&E Account 1960): Distribution Maps and Records

Due to a difference in their estimating methodologies, DRA recommends a $270,000 reduction in this account from PG&E's request. This account includes the expenses associated with the preparation of distribution maps and records. PG&E used a five-year average for both its labor and materials expenses to account for fluctuations that occur in this account. DRA believes the use of 1990 recorded data is more appropriate in order to reflect improvements in computer mapping technology that have occurred since the last GRC. However, PG&E counters that its automation program does not so much lower expense costs but rather provides the customer with better service. Future plans, for example, according to PG&E, include expansion to handle distribution data bases and document management associated with the map facilities. (Exhibit 7, Chapter 8.)

We agree with PG&E that given the fluctuations in this account, its estimate is reasonable. Likewise, we agree that in this instance the computerization has not necessarily resulted in the reduction of expenses.

16.5.4 CPUC Account 880 (PG&E Account 1961): Other Expenses

We note that PG&E has accepted DRA's position in the Comparison Exhibit; therefore, there is no longer any disagreement over this account. We will adopt the number as set forth in the Comparison Exhibit for this account. (Exhibit 235.)

16.5.5 CPUC Account 887 (PG&E Account 1603): Mains--Other

This account includes the expenses associated with the maintenance of distribution mains, excluding leak repairs on cast iron mains. DRA had recommended a disallowance of $525,000 due to the GPRP expenses. We reject DRA's position on GPRP and adopt PG&E's estimate for CPUC Account 887.

16.5.6 CPUC Account 892 (PG&E Account 1607): Services

This account includes the expenses associated with the maintenance of gas distribution services. Once again, the only disagreement relates to the gas pipeline replacement program. Once again, we reject DRA's recommended disallowance in this account of $809,000 for the reasons stated in the above section.

16.5.7 CPUC Account 893 (PG&E Account 1609): House Regulators

This account includes the expenses associated with the maintenance of gas regulators. Again, DRA's only disallowance relates to the GPRP, of $245,000. Maintaining consistency, we reject DRA's recommended disallowance for GPRP. We will adopt PG&E's estimate for CPUC Account 893.

16.6 Customer Account Expenses

PG&E's estimate of $87,949,000 for Gas Department customer account expenses (excluding uncollectible accounts) exceeds DRA's estimate of $85,822,000 by $2,127,000. Disagreements over estimates for customer growth in several accounts contribute to $1,184,000 of the difference. The difference of $943,000 in PG&E Account 976 is due to DRA's exclusion of the customer payment option communication program and the customer's service program evaluation project. (Exhibit 235, pp. 4-35, 4-36.)

We note that estimates of Electric and Gas Departments customer accounts expense are derived from an allocation of total expenses. This is done because the expenses are similar or identical for both departments since, for the most part, it is the same meter reader or the same clerk performing work for both departments. Therefore, issues which were discussed in the Electric Department customer accounts section, Section 8.8 of this decision, are equally applicable to the Gas Department. Therefore, we will follow the same reasoning we adopted for the Electric Department and keep the discussion of the following accounts to a minimum.

16.6.1 CPUC Account 902 (PG&E Account 1971): Meter Reading Expenses

The disagreement between PG&E and DRA on this account is $408,000 due to customer growth estimates of PG&E. As we did on Electric Department side of the house, we will adopt DRA's recommendations.

16.6.2 CPUC Account 903 (PG&E Account 1972): Customer Contracts and Orders

This account includes the labor and other costs for positions assigned to offices or to the field, for handling customer inquiries, service requests, energy cost inquiries, and other requests made by telephone or in person. In this account, PG&E requests an increase of $225,000 for customer growth, $969,000 for changing its accounting procedures for general conservation cost inquiries, and $781,000 for meeting the demands of cultural and language diversity. Consistent with what we have done on the Electric Department side, we will allow PG&E its requested increase changes to its accounting procedures as requested. We disallow the customer growth request. As to the $781,000 requested for cultural and language diversity, we will lower that amount to $400,000, reducing it by $381,000, similar to what we did for the Electric Department.

16.6.3 CPUC Account 903 (PG&E Account 1973): Customer Billing and Accounting

This account includes labor and other costs for positions assigned to analyzing rates to assist customers in choosing the correct or most advantageous rate schedule. Also included are the costs associated with order processing, teleprocessing, and bill preparation. For this account, for the gas side, PG&E seeks increases of $3,279,000 to rewrite its customer information computer program (CIS) and $232,000 for customer growth.

For reasons discussed in the electric side of the house, we reject PG&E's increases.

16.6.4 CPUC Account 903 (PG&E Account 1975): Collecting Expenses

This account includes the labor and other costs for employees assigned to credit and collection work. The increase sought is for customer growth, $305,000 for this account. As we have done in most of the other accounts, we will authorize DRA's requested increase for customer growth.

16.6.5 CPUC Account 905 (PG&E Account 1976): Miscellaneous Customer Accounts Expense

This account records the labor and other expenses resulting from positions which cannot be categorized in other activities. PG&E seeks an increase in connection with this account of $539,000 for communications to customers of payment options and $404,000 for evaluation and analysis of customer service programs. For the same reasons set forth in the discussion for the Electric side of this account, we will authorize the $404,000 for evaluation and analysis of customer services programs. We will disallow the requested $539,000 for the Gas Department portion of the communications to customers of payment options. As we have already stated, we believe that customer communication is already being handled adequately by the company. In fact, our approval of PG&E's requested increases for customer growth should take care of any need in this area.

16.7 Gas Administrative and General Expenses

PG&E's estimate of $239,940,000 for Gas Department administrative and general expenses exceeds DRA's estimate of $180,919,000 by $59,021,000.[7] For virtually all of the A&G accounts there are no differences between the arguments made for the Electric Department and the Gas Department. Therefore, we will follow the policies set forth in the Electric Department discussion of A&G accounts. In the sections to follow, we shall merely point out the dollar amounts that are affected by the policy decisions we have already made for A&G expenses generally. In Account 930.2, we will discuss the merits of the membership in the American Gas Association, which has not been addressed yet in this decision.

16.7.1 Account 920--Administrative and General Expenses

PG&E's estimate of $49,335,000 for the Gas Department portion of Account 920 exceeds DRA's estimate of $46,674,000 by $2,661,000. We have previously rejected DRA's disallowances for the following areas: application of the allocation factor from the Diablo Canyon Use Studies, and DRA's proposal regarding the PIP adjustment. The differences between the parties to the Equal Opportunity Purchasing Program costs were resolved during the Update hearings. We will disallow DRA's recommendation of $17,000 due to the exclusion of the family benefit coordinator position.

7 This numbers do not reflect the EOPP stipulation reached during the Update hearings.

16.7.2 Account 921--Office Supplies and Expenses

PG&E estimated a total of $43,547,000 for the Gas Department portion of Account 921. This estimate exceeds DRA's recommendation by some $7 million. As we did in the Electric Department side for this account, we will adopt DRA's recommended disallowance for the child care center funding of $79,000. We refer the reader to the sections for the Electric Department.

16.7.3 Account 922--A&G Expenses Transferred Credit

Account 922 is credited with the expenses recorded in Accounts 920 and 921 which are transferred to CWIP. As with the Electric Department, PG&E and DRA agree on the method to be used to determine Account 922. Both agreed the allocation to construction credit represented by Account 922 should be developed by multiplying the total of Accounts 920 and 921 by a factor of 18.2%. Such a calculation is reflected in the tables attached to this decision.

16.7.4 Account 923--Outside Services Employed

PG&E's estimate for the Gas Department portion of Account 923 exceeded DRA's estimate by $2,481,000. In keeping with our decisions made during our discussion on the Electric Department side of this account, we will disallow $1,667,000 due to our agreement with DRA's exclusion of PG&E's request for increased outside legal services. The other DRA disallowance which we will adopt in this account is for software and consultant services requested by PG&E for the development of investor lists. We believe the WMBE issue stated for this account was resolved during the Update hearings.

16.7.5 Account 926--Employee Pensions and Benefits

This topic is already received enough attention in this decision. We refer the reader to Section 9.6. PG&E and DRA were originally some $14.8 million apart for this account. However, most of DRA's recommended disallowances have been rejected. We will adopt as we did for the Electric Department, DRA's recommended disallowance of $1,245,000 for exclusion of PG&E's request for funding for its Blueprint for Learning program.

16.7.6 Account 930.2--Miscellaneous and General Expenses

For the Gas Department, PG&E's estimate of $15,212,000 exceeds DRA's estimate by $2,047,000. We will discuss the difference related to research and development being $1,185,000 of the difference, in the RD&D section of the decision. We will allow the $406,000 PG&E requests for an increase in bank line of credit fees, as we did for the Electric Department. Likewise, we will allow PG&E's membership in the California Roundtable and the Federated Employers of the Bay Area, amounts of $6,000 and $2,000, respectively.

Finally, we will address the dues for the American Gas Association (AGA). PG&E requests $785,000 for AGA dues while DRA recommends only $362,000 of those dues be paid for by ratepayers. This difference of $423,000 is due to the portion of AGA dues which DRA asserts should be disallowed as advertising and lobbying related to gas consumption and the institutional position of AGA and the gas utility industry.

First of all, PG&E points out that it agrees that $38,000 of total AGA dues should be disallowed and therefore did not include it in its request. This is the portion, according to PG&E, of AGA's media communications program and lobbying program which specifically supports lobbying efforts aimed at promoting gas consumption or enhancing the image of AGA or the gas utility industry. PG&E argues that the remainder of the disallowance obtained in the last GRC decision is inappropriate, as the bulk of activities within AGA's media communications program and legislative program support conservation and consumer cost reductions.

DRA maintains that the methodology applied in the last GRC decision to disallow AGA dues related to advertising is appropriate. In this case, DRA also increases the disallowance for dues related to lobbying to 10.5% of total AGA dues. (34 CPUC2d 199, 288.) For AGA dues, as we were for Edison Electric Institute dues, we are persuaded that PG&E has made an adequate showing in this proceeding to get us to alter what we did in the last GRC. We believe PG&E has shown that the amount disallowed in the last GRC should not be the rule for this GRC.

We agree with PG&E that AGA's research and information efforts in the arenas of conservation, consumer cost reduction, and government relations have potential benefits to ratepayers and shareholders alike. Many such industry activities can be performed more efficiently and effectively at the collective or national level than by an individual utility. These activities are performed collectively by AGA at a lower cost than individual utilities could achieve. Once again, we find that these memberships are legitimate cost of service which under a regulatory scheme should be a recoverable cost for PG&E. Therefore, we will adopt PG&E's estimate for AGA dues for Test Year 1993.

16.7.7 Account 931--Rents

Once again the issues for this account are the same as on the Electric side of the house. The difference between the parties for the Gas Department portion of Account 931 is $91,000, due to a difference regarding the percentage of computer center expenses to be charge to Diablo Canyon. As we have already found, we will adopt PG&E's allocation factor of 14.87%. There are no other unresolved issues for Account 931.

16.8 Gas Plant and Rate Base

The parties have resolved all but two issues relating to gas plant and rate base. The first area of disagreement relates to the gas pipeline replacement program. DRA has recommended a reduction of $17,671,000. Once again, this recommended disallowance was based on DRA's concern about unit costs of the GPRP program. This DRA disallowance was presented by two different DRA witnesses. Nearly $5 million of this disallowance was not even described in the DRA report. In fact, on June 1, 1992, PG&E saw for the first time a memo written by DRA's witness describing his proposed reductions to PG&E's GPRP plant estimate. However, neither this memo nor any other evidence to support this recommendation has been placed in the record by DRA. For some reason, DRA went on to incorporate this reduction in its gas plant estimate.

Given our rejection of DRA's recommended disallowances in the O&M side for the GPRP program, it follows that we should likewise reject its recommendation on the plant side. We disagree with DRA that the unit costs of doing the pipeline work will necessarily decrease. In fact, it seems clear to us, as we have stated in the O&M section of this decision, that in all likelihood the costs would be on the rise given the neighborhoods that the replacement program must now move into in San Francisco. Likewise we are disconcerted by DRA's handling of the recommended disallowance for GPRP plant. It seems to be a fairly minimal requirement that DRA make clear what its disallowance is for, instead of just including it in a line item in a table. We will adopt PG&E's numbers for GPRP plant.

The second area where there is still disagreement between PG&E and DRA relates to clear air vehicles, specifically the compressed natural gas stations on customer-owned sites. This issue, like all other issues relating to clean air vehicles, will be discussed in a later section of this decision.

Finally, there is one further area that should be mentioned. During hearings, DRA abandoned its recommendation for a recorded adjustment for the gas pipeline replacement program of some $21 million. Since DRA has dropped that recommendation, we need not go into it in greater detail here. However, for anyone who examines the Comparison Exhibit, that abandonment of that recommendation is not reflected in the Comparison Exhibit. Given the record on the subject, we are pleased that DRA chose to withdraw this recommendation.

16.9 Other Issues

All issues relating to taxes, depreciation, working cash, materials, and supplies are the same as they were for the Electric side of the house and will therefore not be discussed again. The attached tables and charts to this decision shall reflect a consistent treatment for these areas between the Gas and Electric Departments.

17. Hazardous Waste

There is currently no disagreement between PG&E and DRA regarding the level of hazardous waste funding. PG&E accepted some of DRA's changes in order to reach agreement. The major expense project deleted from the test year estimate was the contaminated oil cleanup for the Electra powerhouse. DRA's recommendation was to use the advice letter process known as the Environmental Compliance Mechanism (ECM) for this particular project. PG&E accepted this recommendation. DRA agreed that with this removal of the Electra powerhouse cleanup expense, no differences remain between the parties. (RT 25:2093.)

PG&E, in its opening brief, requests two findings from the Commission. First, PG&E requests that the Commission authorize the capital and expense levels for hazardous waste management as agreed to during hearings. Second, PG&E requests that the Commission provide for workshops following the decision in this GRC, in time to provide guidance prior to the next PG&E general rate case, to discuss modifications in the ECM, which will allow the utility expedited approval to spend funds on any phase of hazardous waste projects which are not covered by base rates. PG&E believes these workshops should include discussion of how dollars for preliminary assessment of ECM projects should be recovered, whether there is sufficient certainty about major project cleanup activity to begin to include hazardous waste cleanup projects in base rates at some average level of activity reasonably expected to occur, and whether the review of the reasonableness of such expenditures need to occur in separate proceedings with the resulting demands on Commission staff and hearing time, or whether they should be consolidated with general rate case proceedings.

We believe that PG&E raises important issues which must be addressed to ensure the evolution of an appropriate regulatory framework for determining rate recovery of hazwaste cleanup expenses. No party followed the ALJ's direction to comment on PG&E's proposal for modification in the ECM or any of the other workshop proposals PG&E made. In D.92-11-030, however, we solicited comments on potential ratemaking alternatives to reasonableness review of hazwaste expenses. We will receive those comments in the first quarter of 1993 and therefore, at this time, decline to order the workshops which PG&E requests. However, our direction in D.92-11-030 was sufficiently broad to permit PG&E, and any other interested party, to address in the comments to be filed in that docket the remediation issues which PG&E has raised here.

## 18. Research Development and Demonstration

### 18.1 Overview

At long last we have reached an area where parties other than PG&E and DRA participated. The California Energy Commission (CEC) provided three witnesses in the area of RD&D. In addition, Seimens Solar Industries provided a witness in this field. We have carefully considered the testimony, exhibits, and arguments of all the parties who participated in this field.

PG&E is requesting $61.157 million for Test Year 1993 RD&D expenses. DRA's recommendation is $50.676 million for Test Year 1993, a difference of $10.481 million. The CEC and PG&E are separated on their recommendations by $1.12 million. The major areas of differences between PG&E and DRA are in advanced energy systems RD&D, $7.3 million, customer systems RD&D, $2.8 million, and in research policy and planning, $320,000.

PG&E is also requesting that the Commission allow that an additional $35 million to be spent during 1993 through 1995 for demonstration projects qualified for capital treatment. For Test Year 1993, PG&E has requested $4.2 million in end-of-year plant additions. (Exhibit 72.) DRA has recommended no funding for demonstration projects in its plant estimate. CEC, while supporting the demonstration projects proposed by PG&E, recommends that all proposed capital projects be expensed.

As to the recommended disallowances by DRA, we adopt them in total. We will discuss each disallowance in the sections that follow. First, however, we will address the issue of the appropriate RD&D funding range and limitations on shifting the funds. We include a table showing the parties' recommendations and our adopted numbers.

# Table 1

Test Year RD&D Expenditures
(Thousands of 1990 $)

| Line | Project | PG&E Expense (1) | PG&E Total Capital (2) | PG&E 1993 Capital (3) | DRA Expense (4) | DRA Total Capital (5) | ADOPTED Expense | ADOPTED Total Capital |
|---|---|---|---|---|---|---|---|---|
| 1 | Solar Thermal Development & Testing | 1,233 | | | 635 | | 635 | |
| 2 | Wind Development & Analysis | 600 | 9,465 | 4,204 | 100 | 0 | 100 | 0 |
| 3 | System Storage Development | 1,233 | | | 50 | | 50 | |
| 4 | Photovoltaic Development & Testing | 300 | | | 50 | | 50 | |
| 5 | PVUSA (incl. Dist. Utility PV-Grid Project) | 3,300 | | | 1,000 | | 1,000 | |
| 6 | Hybrid Energy Systems | 967 | | | 967 | | 967 | |
| 7 | Advanced Thermal Generation | 1,167 | | | 1,017 | | 1,017 | |
| 8 | Strategic Studies | 900 | | | 50 | | 50 | |
| 9 | Fuel Cell Engineering, Scaleup & Demo | 0 | | | 0 | | 0 | |
| 10 | Fuel Cell R&D at PG&E Test Facility | 3,000 | | | 500 | | 500 | |
| 11 | Distributed Utility: Customer Sited PV | | 870 | 0 | 0 | 0 | 0 | 0 |
| 12 | Distributed Utility: Mod Gen Sets | | 5,172 | 0 | 500 | 0 | 500 | 0 |
| 13 | Distributed Utility: Batteries | | 4,417 | 0 | 500 | 0 | 500 | 0 |
| 14 | Total Advanced Energy Systems | 12,700 | 19,924 | 4,204 | 5,369 | 0 | 5,369 | 0 |
| | | | | | | | | |
| 15 | Advanced Computing Technologies | 485 | | | 485 | | 485 | |
| 16 | Improve Geysers Power Plant Availability | 372 | | | 372 | | 372 | |
| 17 | Power Plant Heat Rate Improvement | 813 | | | 813 | | 813 | |
| 18 | Operations & Maintenance Support | 748 | | | 748 | | 748 | |
| 19 | Power Generation System Operations | 315 | | | 315 | | 315 | |
| 20 | Avanced Hydro | 667 | | | 667 | | 667 | |
| 21 | Total Power Plant Systems | 3,400 | 0 | 0 | 3,400 | 0 | 3,400 | 0 |
| | | | | | | | | |
| 22 | Electric Distribution System | 1,723 | | | 1,723 | | 1,723 | |
| 23 | Energy Systems Integration | 1,590 | | | 1,590 | | 1,590 | |
| 24 | ED&C Planning & Development | 440 | | | 440 | | 440 | |
| 25 | Gas System | 1,617 | | | 1,617 | | 1,617 | |
| 26 | Electric Transmission System | 1,130 | | | 1,130 | | 1,130 | |
| 27 | Total Energy Delivery & Control | 6,600 | 0 | 0 | 6,600 | 0 | 6,600 | 0 |
| | | | | | | | | |
| 28 | Commercial Energy Efficiency | 1,217 | | | 851 | | 851 | |
| 29 | Industrial/Agricultural Energy Efficiency | 1,190 | | | 728 | | 728 | |
| 30 | Residential Energy Efficiency | 1,070 | | | 421 | | 421 | |
| 31 | Power Quality/Electronics/Motors | 1,010 | | | 758 | | 758 | |
| 32 | Transportation | 1,355 | | | 885 | | 885 | 0 |
| 33 | Customer Systems Planning | 388 | | | 287 | | 287 | |
| 34 | Food Service Technology Center | 240 | | | 240 | | 240 | |
| 35 | ACT2 for Maximum Energy Efficiency | 3,000 | | | 3,000 | | 3,000 | |
| 36 | Total Customer Systems | 10,000 | 0 | 0 | 7,170 | 0 | 7,170 | 0 |
| | | | | | | | | |
| 37 | Fossil Emissions & Waste Reduction | 1,567 | | | 1,567 | | 1,567 | |
| 38 | Geysers Emissions & Waste Minimization | 253 | | | 253 | | 253 | |
| 39 | Natural Resources Management | 1,200 | | | 1,200 | | 1,200 | |
| 40 | Health & Safety Tech Development | 680 | | | 680 | | 680 | |
| 41 | Total Environ. Health & Safety | 3,700 | 0 | 0 | 3,700 | 0 | 3,700 | 0 |
| | | | | | | | | |
| 42 | Research Contributions | 19,067 | | | 18,747 | | 3,780 | |
| 43 | Program Management & Administration | 5,433 | | | 5,433 | | 5,433 | |
| 44 | Performance Incentive Plan (PIP) | 257 | | | 257 | | 257 | |
| 45 | Total Research Policy & Planning | 24,757 | 0 | 0 | 24,437 | 0 | 9,470 | 0 |
| | | | | | | | | |
| 46 | Total | 51,157 | 19,924 | 4,204 | 50,676 | 0 | 35,709 | 0 |

(1) Exhibit 80 - Revised PG&E Table 1-1
(2) Exhibit 80 - Revised PG&E Table 2-5
(3) Exhibit 72 - Revised Differences Between PG&E and DRA Plant Positions
(4) Exhibit 145 - Revised DRA Table 3-4A
(5) Exhibit 109 - DRA Report on RD&D, Chapter 4

Finally, we note that the Legislature has provided direction on the circumstances under which RD&D projects may be undertaken and the appropriate funding for RD&D projects in the PU Code.[8]

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8 PU Code Section 740.1 provides:

"The Commission considers the following guidelines in evaluating the research, development, and demonstration programs proposed by electric and gas corporation.

"(a) Projects should offer a reasonable probability of providing benefits to ratepayers.

"(b) Expenditures on projects which have a low probability for success should be minimized.

"(c) Projects should be consistent with the corporation's resource plan.

"(d) Projects should not unnecessarily duplicate research currently, previously, or intelligently undertaken by other electrical or gas corporations or research organizations.

"(e) Each project should also support one or more of the following objectives:

"(1) Environmental improvement.

"(2) Public and employee safety.

"(3) Conservation by efficient resource use or by reducing or shifting system load.

"(4) Development of new resources and processes, particularly renewable resources and processes which further supply technologies.

"(5) Improve operating efficiency and reliability or otherwise reduce operating costs."

18.2 RD&D Funding Range

The issue of selecting an appropriate funding range for RD&D is derived from a prior Commission decision. In D.90-09-045, we required that the utilities provide for maximum and minimum RD&D levels for their next general rate case. The funding range means that, if the utility's rate request for RD&D spending is within the funding range ordered in the current rate case, PG&E would focus the discussion of RD&D on broad RD&D program directions. Only when the utility's RD&D program rose above the ceiling or fell below the floor would detailed information be required. PG&E points out that in return for this, it and other utilities are today providing more detailed annual reports. The theory is that the utilities report in more detail in their annual RD&D reports and less information would be required in the GRCs as long as the utility is within the funding range. PG&E correctly points out that this program does not preclude DRA or other Commission staff from utilizing data requests when more information is needed. Our goal was to give management discretion to manage within a reasonable floor and ceiling and not to micromanage the utilities' RD&D programs from a zero-based perspective in every GRC. (37 CPUC2d 390, 393).

Therefore the issue before us is to select the appropriate funding range which would be PG&E's guideline in its next general rate case. PG&E has recommended a funding range of between 0.75% to 1.25% of its gross operating revenues (GOR) to be set by the Commission as the floor and ceiling for PG&E's RD&D program in the 1996 GRC. DRA, on the other hand, has recommended a range from 0.6% to 0.8% of the GOR.

PG&E argues that DRA's range is too narrow. PG&E argues that with the modified annual report format and a biennial report by CACD, there is more than adequate information available to the Commission to authorize a funding range more in line with PG&E's recommendation. PG&E contends that DRA's reluctance to allow a broader funding range indicates a reluctance to move away from zero-based budgeting approach RD&D is put through in every GRC. DRA, on the other hand, is concerned that if PG&E's proposal is adopted, it will need to provide only minimum justification for RD&D expenditures up to $125 million or, more than twice its 1992 authorized budget. That level of undocumented expenses is simply excessive. DRA argues that PG&E's request would constitute no Commission management, if PG&E provides no thorough RD&D documentation until its budget level doubles from current standards.

On this issue we believe the most reasonable approach is to set a funding range in between the recommendations of DRA and PG&E. We agree with PG&E that DRA's range is a bit narrow. However, we are concerned about going to as high a level as PG&E has recommended for some of the reasons stated by DRA. Therefore, in the spirit of compromise, we will set the funding range from 0.6% to 1.0% of GOR for PG&E's 1996 GRC showing. We believe this range would give PG&E adequate flexibility because we do not desire to micromanage its RD&D programs, yet not go so high as to relinquish our obligations to monitor utility activities.

18.3 Shifting of Funds Within the RD&D Program

DRA has recommended that PG&E be subject to the same rules regarding limitations on shifting funds within its RD&D budget that we now require of Edison and SDG&E. PG&E believes that these funding shift guidelines are unreasonable to apply to PG&E because PG&E has never behaved in the way regarding RD&D that has caused the Commission concern.

The program funding guidelines regarding shifting are as follows: PG&E could redirect 20% of its program funding without further Commission authority, 20 to 50% if the Commission grants an advice letter request, and above 50% if the Commission grants a request by application. These are the same restrictions placed on the other utilities.

DRA argues that all utility RD&D programs should be subject to the same regulatory requirements. DRA claims that it is merely due to the GRC process that such regulations inevitably become a requirement of each utility one at a time. DRA argues that the rationale for a limitation on funding shifts ensures that utilities will not receive RD&D money for certain purposes, and then spend the money, without constraint, on another entirely different RD&D program.

PG&E counters these arguments by stating that it has always been sensitive to the flexibility and management discretion allowed by the Commission for RD&D over its last three GRCs. PG&E claims that it has never attempted to shift large amounts of dollars within its programs, if it represented a major change to what was authorized in its prior GRC decision. Further, PG&E states that any changes which were made have been reported in its annual RD&D report to the Commission. PG&E states that there has been no negative feedback for its company regarding any changes PG&E has made to funding of its RD&D work in the past. (RT 26: 2251-2252.) PG&E concludes that it does not want to be penalized because other utilities have behaved unreasonably in this area.

By putting these shifting of funds restrictions on PG&E also, we are not suggesting that PG&E has at all behaved in an inappropriate fashion regarding shifting of RD&D funds. We agree with DRA that it is appropriate that each utility be dealt with in a similar fashion regarding its RD&D programs. We also note that because PG&E has never attempted to shift large amounts of dollars, these guidelines, which are reasonable, should not be a burden on PG&E. If PG&E finds that these guidelines are a burden to it during this rate case cycle, we will revisit the issue in the next GRC and consider a change if PG&E can make a showing that it is necessary. For now, we will adopt DRA's recommendation to apply the same shifting of funds requirement for PG&E that is currently applicable to Edison and SDG&E. Although somewhat restrictive these guidelines still give the utilities the flexibility and management discretion to redirect funds to meet overall strategy and RD&D program needs.

18.3.1 One-Way RD&D Balancing Account

We believe it is helpful, at this point, to add to our discussion of funding by reiterating our guidelines on the one-way RD&D balancing account. In D.87-07-021, we adopted the balancing account to ensure that authorized funding for RD&D was either spent on RD&D or returned to ratepayers. In that decision, we stated:

> "We direct PG&E to maintain a separate account for RD&D funding. The amount authorized in rates will be a ceiling. Funds unexpended at the end of each year will accrue interest at the short-term paper rate. Within a rate case cycle, funds not used in one year may be used in subsequent years." (D.87-07-021, p. 4.)

We also wish to add that we believe it is appropriate for PG&E to apply annual overexpenditures to the balancing account such that at the end of the three-year cycle, any unspent funds would be returned to ratepayers in the form of a credit to the ERAM balancing account. In this way, we preserve the principal of returning unspent funds while maintaining flexibility in the timing of research expenditures.

## 18.4 Advanced Energy Programs

### 18.4.1 Solar Project Funding

PG&E is requesting approximately $1.2 million for this area, while DRA believes that $635,000 is a reasonable estimate for expenses for solar project funding. DRA points out that a major portion of PG&E's RD&D request for solar research has been withdrawn due to the bankruptcy of one of the research participants, Luz Solar, which casts a major shadow over the future of the research project.

DRA has no disagreement with the funding PG&E seeks for solar research related to central receivers and disk systems. The area of controversy pertains to PG&E's proposed research on a solar trough. DRA points out that PG&E's request for solar trough project expenses is tied to the Third Phase of a solar plant demonstration. This Third Phase of the project has already been delayed two years from 1993 to late 1995 because of the Luz bankruptcy. Accordingly, DRA believes it is reasonable to also eliminate the solar expenditures for the Third Phase at this time. DRA believes it is only reasonable to fund Phase 1 and Phase 2 of the solar trough project because they are expected to be incurred in 1993 and 1994. PG&E counters that the funding level advocated by DRA is inadequate to do the testing and analysis work required to determine the technical viability of proceeding with a utility-scale demonstration of advanced trough technology.

We are unpersuaded by PG&E's showing on this item. We agree with DRA that the timing slippage resulting from Luz's bankruptcy does alter what is a reasonable request for this project. We believe that we are providing an adequate funding level for PG&E to proceed in this area.

### 18.4.2 Wind Development

DRA's recommended disallowances in the field of wind development relate both to expense requests and PG&E's desire to capitalize its wind turbine demonstration.

PG&E seeks to capitalize $9.465 million in the 1993 through 1995 time frame for its wind turbine demonstration project. DRA believes that none of these amounts should be capitalized. DRA believes that no wind turbine development expense, capitalized or not, should be included in rates. The project in question is a several phase project totaling some $17 million. PG&E intends to contact turbine manufacturers and select promising turbines for each phase. PG&E wants to buy approximately 20 wind turbines from four or five manufacturers and test them in a utility environment. PG&E wants the project to accelerate the entry of the next generation of utility grade wind turbines into the commercial market. (Exhibit 109, pp. 4-12 and 4-13.) DRA made it quite clear in its testimony under cross-examination why it believes this is an inappropriate RD&D project for ratepayer funding:

> "It is unreasonable and unnecessary for PG&E to use ratepayer funds to assist the promotion of wind turbine technology, a technology which is already competitively viable and efficient. PG&E is not supporting wind turbine development, it is financially supporting a field test of state-of-the-art wind turbines for the benefit of the manufacturers. Any research results will be limited to the discovery of relatively small operating differences in newer turbines. None of these designs are alleged or expected to be significantly more cost-effective than any of the existing turbines available. The technology of wind turbines is commercially available and reasonably advanced. This research project is not needed." (Exhibit 109, p. 4-13.)

Further, DRA characterizes this as not supporting wind turbine development but rather subsidizing a field test for the benefit of the manufacturers. DRA believes this because PG&E has no plans to require the wind turbine manufacturers to provide the turbines for the project. PG&E says that this would be a financial burden for the manufacturers. However, DRA points out that the turbine manufacturers would be the major beneficiaries of this research, because the manufacturers would learn the strengths and weaknesses of each turbine design, at no cost to them. DRA argues that PG&E has failed to demonstrate that the benefit to ratepayers is worth the cost PG&E wants to spend, or that the turbine market will be unable on its own to compile the same information.

The CEC disagrees with DRA and recommends that the Commission support PG&E's request. (Exhibit 307.)

On a $400,000 expense for U.S. Windpower Turbines, DRA also rejects PG&E's proposal. DRA does not believe that ratepayer money should be use to design, construct, test, and commercialize advanced wind turbines in a competitively viable market. DRA believes that the wind turbine market has been subsidized by ratepayers and is now healthy and competitively viable. DRA does not find further subsidies either necessary or reasonable. DRA points out that U.S. Windpower Turbines has already sold turbines to the Sacramento Municipal Utility District (SMUD) that are the same type for which PG&E seeks RD&D ratepayer funding. (Tr. 25:2138-2139.)

Once again, the CEC recommends funding this effort at $400,000 level requested by PG&E. The CEC argues that wind is an opportunity technology because it is a potentially competitive electric resource technology for California. (Tr. 31:2771.)

There is one area in the wind development field that DRA believes is a reasonable expenditure of ratepayer dollars. DRA supports a $100,000 for funding of PG&E's wind resource evaluation program. DRA states that in contrast to the other proposed items, the geographically specific identification and evaluation of wind energy production potential of various sites are reasonable. DRA believes that further work for utility-specific applications is a reasonable use of ratepayer funds. The CEC concurs in this.

Overall, we are persuaded by DRA's arguments that the level of funding which PG&E seeks to put into further wind technology development is excessive. We agree with DRA that wind turbine technology, based in part on prior research and development dollars, is now at a level of commercial viability that no longer needs the infusion of RD&D dollars by PG&E's ratepayers. Likewise, we believe PG&E's desired capitalization of these funds is inappropriate. We believe it is more appropriate for the wind turbine industry to finance additional development in this field.

### 18.4.3 Photovoltaics

There are two areas for photovoltaics which PG&E and DRA disagree on the appropriate funding level. The first area relates to photovoltaic development and testing where PG&E requests $300,000 for the development of testing of PV energy systems and the optimization of balance-of-system components. DRA believes that the $300,000 is too large a request. Rather, it believes $50,000 annually is appropriate.

PG&E is requesting $870,000 in capital for customer-sited PV demonstrations. DRA recommends no funding by ratepayers for this project. Ratepayer funds, in DRA's opinion, must not be used to promote research which favors utility services at the expense of the competitive market. (RT 26:2235-2236.)

Both the CEC and Seimens Solar Industries disagree with DRA's analysis. They argue that PG&E needs to spend the full $300,000 in order to continue to promote this technology. PG&E believes that its leadership in this area, with dollars, is justified by its resource abundance and the match of that resource with load. PG&E argues that ratepayer benefits include the general benefits of peak shaving, and location-specific RD&D upgrade deferrals.

We disagree with PG&E and its allies on this issue, finding DRA's concerns about the appropriateness of this high level of funding to be well taken. We will allow funding at the $50,000 level recommended by DRA.

The second project in the area of photovoltaics is the photovoltaics for utility scale applications (PVUSA). This is a $47 million demonstration project of which PG&E is one participant. Its purpose is to test large-scale photovoltaics systems, and to provide utilities with information about the reliability, performance, operation, and maintenance costs associated with a utility grid-interconnected photovoltaic system. This project began in 1986 and is scheduled for completion in 1995. PG&E is requesting $3.3 million for Test Year 1993 for this project and its grid-connected PV demonstration project at its Kerman substation. The U.S. Department of Energy (DOE) will pay about 50% of PVUSA's costs. Other than DOE, PG&E says that co-funding by other parties will reach only 8% of total costs. PG&E forecasts that its own contribution to PVUSA total costs will reach 48% by the time the project is completed.

DRA disagrees that PG&E should carry such a high percentage of the project costs for PVUSA. DRA recommends that the Commission limit PG&E's ratepayer funding in PVUSA to $500,000 for Test Year 1993. DRA points out that that level of funding will allow PG&E to aggressively participate in PVUSA as a 30% participant, which is a higher level of participation than PG&E's 1992 forecast of 27%. (Exhibit 109.) DRA argues the level of co-funding from other parties is very low. DRA points out that PG&E has made no forecast of funding from EPRI, SDG&E, or Edison. DRA states that all of these entities can benefit from PVUSA as much as PG&E.

PG&E argues that it will make every attempt to minimize the actual funding by PG&E in all of its photovoltaic research. The CEC believes PG&E should be funded at its requested level, arguing that PG&E is the natural leader for the PVUSA project. Not surprisingly, Seimens Solar Industries, a company that stands to benefit from any research done by ratepayers in this field, agrees that PG&E should be funded to the level it requests.

Once again, we must balance our desire and support to move forward with research in these important new technologies and our concern over the fairness of how much ratepayers should be asked to pay to support this research. We find persuasive DRA's arguments that funding at a 30% level for Test Year 1993 is clearly a reasonable amount for one utility to be expected to fund. Since PG&E seems to be confident that other co-funding will materialize, even though it could not be definitively committed to for purposes of this GRC, we believe that our reduction in PG&E's request will not slow down the PVUSA progress. Rather, it will motivate PG&E and other participants to seek co-funding from the other interests in this field who stand to benefit from the overall success of the project. Therefore, we will allow DRA's recommended $500,000 amount for the PVUSA project for Test Year 1993.

#### 18.4.4 Fuel Cell Engineering

PG&E has withdrawn its request for $3.5 million for development of a fuel cell, in cooperation with the City of Santa Clara. The proposed development was for a 2-megawatt facility. PG&E became concerned that a facility of that size was not yet ready to move forward, and requested the other project participants to agree to a delay pending further testing. Because the other participants wanted to move forward, PG&E withdrew its participation. DRA concurs with PG&E's withdrawal from this project. However, as to other fuel cell issues, PG&E and DRA disagree.

PG&E has requested an increase in its funding for smaller fuel cell research above the level requested in its application. Originally, PG&E requested $1.1 million and has now raised that request to $3 million. PG&E requests the additional money for increased testing of a 70-kilowatt unit, a 100-kilowatt unit, a 100-kilowatt production unit, and a 200-kilowatt unit. (RT 25:2111-2116.)

DRA, on the other hand, believes that ratepayer funding should be limited to $500,000 for several reasons. First, DRA points out, that the research and development of the smaller units of these fuel cells is sequential and conditional, meaning, that PG&E must build its larger unit only after the smaller unit is successfully tested. DRA believes PG&E's planned schedule for moving forward with this development is overly optimistic. DRA points out that successful testing of the smaller unit is a prerequisite to beginning the next project level. PG&E's witness admitted that problems at any stage in this process can delay the next stage of testing. (RT 25:2115.)

DRA argues that RD&D funding which assumes that the entire sequence of fuel cell testing will be perfectly timed and successful is unrealistic and inappropriately expensive. In addition, DRA objects to the fact that PG&E assumes almost no funding for this project from non-PG&E sources. During hearings, PG&E's witness said that perhaps $200,000 or $300,000 in co-funding would be available. However, during 1991 PG&E received $746,000 from EPRI in co-funding for fuel cell testing and $70,000 from the CEC. For 1992, PG&E has budgeted $600,000 from EPRI for fuel cell testing, a $120,000 from the CEC, and $600,000 from GRI totalling $1.32 million in fuel cell testing co-funding. While none of these amounts represent checks in the mail, DRA believes that the co-funding will be substantially more than what PG&E has stated. (Exhibit 144, RT 25:2124.)

Once again the CEC supports PG&E's plans to pursue this activity. PG&E also raises the argument that its proposed program is different than that of an ongoing project of SDG&E. PG&E points out that it has constructed a pilot MCFC powerplant in its San Ramon Technology Center as a vehicle to begin the investigation of integrated fuel cell powerplant issues, albeit at the single stack level. PG&E points out that this program is different than the 200-kilowatt project which SDG&E intends to participate in. PG&E argues that substantial technical differences in stacks from the two suppliers necessitate major differences in associated equipment, different and complementary lessons on integrating stacks into generating units will therefore be learned from the two efforts.

Our adoption of DRA's recommendation for this project is not based on the fact that this project as proposed by PG&E is redundant of the SDG&E project that is ongoing. Rather, we find DRA's concerns regarding the likelihood of timing to be persuasive. PG&E has not provided us with adequate assurances that its schedule is realistic. We remind PG&E that the burden is on it to justify the dollars requested, not on DRA. Likewise this is another area where we believe PG&E needs to be given an incentive to aggressively seek as much co-funding as possible from other participants. We will adopt DRA's recommended $500,000 level for fuel cell engineering.

18.4.5 System Storage

PG&E's energy storage research is in superconducting magnetic energy storage (SMES), compressed air energy storage (CAES), and hydroelectric. PG&E states that its project objective is to evaluate and assess other storage options and is requesting $1.233 million for this research. PG&E believes that storage will be increasingly necessary as renewable (nondispatchable) resources, primarily having energy value as opposed to capacity, are added to the system. The primary focus of PG&E's research is on the compressed air energy storage.

DRA disputes that it is appropriate for PG&E to go forward with this level of funding for this field at this time. DRA points out that there is no reasonable opportunity for storage economics to become cost-beneficial to ratepayers any time in the near future. DRA points out that PG&E has not presented any evidence in this proceeding that storage is marginally economic or even beneficial to ratepayers. Furthermore, PG&E has not determined that its storage fields are geologically capable of containing compressed air storage. DRA concludes "given the uneconomic cost of storage, the Commission declaring that wind is a resource that is deferrable by QFs, and the added cost of transmission losses this project would bring, it is unreasonable for PG&E to research a storagewide powerplant that has no prospect of being built by PG&E given the Commission's resource bidding process." (Exhibit 109, pp. 3-8 and 3-9.)

PG&E counters this argument by stating that one of the purposes of the testing is to determine the geological conditions of the depleted gas reservoirs that are being considered for this storage program. CEC points out that it is offering the co-funding level for the CEAS program of $400,000. Once again, CEC has recommended that PG&E get the full funding levels it has requested.

We share DRA's concern that this level of spending by PG&E is premature for the system storage programs. We note that the CEC as it has with other issues is in favor of funding PG&E's requested levels. However, this Commission has considerations beyond those which are in CEC's jurisdiction. That is, this Commission must consider the overall impact of these programs on the ratepayers who are being requested to pay for them in these tough economic times. Therefore, we will grant only the amount of funding that DRA has recommended for system storage programs. Once again we encourage PG&E to seek out additional co-funders in order to proceed if it chooses to do so with the projects as it has structured them thus far. .

18.4.6 Advanced Thermal Generation

Overall, in this area, PG&E requests $1.167 million while DRA suggests a reduction of $150,000, allowing $1.017 million. PG&E points out that high efficiency gas conversion has the potential to develop technologies which will be significantly more efficent than existing technologies and they have the potential to reduce fuel costs by one-third or more. In fact, if the technology existed for use in today's fossil plants, the amount of savings would be roughly $300 to $500 million per year in fuel costs alone. (RT 25:2102-2103.)

PG&E and DRA agree on the advanced repowering studies at $800,000, the advanced geothermal and biomass study at $117,000, and advanced thermal generation exploratory research at $50,000. The area of disagreement relates to the advanced aeroderivative turbine demonstration where PG&E requests $200,000 and DRA recommends only $50,000.

PG&E contends that DRA's funding level will not allow this effort to proceed as planned and may send a signal to the gas turbine vendors that the California utilities are not interested in this technology. However, PG&E lists several other participants in what will likely be a California demonstration project. The other participants are Edison, EPRI, GRI, SDG&E, SoCalGas, SMUD, Los Angeles Department of Water and Power (LADWP), and the CEC. It seems reasonable to once again assume that the other participants can perhaps add to their level of participation rather than burdening PG&E's ratepayers so heavily. The CEC once again believes that PG&E should get its full request arguing that the benefits would far outweigh the investment. (RT 31:2776.)

Once again, in our efforts to balance the need to pursue RD&D and our obligation to protect PG&E's ratepayers from unnecessary expenses, we believe DRA's recommendation of the funding level for advanced thermal generation is appropriate.

18.4.7 Strategic Studies

PG&E has requested $900,000 for this line item with DRA recommending only $50,000. PG&E argues that because it cannot realistically participate in all R&D efforts, it does need to maintain an awareness of what is being done by others. This effort scans for new technology, screens them for application by PG&E, determines who is leading the R&D effort, and continuously assesses the technology development and compares the projected costs of the energy produced from new technology with existing technologies. As to be expected, the CEC joins PG&E and its full level funding request. PG&E believes that DRA's recommended level of $50,000 is unreasonably low, barely covering one-half of the person's time.

DRA justifies its reduction for strategic studies on the ground that ratepayers should not be funding an attempt to refine research costs when it is actually the market which will determine which products are eventually built. Further, DRA believes that much of this research is done as part of other ongoing projects. DRA believes that any additional research that needs to be done could be conducted by a research professional or perhaps student interns under guidance. (Exhibit 109.)

We will adopt DRA's recommendation for strategic studies. We are concern that PG&E has not adequately justified these dollars requested for the different pieces of strategic studies. Once again we point out that the burden for RD&D development in California is not on PG&E alone.

18.4.8 Lake County Wastewater Pipeline Project Proposal

While this issue is being discussed in the context of PG&E's RD&D, we note that the issue was brought before us by the County of Lake rather than PG&E. We will discuss the overall project in a later section of this decision. However, it relates to RD&D in that CEC argued that the dollars requested by County of

Lake for this project could perhaps be included in RD&D dollars. However, PG&E contends that this project requires a significant long-term financial commitment and does not fit the FERC definition of RD&D. In its brief, PG&E proposed that an additional $300,000 per year (instead of the $2 million requested by County of Lake) would be more appropriate and could be reasonably used to conduct injection RD&D at the Geysers, in an effort to quantify what the actual benefits of successful injection might be. Because of the way we intend to handle this issue on its merits, we do not believe that an additional increase in RD&D research at Geysers is necessary in the context of PG&E's RD&D accounts. Therefore, we will reject the suggestion made by PG&E in its brief and deal with the rest of the Lake County requests in Section 22 to follow in this decision.

18.4.9 Customer Systems Program

Overall, these programs focus on customer-based energy efficient technologies, and so are closely related to DSM activities. PG&E's overall request in this area is $10 million, while DRA believes a funding of $7.17 million is adequate. Further, DRA recommends that the customer systems program be funded by demand-side management funds. DRA does recognize that this issue should be determined in a more appropriate forum than this GRC, namely the DSM proceeding (R.91-08-003, I.91-08-002). DRA explained that the purpose of this recommendation is to strengthen the connection between customer energy efficiency RD&D and DSM, and to improve the effectiveness of researching and developing technologies which will be of tangible benefits to ratepayers. (Exhibit 103.) We agree with DRA that while this recommendation has merit, this is the inappropriate forum for it to be resolved. We direct that this issue be addressed in our ongoing DSM proceeding.

The bulk of the differences between PG&E and DRA, some $2.83 million, are found in five programs which will be discussed below.

### 18.4.9.1 Commercial Energy Efficiency

PG&E requests $1,217,000 in this area, while DRA recommends a reduction of $366,000, leaving the total at $851,000. PG&E plans to focus on systems integration and controls in achieving energy efficiency gains for such energy uses as heating, ventilation, and air conditioning for lighting, and for vertical transport. DRA basis its recommendation for a reduction not because it does not support these programs but because of what it believes to be an overlap between this area and other existing PG&E programs. DRA explains this overlap:

> "The Commercial Energy Efficiency project especially holds the potential for overlap with the ACT2 project, since the principal focus of ACT2 has been and will continue to be on commercial buildings. The two largest proposed activities under this project are Office Energy Efficiency and Productivity Demonstrations ($515,000), and Integration of Building Control Systems ($532,000). PG&E has stated that this project differs from the ACT2 project in that it focuses on technologies and applications farther into the future, whereas ACT2 has greater near term application. Conceptually, a distinction may exist, but much of the descriptions of these two projects appear nearly identical." (Exhibit 109, p. 3-28, footnote omitted.

PG&E states that there is little overlap between PG&E's commercial energy efficiency RD&D program and the ACT2 project. However, PG&E does admit that the personnel of the two groups are housed in the same San Ramon offices so that communication is open and continuous, admitting that some overlap is inevitable as both of these efforts pass information back and forth. PG&E made no effort to define that overlap. Accordingly, DRA recommends a funding level half-way between the funding average for 1990 through

1992 and the 1993 through 1995 requested amount. This is how DRA arrived at an amount of $851,000.

DRA's compromise seems to be reasonable given that PG&E did not address the issue of overlap between ACT2 and this program adequately. We will adopt DRA's number for commercial energy efficiency programs.

#### 18.4.9.2 Industrial and Agricultural Energy Efficiency

PG&E requests $1.19 million in RD&D funding for this project. PG&E states this project will focus on component field testing, technology scanning, process optimization, and system evaluation tools. DRA, on the other hand, recommends that appropriate funding for this project should be $728,000. This number is derived from the average level of funding for this area from 1990 through 1992. DRA believes its reduction is reasonable because industrial facilities have characteristics that reduce the value of some research in this area. DRA points out the inherent complexity and nonuniformity of industrial facilities as compared to commercial customers. Likewise, DRA points out, that industrial customers' energy uses cannot be categorized as easily as commercial customers. DRA concludes that research into industrial systems is less likely to yield lessons applicable to a large number of other industrial customers. At best, DRA believes that systems optimization in the industrial sector would assist only a small number of customers. (Exhibit 109.) Finally, DRA believes its reduction in the funding level is justified because PG&E has presented a lack of clear project direction in addition to the questionable goal of industrial system optimization. PG&E responds to DRA's arguments by saying that while these customers tend to be unique, the overall funding level requested is barely 2% of all RD&D funding. PG&E points out that the CEC joins them in its requested funding level for this area.

We are unpersuaded by PG&E's arguments that it has adequately justified the level of funding it seeks. We will adopt

DRA's funding level of $728,000 for the industrial and agricultural energy efficiency program for the reasons stated by DRA.

18.4.9.3 Residential Energy Efficiency

PG&E requests $1,070,000 for this project, to further energy efficiency and load reduction by developing and applying new technologies, and to gain understanding of actual field performance of systems. DRA recommends that the funding for this area at the average level for 1990 through 1992, or $421,000. (Exhibit 109.)

DRA has several reasons for its reduced funding level recommendation. First, DRA questions the potential ratepayer benefits of the portion of the program which pertains to home automation and customer communications activities. The major impacts of this research appear to be increased customer information from the utility, increased complexity of home energy controls, and possibly the ability to effect some peak shifting. Furthermore, DRA concludes that the peak shifting would only occur with the introduction of time varying rates for residential customers.

Likewise, DRA is concerned that there is a potential overlap with the residential energy efficiency project activities within the ACT2 project. In addition, Edison is conducting similar research with its home-of-the-future program and "Smart House" prototype. DRA does not believe PG&E should duplicate these efforts.

Finally, DRA recommends its disallowance in this area because appliance testing and development has been included. DRA believes that appliance manufacturers, not PG&E, should bear the responsibility for developing advanced refrigerators and freezers. DRA believes that increased saturation with current technology holds more promise at this time. PG&E responds to DRA's argument by pointing out the Commission has already approved an advice letter by Resolution E-3229 dated May 8, 1991 to establish alternative residential time-of-use rates.

PG&E points out that its central interest in home automation and customer communications RD&D is the potential of these systems to reduce peak electric loads through the effective response to innovative pricing or other signals that may be dispatched through an advanced communication system. Likewise, PG&E states that it intends to work cooperatively with Edison. Overall, PG&E argues, DRA's recommendation considerably reduces PG&E's ability to do the work it believes is necessary in this field.

Once again, we believe that PG&E has inadequately made a showing to convince us that the level of dollars it seeks are in fact necessary and not duplicative or padded. As more of these areas actually move into residential use, we must examine carefully the dollar amounts requested for continued RD&D activities. DRA's recommendation allows sufficient dollars for PG&E to pursue residential energy efficiency programs in appropriate ways.

18.4.9.4 Power Quality/Power Electronics/Motors and Systems

PG&E recommends $1,010,000 for this area of RD&D while DRA recommends a reduction of 25%, leaving $758,000 for these activities. DRA believes that reduction was appropriate because it contends that PG&E's RD&D efforts in this area are not leveraged with other organizations. PG&E claims that in fact some leveraging will occur. A PG&E project which is leveraged with others generally entails PG&E sending money to someone else's RD&D project or consortium, where someone else collects the money from PG&E and others and manages that RD&D effort.

We find PG&E's showing on this area to be inadequate to allow the full amount requested. We agree with DRA that a 25% reduction is appropriate and encourage PG&E to seek additional funding from other sources.

18.4.10 Transportation

While the subject of natural gas and electric vehicles will be discussed in greater detail generally in the next section of this decision, the areas that pertain to the RD&D efforts and budget will be addressed here. PG&E requests a total of $1,885,000 for this RD&D area. DRA's recommendation is $885,000.

The largest area of disagreement is for funds for PG&E's support of the clean air vehicle technology center (CAVTC). DRA recommends that no funding be authorized for this program.

The CAVTC is a privately owned and operated facility located in the Bay Area which will provide an objective and credible testing and analysis facility where PG&E, other utilities, private fleet owners, and regulatory agencies (both state and federal) can go to test vehicle emissions, vehicle performance, and other parameters of alternative fuel vehicles. PG&E expects to use this facility for testing of advanced natural gas vehicles and electric vehicles. CEC joins PG&E in recommending approval of PG&E's $500,000 request for CAVTC funding.

DRA believes this is an area of research that should be funded by the competitive market or a government agency, not PG&E. We note that DRA's overall recommendation in this RD&D field for electric and natural gas vehicles is in keeping with its recommendation for that subject area. In order to be consistent with the level of funding we will approve for PG&E in this area, we will adopt DRA's recommendations for RD&D dollars for the transportation field. We note that the dollars approved should be more than adequate to continue to further support and encourage natural gas and electric vehicles in the State of California.

### 18.4.11 Research Policy & Planning

In this umbrella area, PG&E and DRA agree on $5.433 million for a program management and administration. However, for the $19,067,000 requested for contributions, DRA recommends a reduction of $300,000. In addition, we raise the issue on our own as to the appropriateness of PG&E's contributions to EPRI of $14.5 million. (Exhibit 12, p. 2-179.)

DRA recommends a disallowance of $300,000 for PG&E's support of the Gas Cold Reactor Associates (GCRA). PG&E contends that the advanced nuclear technology being developed through GCRA is a modular (110-megawatt) technology which emphasizes standardized design, for ease of mass production, and is inherently safe. PG&E believes it should continue to support GCRA's efforts as it has for the past three years. DRA disputes this saying that GCRA is not a research organization. We agree with DRA that this organization is more akin to an advocacy group than a research organization. We will support DRA's disallowance.

In addition, DRA has recommended two additional disallowances, one a $10,000 contribution to the California Construction Technology Transfer Association and the second to the California State University Foundation Research. As to the first disallowance, PG&E argues that its contribution to this entity enables PG&E's construction and engineering personnel to have access to the latest construction method technologies for a minimal investment. Likewise, PG&E believes its contribution to CSU's annual R&D support for innovative thinking by college students in a number of technological areas including energy is a reasonable ratepayer expense.

We disagree. We believe DRA's arguments that these are inappropriate contributions with ratepayer funds.

Finally, we wish to address the issue of EPRI dues. We note that these dollars constitute the major portion of the overall category of contributions.

EPRI's mission, as described by PG&E, is to discover, develop, and deliver advances in science and technology for the benefit of member utilities, their customers, and society. EPRI's research program covers a broad range of technologies related to the generation, delivery, and use of electricity with special attention paid to cost-effectiveness and environmental acceptability. PG&E anticipates that its 1993 EPRI nonnuclear contribution to be nearly $15 million. We note that in Edison's recent GRC decision, we disallowed any dollars set aside for EPRI membership. We noted in that decision that Edison's request for funding of EPRI came late in the proceeding. (D.91-12-076, mimeo. pp. 115-116.) Such is not the case here. However, we are concerned as to whether the EPRI dollars spent is the best use of ratepayers' money. We note that EPRI is a national organization, yet a large portion of its overall funding is derived from California utilities. We are concerned as to whether enough attention is given to California issues in the disbursement of these funds. PG&E did not make an affirmative showing as to what benefits accrue to California ratepayers from EPRI funds expended on dues. Therefore, we will disallow PG&E's EPRI dues for now, but will allow PG&E to make a showing on how funds expended for EPRI dues benefit California ratepayers. Since Phase 2 of this proceeding is ongoing, PG&E may make such a showing in the currently scheduled Update hearings in Phase 2. Depending on that showing, we may reconsider this disallowance. In the meantime, we do not extend program funding flexibility to EPRI dues.

## 19. Clean Air Vehicle Programs

### 19.1 Overview

PG&E, DRA, and the CEC all participated in the issue of PG&E's proposed clean air vehicle (CAV) programs. PG&E describes the programs as designed to continue development and commercialization of two of the most promising alternatives to gasoline-powered vehicles. The two alternatives are natural gas vehicles (NGVs) and electric vehicles (EVs) which PG&E believes will significantly and substantially contribute to air quality improvements. None of the parties fundamentally disagree that this area of CAVs is one that is worthwhile. The disagreement among the parties relates to two major issues: First, where should these dollars for CAV be handled and based on what policy considerations? Secondly, what level of funding is appropriate to decide in this general rate case? Both issues will be addressed below.

## 19.2 CAV Program Classification

The CEC in particular is troubled by PG&E's classification of its CAV activities under one umbrella, as they have been presented in this GRC in Exhibit 14. The CEC argues that while this may have the virtue of simplicity, it is fundamentally misguided in that virtually all of these programs are either RD&D or DSM activities and therefore should be treated as such. The CEC goes on to argue that creating a separate category for CAV activities would decrease oversight by responsible PG&E management and by regulators, and would treat PG&E's CAV activities substantially differently than those of Edison, the only other utility to have had a comprehensive review of CAV programs in a GRC. Therefore, a major portion of CEC's recommendation in this case relates to a reclassification of PG&E's CAV programs as follows: technology development to be handled in RD&D; market research infrastructure assessment and systems impacts to be handled in DSM measurement and evaluation; and NGV and EV promotion to be handled in DSM load building.

DRA had a slightly different concern regarding the classification of the CAV program. DRA's concern really focuses on the fact that many issues need to be addressed in the Commission's ongoing proceeding to develop a policy governing utility involvement in the market for low emission vehicles (LEVs). DRA is concerned that until issues are resolved in this LEV proceeding, it is unwise to treat utility involvement in CAV programs as automatic utility services and therefore to embed funding in general rate cases. (Exhibit 145.)

In its reply brief, PG&E stated in response to CEC's concerns that in comments filed in the DSM OIR, 91-08-003, on August 3, 1992, both DRA and PG&E have recommended a new separate category for alternate fuel vehicles within the DSM funding and reporting classifications. In addition, PG&E submits that at this time incorporation of CAV programs within DSM and other reporting areas is not required. PG&E believes that reviewing and approving CAV programs in the manner presented by PG&E in this case makes it easier for the Commission and other parties to review the whole package and increases the likelihood that funding requests will be coordinated and efficient, and will result in more effective total effort.

We admit that PG&E was somewhat caught between timing issues in several ongoing Commission proceedings. Therefore we do not chastise PG&E for presenting its CAV program in the manner it did in this GRC. We will allow for guidance in both the DSM and LEV proceedings as to the appropriate way for PG&E to address its CAV programs in future GRCs.

<u>19.3 Level of CAV Program Funding</u>

DRA sets forth in its Exhibit 156 a comparison of its funding levels recommended for CAV to PG&E's funding levels. Generally, CEC recommended funding levels between PG&E and DRA proposals.

In the Comparison Exhibit (Exhibit 235), PG&E's updated expense request for CAV is $9.940 million, $3.116 million for Electric, $6.824 million for Gas. DRA's recommended funding level is $2.226 million overall, $.578 million for Electric and $1.648 million for Gas.

The major areas of difference between PG&E and DRA are the internal PG&E fleet use of electric vehicles and the need for external clean air vehicle marketing and industry support activities.

In reaching its much lower estimates, DRA relied heavily on D.91-07-018, where the Commission authorized PG&E to spend some $12.4 million plus interest to implement a pilot natural gas vehicle program. In issuing this decision, the Commission ordered PG&E to terminate its pilot program two years from the decision date, which would be July 2, 1993, unless further modified by the Commission. Furthermore, the Commission ordered that no additional funding would be granted until the completion of the two-year program, and its subsequent review by the Commission.

Overall, DRA believes it is inappropriate and premature for PG&E to request GRC funding which will transform their pilot NGV program into a normal GRC-funded operation. This concerns DRA because it is not clear that the Commission's development of a long-term policy will necessarily mean that utilities will be allowed a presence in the market for LEVs or CAVs. DRA believes it is appropriate to not enlarge this program prior to the Commission being allowed to develop a long-term policy in a more appropriate forum of the LEV proceeding. (I.91-10-029.)

This is not to imply that DRA wishes to disallow all of PG&E's current GRC funding requests. DRA believes that PG&E's internal NGV program or its fleet program and its own stations are reasonable activities and should be funded. The CEC has no specific dollar recommendation for this area.

We are concerned that the level of funding be consistent between the expiration of the natural gas vehicle pilot program and our pending decision in I.91-10-029. We will treat this issue as we did in our recent GRC decision for SDG&E (D.92-12-019). Therefore, we authorize continued funding at current annual levels pending our order in I.91-10-029. PG&E is authorized to continue the balancing account treatment pursuant to D.91-07-018 between the expiration date of the account and a decision in I.91-10-029.

However, as to PG&E's request to incorporate 65 electric vehicles into its own fleet, DRA had major concerns. DRA recommended that only one vehicle per year be added, a total of three vehicles over the rate case cycle. DRA argues that while it was willing to allow PG&E to convert 800 of its vehicles to natural gas, the electric car market is much less farther along. DRA believes purchase and evaluation of three electric vehicles is an adequate number given their expense and the fledgling nature of the technology. (RT 26:2188-2190.) DRA argues that PG&E has failed in an affirmative showing that the cost of 65 electric vehicles, for which it seeks ratepayer reimbursement, is reasonable given the high cost and limited usefulness of electric vehicles. Of course, DRA also points out that this is a major investment to make when so many policy issues in this area are still pending before the Commission. PG&E counters that it believes that 65 vehicles over three years are fully supported by the record and should be approved.

The second area where PG&E and DRA had disagreement was to what DRA called external activities or those activities that do not relate directly to PG&E's own fleet. DRA in this area recommended no funding at all while PG&E requested $7.7 million, broken down into $2.5 million for Electric and $5.2 million for Gas. Once again the CEC recommendations are difficult to state in exactly equivalent terms but are approximately $3.5 million total. DRA cites the pendency of the investigation in this area as a reason to remove all funding that does not relate directly to PG&E's own fleet. DRA believes it is imprudent to prejudge the forum where these policy decisions are more appropriately determined. PG&E counters that if the Commission's long-term policy in the investigation is to support continued or expanded programs, then the funding levels for programs requested by PG&E in this proceeding are appropriate. Further, PG&E argues that continuity of funding is important because funding gaps can be disastrous to programs.

Particularly as to electric vehicles, we believe it is critical for this Commission to continue to show support and leadership in this area. Therefore, we will authorize more dollars than DRA recommends but less than PG&E's full request. In addition, we will alter the regulatory treatment proposed for electric vehicle purchases.

We agree with PG&E's reasons for placing electric vehicles within its own vehicle fleet. We agree that the procurement of electric vehicles provides meaningful support for a new and promising technology. We also believe that PG&E conveys a message of corporate responsibility by evaluating the performance of electric vehicle technology to reduce emissions within its own vehicle fleet. However, we view these initial fleet placements as demonstrations to assess the degree to which performance characteristics of electric vehicles can serve the needs of the utility. We believe that the unproven usefulness of electric vehicles, coupled with their high cost, render these purchases as unreasonable additions to common plant on which the utility can earn its rate of return. Instead, we authorize PG&E to establish an electric vehicle tracking account and to record the total cost of electric vehicle purchases and related expenses as expense items in this account.

Second, we authorize PG&E to spend no more than $1.8 million ($1990) annually on electric vehicle purchases and related expenses which will be recorded in the electric vehicle tracking account. These activities would include the total cost of electric vehicle procurement, support/administrative activities related to the electric vehicle purchases, and $.067 million ($1990) in expenses as requested by PG&E for participation in electric vehicle trade associations. We do not intend to further micro-manage the utility in how it chooses to allocate the authorized funds among areas that relate directly to its own fleet. Any funds which have not been spent in these areas prior to our pending decision in I.91-10-029 shall be returned to ratepayers, and subsequent utility involvement in electric vehicle activities shall conform to the policies we develop there.

Finally, we appreciate the CEC's input and concern in this area. We welcome its continued input in our LEV investigation.

## 20. Demand-Side Management

### 20.1 Overview

We are pleased that the area of demand-side management was not the painful process that we went through in Edison's last GRC decision. We are pleased that the parties followed our overall directives that this was to be a forum for funding issues rather than overall policy issues for DSM. We are progressing with our overall policy for DSM issues in our ongoing Rulemaking 91-08-003 which accompanies I.91-08-002.

Further, the issue was streamlined in this case by a Joint Recommendation on most issues being submitted by DRA, PG&E, CMA, CLECA, and the California State Department of General Services (DGS). The one issue that was not resolved by the joint recommenders related to the appropriate funding level for thermal energy storage load management program. In addition, other parties who did not join in the Joint Recommendation raised certain concerns during hearing. All parties were allowed to cross-examine the proponents of the Joint Recommendation as much as they requested.

We are pleased to say that there is no party who believes the Joint Recommendation is outrageous. Rather, the following parties had concerns on fairly specific areas. The Coalition for Energy Efficiency and Renewable Technologies (CEERT), together with the Natural Resources Defense Council (NRDC), generally support the Joint Recommendation but recommend that there be a restored funding for 30 megawatts of conservation acquisitions. This 30 megawatts comes from the Commission's decision in D.92-03-038 to reduce the size of PG&E's DSM bidding pilot project from 50 megawatts to 20 megawatts. While we appreciate that these two parties in particular were probably displeased with our decision to downsize the pilot bidding program, we have no wish to revisit or alter that decision in this proceeding.

The CEC also generally supports the Joint Recommendation of the parties but has concerns regarding how shareholder incentives were developed. Finally, TURN generally supports the Joint Recommendation also but wishes to see changes in the refrigerator rebate program, full compliance with energy efficiency building standards (Title 24) as a condition for participation in the new construction program, a prohibition from spending any further money on the Delta project until clear results have been obtained, and a lowering of the shareholder incentives, the opposite of CEC's concern. CMA shares TURN's concerns regarding Title 24 compliance.

We will address all of these issues in further detail in the sections to follow. We note at the outset that it is not our desire to create an absolutely perfect DSM system in this GRC, but rather to have something reasonable in place as we continue to resolve generic DSM issues in our policy proceeding previously referred to.

## 20.2 The Joint Recommendation

PG&E and DRA, the major movers behind the Joint Recommendation, represent that there were extensive negotiations among all active parties in this phase of proceeding. That this is true is indicated by not only the signers of the Joint Recommendation but the overall general support by other parties to this proceeding. With the few exceptions, virtually all parties support the program funding levels arrived at in the Joint Recommendation. We will include in the text of this decision the Table 2 attached to the Joint Recommendation that indicates the funding levels requested by PG&E, then those recommended by DRA, and finally the compromises reached under the Joint Recommendation.

# Table 2
## 1993 DSM Program
## Funding Level (1990 $ Million)[2]

| Program | PG&E Requested | DRA Recommended | Joint Recommendation |
|---|---|---|---|
| Conservation/Energy Efficiency | | | |
| Information | | | |
| Residential | 3.6 | 3.6 | 3.6 |
| Nonresidential | 3.0 | 3.0 | 3.0 |
| EM Services | | | |
| Residential | 19.5 | 17.0 | 17.0 |
| Commercial | 8.6 | 7.6 | 8.6 |
| Industrial | 2.7 | 2.7 | 2.7 |
| Agricultural | 2.8 | 2.8 | 2.8 |
| Direct Assistance | 35.6 | 35.6 | 35.6 |
| New Construction | | | |
| Residential | 34.2 | 33.2 | 34.2 |
| Nonresidential | 23.1 | 23.1 | 23.1 |
| Retrofit Energy Efficiency Incentives | | | |
| Residential Weatherization | 6.5 | 5.0 | 5.0 |
| Residential Appliance Efficiency | 24.1 | 9.4 | 22.0 |
| Commercial EM Incentives | 26.2 | 17.8 | 25.0 |
| Industrial EM Incentives | 7.4 | 5.2 | 7.0 |
| Agricultural EM Incentives | 7.5 | 1.3 | 7.0 |
| Other DSM (Bidding) | 14.0 | 14.0 | 5.7[3] |
| Other | | | |
| Residential | 9.6 | 9.6 | 9.6 |
| Nonresidential | 3.1 | 1.0 | 1.0 |
| **Total Conservation/Energy Efficiency** | **231.5** | **191.9** | **212.9** |
| Load Management[4] | | | |
| Res. A/C Cycling | 0.8 | 0.8 | 0.8 |
| Interruptible/Curtailable | 1.2 | 1.2 | 1.2 |
| Group Load Curtailment | 0.4 | 0.4 | 0.4 |
| Time-of-Use (Res., Nonres., Mandatory) | 15.6 | 15.6 | 15.6 |
| Real Time Pricing | 0.4 | 0.4 | 0.4 |
| Demand Control Center | 0.1 | 0.1 | 0.1 |
| Swimming Pool Pump | 1.5 | 1.5 | 1.5 |
| **Total Load Management** | **20.0** | **20.0** | **20.0** |
| Fuel Substitution | 1.2 | 1.2 | 1.2 |
| Load Retention | 5.1 | 2.5 | 2.5 |
| Load Building | 3.9 | 0.0 | 0.0 |
| Measurement & Evaluation | 27.0 | 27.0 | 27.5 |
| **Total DSM** | **288.6** | **242.6** | **264.1** |

2 The Parties agree that all program expenses, including customer rebates, should be escalated to 1993 dollars for the test year, and 1994 and 1995 dollars respectively, for the two subsequent years.

3 This amount was authorized in DSM Bidding Decision No. 92-03-038.

4 Does not include the Thermal Energy Storage Program.

The parties represent that the Joint Recommendation is a reasonable and fair compromise and further satisfies the interests of the Commission, DRA, and PG&E. The parties note that the Joint Recommendation provides for the continued expansion of PG&E's energy efficiency programs. The parties agreed to an increase of approximately $66 million, or 45% above PG&E's 1992 authorized budget levels, for energy efficiency programs. Programs that have shown particular success have been expanded even more rapidly. For example, PG&E's nonresidential new construction program is increased by 379% and the agricultural energy efficiency incentives (EEI) program is expanded by 538%. In addition, the Joint Recommendation also gives PG&E spending flexibility to increase funding for its retrofit energy efficiency programs by up to 30%, which equals $21.5 million per year above the "authorized levels." The Joint Recommendation provides that PG&E be authorized to increase its budget ceilings to 130% of authorized spending levels only if certain advice letters are filed with the Commission.

The Joint Recommendation also permits PG&E to borrow funds from future years for current DSM expenses or to carry over unused funds in one year into subsequent years. As demonstrated in Table 3 PG&E is allowed to shift funds and/or exceed authorized budgets, as long as the established minimum performance standards, when applicable, are met for each individual program. This gives PG&E a large amount of flexibility to respond to fluctuations in demand for its various programs.

**Table 3**
**Joint Recommendation for Spending Flexibility and Cap**
**Discretionary Movement of Funds and Spending Cap**

| | Carry-Over Carry-Forward | Between Prgms, Within Category | In/Out of Category, Subcategory[5] | Spending Cap |
|---|---|---|---|---|
| I. SHARED SAVINGS | | | | |
| Res. AEI | Yes | Yes | NA | NA |
| Res. WRI | Yes | Yes | NA | NA |
| Comm. EEI | Yes | Yes | NA | NA |
| Ind. EEI | Yes | Yes | NA | NA |
| Agric. EEI | Yes | Yes | NA | NA |
| DSM Bidding | Yes | Yes[6] | NA | NA |
| Total Shared Savings | Yes | Yes | No[7] | 130%[8] |
| II. PERFORMANCE ADDER | | | | |
| A. New Construction | | | | |
| Res. NC | Yes | Yes | NA | NA |
| Nonres. NC | Yes | Yes | NA | NA |
| NC Subtotal | Yes | Yes | No[7] | 100% |
| B. EM Services | | | | |
| Res. EM Services | Yes | Yes | NA | NA |
| Comm. EM Services | Yes | Yes | NA | NA |
| Ind. Em Services | Yes | Yes | NA | NA |
| Agr. EM Services | Yes | Yes | NA | NA |
| EM Services Subtotal | Yes | Yes | Yes | 100% |
| C. Direct Assistance (Non-mandatory) | Yes | NA | Yes | 100% |
| Total Performance Adder | NA | NA | No[7] | 100% |
| III. EXPENSE-ONLY | | | | |
| A. Direct Assistance (Mand.) | Yes | NA | No | 100% |
| B. Information | | | | |
| Residential | Yes | Yes | NA | NA |
| Nonresidential | Yes | Yes | NA | NA |
| Information Subtotal | Yes | Yes | No | 100% |
| C. Load Management | | | | |
| Res. A/C Cycling | Yes | Yes | NA | NA |
| Pool Timer/Tripper | Yes | Yes | NA | NA |
| Interr./Curtailable | Yes | Yes | NA | NA |
| Load Management Subtotal | Yes | Yes | No | 100% |
| D. Fuel Substitution | Yes | Yes | No | 100% |
| E. Load Retention | Yes | Yes | No | 100% |
| F. Measurement & Evaluation | Yes | Yes | No | 100% |
| Total Expense-Only | Yes | Yes | No | 100% |

[5] Subcategory applies only to Performance Adder and Expense-Only categories.

[6] Funds can be transferred from other shared savings programs to DSM Bidding, but not from DSM Bidding to other Shared Savings programs.

[7] An exception for shifting funds between Shared Savings and Performance Adder programs will be permitted for 1995 programs. The maximum amount shifted will be $10 million and will be based on an advice letter filing by PG&E filed no later than March 1, 1994.

[8] The spending cap applies to the total of all Shared Savings programs, and not to the individual programs; this spending cap is subject to the conditions described in Section 4b.6.

While it is tempting to look at the Joint Recommendation as perhaps a "split the baby" approach, the parties made it clear that this was not how the numbers were arrived at. (RT 51:4745-4747.) To explain further, the Joint Recommendation differs from DRA's original recommendation primarily by $21 million of increased funding for energy efficiency programs. But on the other hand, PG&E agreed to reduce its load retention budget by 50%, and eliminated its load building programs entirely. These were two areas which DRA strongly advocated budget cuts.

The Joint Recommendation also addressed the issue of shareholder incentives. This is an issue that has taken up much Commission attention in the last few years related to the DSM programs. Joint Recommendation proponents correctly point out that this GRC is being considered in the middle of a transition period of Commission policy on shareholder incentives. We discussed the issue at length in Edison's last GRC decision (D.91-12-076). In addition, the issue has been addressed in D.92-02-075, in the DSM policy proceeding, where we set forth an interim opinion on target shareholder earning levels for DSM programs. DRA and PG&E, along with the other signers of the Joint Recommendation, believe that they have complied with the interim policy in their Joint Recommendation. The parties emphasized and we concur that the shareholder incentives adopted in the Joint Recommendation are again interim in nature. This interim nature should be kept in mind as we later discuss the various recommended adjustments or alterations to the Joint Recommendation. The parties correctly point out that the issue of shareholder incentives will be revisited soon in another proceeding and that the decision in that proceeding could supersede any finding here. Therefore, we will not go into as detailed a discussion as the parties have in their briefs and testimony on this issue.

Overall, we find the Joint Recommendation (Exhibit 214) to be a thorough document and we commend the parties for the clearly arduous effort that went into reaching agreement on these issues. We will only briefly highlight the other aspects of the Joint Recommendation. The Joint Recommendation includes PG&E's agreement to change program design and implementation procedure to further ensure that its various programs will be cost-effective for ratepayers. In addition, PG&E has agreed to provide additional analysis of its CEE programs by specified deadlines and commits to a schedule for the release of its measurement and evaluation studies. In addition, the Joint Recommendation sets up a reallocation of PG&E's proposed budget of targeted transmission and distribution, also known as the son of the Delta project. PG&E agrees to complete and distribute an evaluation study of its existing Delta program by June 1, 1994.

Finally, the Joint Recommendation's resolution of the issue of spending flexibility, which is always a thorny issue in DSM programs, represents a compromise between DRA's and PG&E's positions. With respect to shared savings programs, PG&E is allowed to expand its programs by up to 30% above authorized levels and to shift funds between shared savings programs. PG&E would be permitted to make both of these changes without seeking additional Commission authorization. However, in the negotiations particular attention was paid to PG&E's flexibility regarding new construction programs. Under the Joint Recommendation, these programs are given "performance adder" incentive treatment rather than "shared savings treatment." Accordingly, the 30% spending flexibility available for PG&E's retrofit programs is not applicable to the new construction programs. Instead, due to the recent slump in new construction starts and the possibility of a rebound during this GRC cycle, DRA agreed first, to a 93% increase in the new construction program budget, and second, to grant PG&E flexibility to shift $10 million of funds from shared savings programs to new construction programs.

We adopt the Joint Recommendation in total. We will briefly address the alterations to the Joint Recommendation proposed by various parties.

20.2.1 NRDC's & CEERT's Proposals

NRDC's and CEERT's recommendations can generally be characterized as attempts to supplement the settlement reached by the Joint Recommendation. NRDC argues that the increases over the 1992 budget are not quite as dramatic as DRA suggests. NRDC is troubled by the loss of the 30% flexibility increase for all of the new construction programs. NRDC is generally in favor of additional spending flexibility for new construction programs. NRDC argues that providing additional flexibility does not mandate dollars be spent. If the program budget caps have been set high enough to meet system needs, then the additional spending authority would not be exercised.

Additionally, NRDC and CEERT both wish to restore funding for 30 megawatts of conservation acquisitions. As we have already stated, this issue arises from our decision to reduce PG&E's DSM pilot bidding project in D.92-03-038. NRDC and CEERT contend that since PG&E's original resource plan and budget included 30 megawatts of cost-effective savings that cannot now be acquired from the pilot bid, it should be acquired instead through the utility's own programs. NRDC conclude that otherwise PG&E would have to substitute more expensive generation for the lost megawatts. NRDC and CEERT do concede that the question of whether the 30 megawatts and associated funding should be restored is separate from that of whether private firms should participate in securing these savings. NRDC acknowledges that DRA is correct in noting that the Commission has never found that PG&E needed 50 megawatts (the original proposal) of PG&E's sponsored energy service company (ESCO) activity during this rate case cycle. NRDC and CEERT argue that we have an ample record to support that conclusion in this case.

We disagree with NRDC on budgetary flexibility being increased and with CEERT and NRDC as to the 30 megawatts of conservation acquisitions. As we have stated in prior proceedings, we will adopt settlements only if there is a showing that they are not contrary to the public interest.

> "If our goal truly is 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 weary of our settlement process if we alter settlements as a matter of course. Substituting our judgment for that of the parties is only appropriate if the public interest is in jeopardy." (D.91-05-029.)

While NRDC and CEERT disagree with the Joint Recommendation, we find their arguments do not question that the joint settlement is in the overall public interest given the status of DSM issues here at the Commission. We encourage both NRDC and CEERT to continue to participate in our policy-setting proceedings regarding DSM issues.

### 20.2.2 CEC's Proposals

The CEC opposes the Joint Recommendation shared savings mechanism because in its opinion the mechanism has no economic or policy rationale, is unduly complex, and will discourage superior performance and achievement of the state's policy of obtaining all cost-effective DSM savings. The CEC is alone in its criticism of this aspect of the settlement, suggesting that PG&E will earn too little money.

The CEC attempts to separate PG&E from the Joint Recommendation. However, PG&E has always stated that in the policy proceeding, R.91-08-003, PG&E intends to argue for higher levels of shareholder incentives than have been reached in the Joint Recommendation. The parties reached a compromise knowing that what was decided in this GRC is only temporary in nature. We appreciate the fact that the parties chose not to spend an undue amount of time litigating an issue that is more appropriately to be litigated in the DSM proceeding.

We believe that the shared incentive mechanism as agreed to in the Joint Recommendation is fair, reasonable, and is in the best interest of PG&E's ratepayers. It must be borne in mind that PG&E's ratepayers are paying for all of PG&E's DSM programs at this time. Given the generous increases which the Joint Recommendation allows, we believe that we are in fact following the state's policy of encouraging cost-effective DSM savings.

As PG&E's witness in this area put it:

> ". . . The bottom line is that at the end of the day we felt that the stipulated package...in total served the interests of the company and offered us the type of incentive and program funding that we feel would be adequate to meet our resource plan objectives." (RT 48:4521.)

In this regard, we believe PG&E is well able to look after its own interests. We reject the CEC's criticism of the shared incentives program for this GRC. As we have already encouraged the NRDC and CEERT, we welcome the CEC's participation in our ongoing policy-making DSM proceeding.

<u>20.2.3 TURN's Proposals</u>

TURN enumerates four concerns that it has regarding the joint recommendation. First, TURN recommends that there be changes to the refrigerator rebate program in order to discourage the purchase of large refrigerators. TURN advocates a cap on the unit size of refrigerators that are eligible for the PG&E rebate program. TURN points out that larger units use more energy, and units with additional features (such as ice through the door) consume more than units of the same size which lack such features, even among the more efficient models qualifying for PG&E's rebate. TURN's argument is that if the refrigerator rebate program is to achieve the greatest amount of energy savings, it should recognize the additional efficiency benefits from smaller, less feature-laden models and be structured accordingly.

PG&E argues that TURN's proposal is a throwback to the days when conservation was the theme of DSM, and people were supposed to get by with less, by giving up creature comforts. PG&E points out that one of the themes arising out of the California Collaborative that was the precursor to our DSM proceeding is that people don't have to suffer to be energy efficient. PG&E states that many people, due to family size, lifestyle, or personal preference, choose to buy larger refrigerators, or refrigerators with features such as water or ice through the door.

PG&E argues that manufacturers are going to produce both large and small refrigerators to meet customer demand. PG&E believes that in the absence of its rebate on refrigerators in the larger category (over 20 cubic feet), there would be very few large refrigerators in the market that exceed the minimum federal energy efficiency standards. PG&E believes that significant lost opportunities in PG&E efficiency would result from TURN's suggestion because many people would continue to buy these large and/or featured refrigerators based on personal choice.

PG&E believes TURN's recommendation in this area is a misguided regulatory attempt to tell consumers what they should be buying. PG&E points out that one of the strengths of the energy efficiency programs is that they work with the market to produce and sell energy-efficient products that both meet consumer needs and use less energy than the standard product.

We concur with PG&E that it would be inappropriate for us to limit the refrigerator rebate as it has been designed.

TURN's second proposed change to the Joint Recommendation is based on TURN's serious concern about the failure of members of California's construction industry to comply fully with the building standards set forth in Title 24 (Energy Efficiency

Standards). TURN proposes limiting participation in PG&E's new construction rebate program to those contractors whose structures fully comply with Title 24.

TURN objects to PG&E using ratepayer money to reward builders whose buildings may not need all the basic Title 24 requirements. Secondly, if PG&E-rebated equipment is being installed in a home not fully complying with Title 24, the measured gains in efficiency achieved by such equipment may be inflated. TURN points out that PG&E's new construction programs are intended to achieve benefits beyond those statutorily mandated by Title 24 in California. TURN's solution to this problem is for the Commission to direct PG&E not to provide rebates to any builder unless the entire structure (beyond the program areas) complies with Title 24, as verified by an onsite inspection conducted by PG&E of a representative sample of the buildings for which it is providing rebates. TURN recommends that a building with features funded by PG&E must comply with Title 24 standards not only at the time the plans are submitted, but also when construction is complete.

TURN concludes that by requiring Title 24 compliance, the Commission will ensure that the energy efficiency measures funded by ratepayers actually achieve energy savings above and beyond those attained under Title 24.

TURN goes on to state that any builder who wishes to receive the incentives under PG&E's program will have to submit the entire building to scrutiny. Conversely, those builders who will not allow full inspection will not be eligible for this program.

No other party in the proceeding supports TURN's recommendation.

PG&E raises the concern that this kind of additional requirement will discourage builder participation in PG&E's program. In addition, the issue of PG&E's jurisdiction to inspect and potentially second-guess the conclusions of local building departments has not been sufficiently answered by TURN. (RT 49:4569-4573) PG&E recommends that this issue continue to be worked on with its advisory committee on this overall program. PG&E points out that TURN found out about this issue through its participation in advisory committee meetings.

We agree with PG&E that this is an issue not yet ready for any Commission action. We encourage PG&E to continue to address this issue in its advisory committee study. We have no desire at this time to make PG&E an unofficial building inspection department. The goal of the new construction program is to encourage builders to participate, not to burden them with additional layers of bureaucracy.

TURN's third proposal is a rejection of any allowance for targeted transmission and distribution projects until the results from the Delta project have been evaluated. TURN points out that PG&E's initial funding request sought $6 million for its targeted transmission and distribution (TT&D) program. This program's purpose is to defer transmission and distribution additions by focusing the application of DSM programs upon a specific geographic area. Thus far, the only such program in operation is commonly referred to as the "Delta project." TURN acknowledges that the Joint Recommendation does not have a separate allocation for the TT&D program. Instead, a reduced amount of $3.5 million was redistributed among the other DSM programs. However TURN states that although the funds would no longer be specifically designated for TT&D, nothing in the Joint Recommendation would prevent PG&E from taking these funds from each individual program and targeting a specific area, just as if the funds had been allocated for that express purpose. Therefore, TURN wishes the $3.5 million which was reallocated from TT&D program to be stricken from PG&E's overall DSM budget. We note that TURN relies on the testimony of CLECA extensively in its brief; however, CLECA is one of the signatories to the Joint Recommendation.

PG&E responds by stating that the TT&D language is in the Joint Recommendation simply to express PG&E's intention to spend resource dollars on a TT&D project. PG&E does want the ability to spend $3.5 million on a "son of Delta" project, but will pursue further projects only in 1994 or 1995, after evaluation of the Delta project, and after consultation with the advisory committee, in accordance with the concerns of CLECA and TURN. (RT 51:4733.) PG&E points out that if, after consultation with the committee, the money is not spent, and if it is not spent on resource programs, the money will be returned to ratepayers, in accordance with normal balancing-account procedures.

We believe the issue of further funding for TT&D programs has been adequately addressed by the Joint Recommendation. Nothing that TURN has raised convinces us that we should alter that agreement reached by many parties in the proceeding.

On the issue of shareholder incentives, TURN feels differently than the CEC. TURN believes that the Joint Recommendation, which proposed that shareholder earnings be calculated as the product of the authorized rate of return and the forecast of annual utility program costs, is too generous. TURN believes that the rate of return used in calculating the shareholder incentives for DSM programs ought to be significantly lower than the rate of return earned on utility-constructed plants. TURN believes this is self-evident from one basic distinction between the two types of investments: Shareholder funds are not at risk in the DSM programs. The money expended on these programs comes exclusively from ratepayers.

We had thought that it had been made clear in our DSM proceeding at the issue of shareholder incentive would be addressed in that proceeding. The Joint Recommendation is adopting a program for only an interim period, which will be changed depending on what is the outcome of our policy-making DSM proceeding. Therefore, as we did with CEC's concerns, we will reject TURN's suggestions for purposes of this GRC and adopt the shareholder incentives set forth in the Joint Recommendation until a further order by the Commission in the DSM proceeding.

Finally, TURN raised several issues regarding consistency between DSM programs and other areas of PG&E's operations. We will not go into them at length here; we note that they are more appropriately addressed in either our Phase 2 rate design phase of this case or in the DSM proceeding.

Overall, objections raised by TURN do not compel us to alter or modify that Joint Recommendation. Despite the comments of the few parties who raised concerns regarding certain aspects of the Joint Recommendation, we find it to be reasonable and in the public interest. This is particularly true in light of the fact that it is a temporary device and policy issues will be ultimately determined in the DSM policy proceeding. We encourage the parties who raised concerns in this proceeding to continue to participate in the policy-making proceeding on these issues. Certainly for purposes of this GRC, the Joint Recommendation balances well the interests of PG&E's ratepayers, stockholders, and other interested parties to our proceedings. Further, it does comport with our statutory requirements as set forth in the Code.

### 20.2.4 Thermal Energy Storage

The one area where PG&E and DRA were unable to reach agreement regarding DSM issues relates to PG&E's thermal energy storage (TES) program. Thermal energy storage systems make chilled water or ice during off-peak periods to meet cooling load during peak periods. As such, they are promoted as a load management program. Thermal energy storage systems has been an ongoing program for many years. (RT 49:4586.) During the hours of greatest air conditioning load, the chilled water or ice reduces the size of the air conditioning unit needed for the building, thus reducing electrical demand. In a time of relatively high reserve margins for PG&E, this capacity would have a reduced value.

DRA recommends that PG&E's thermal energy storage program be funded at $1.6 million per year. This is the same level of funding as was approved by the Commission in PG&E's last GRC decision. (34 CPUC2d 199, 408, 412 (1989).) The CEC joined DRA in this recommendation.

PG&E, on the other hand, recommends funding of $6 million for 1993, a four-fold increase.

DRA acknowledges that the Commission recently gave PG&E an amount of additional funding for its TES program in a recent ECAC decision. (D.91-12-015, mimeo., page 49.) There, $2.5 million was authorized for 1992 TES program. PG&E argues that given what happened in the last ECAC proceeding, the budget should be over $4 million. DRA responds that the ECAC decision should not form an adequate basis for a three-year expansion of this program. DRA contends that the issue was not the subject of much scrutiny in the ECAC proceeding. In fact, DRA points out that the decision only has one sentence of discussion of PG&E's proposed funding level. DRA argues that the record is much more substantial in this GRC proceeding and fails to support the expansion of this program.

DRA believes the Commission should treat thermal energy storage as a "resource program." Then TES would be subject to the same scrutiny as other resource programs that is rigorous measurement and resource plan linkages through Integrated Cost Effectiveness Methodology (ICEM) analyses. DRA points out that such a demonstration has not been made by PG&E for this program.

In addition, both DRA and CEC point out that PG&E's own analysis of this program shows it to be only marginally cost-effective with the benefit/cost ratio of only 1.08:1. Therefore while DRA acknowledges that this program may have some merit and deserves further study, the increase sought by PG&E is inappropriate at this time.

Finally, PG&E raises the point that if TES is not pursued now in new construction or major remodeling projects, it becomes a "lost opportunity" that can never be pursued. Therefore, PG&E contends that now is the time to increase the TES program from the level approved in the last ECAC decision to the $6 million level sought in this GRC.

We are more persuaded by the testimony of DRA's and CEC's witnesses on this issue. An increase granted in an ECAC proceeding does not preclude us from doing a more formal analysis in a GRC. In fact, it is in the GRC where these programs obtain the scrutiny that they deserve. We concur with the arguments raised by CEC and DRA on this issue and will adopt a funding level for 1993 of $1.6 million.

20.2.5 Conservation Voltage Reduction

This issue was injected into the proceeding by Mr. Sesto Lucchi requesting that PG&E continue its conservation voltage reduction (CVR) program. Mr. Lucchi is a former Commission employee. However, PG&E has been filing reports to the Commission regarding CVR, indicating that beyond current maintenance it is not cost-effective and will remain noncost-effective until marginal costs rise significantly. In fact, PG&E points out that the Commission staff currently is no longer interested in even receiving reports about CVR (Exhibit 99). Mr. Lucchi point to no studies of cost-effectiveness nor did he know the cost of the proposal he is making. In its brief PG&E says that it will continue its current CVR maintenance activities. PG&E points out that it will reevaluate the program and reinstitute it when and if it becomes cost-effective in the future. But PG&E does not have any desire to continue to generate reports for CACD that no current employees of the Commission have an interest in reviewing.

We concur with PG&E that there is no reason at this time to continue the reporting requirements which we set up some time ago for CVR. Likewise, Mr. Lucchi's recommendations are not backed up by facts to justify us to take any further action in this area at this time. While Mr. Lucchi's history of the program was of some interest, it has added nothing of substantive value to this proceeding.

## 21. The Geysers 15 Retirement

### 21.1 Overview

PG&E and DRA disagree on several issues surrounding the Geysers 15 power plant. The Geysers Unit 15 was retired on December 29, 1989. PG&E proposes to recover, through the ECAC balancing account, its prudently incurred steam costs for the operation of Unit 15, including the $5,028,865 in steam payments for which recovery was deferred pending reasonableness hearings. PG&E also proposes to accord Unit 15 normal retirement status with no explicit adjustments to rates.

DRA disagrees and believes PG&E should not recover the deferred steam costs. In addition, DRA believes PG&E should refund over a five-year period, with interest, $36 million that will have been accrued in a memorandum account for depreciation, return, and net O&M expenses for assumed costs allocable to Unit 15 during the period February 23, 1990 through December 31, 1992.

In addition, PG&E and DRA have a major disagreement over rate base treatment of this plant. DRA believes that PG&E should reduce the overall Geysers plant rate base by $30.2 million and the Commission should allow PG&E to recover that amount over a five-year period, without interest. DRA believes it inappropriate to pay a return on Geysers 15 because it is no longer used and useful. DRA believes its proposed ratemaking treatment fairly balances costs and risks between utility shareholders and ratepayers. DRA further contends that its recommendation is squarely in line with Commission precedent.

A brief history of electric generation at The Geysers since the 1950s may be in order. During the 1960s and 1970s, the development and operation of PG&E's geothermal power plants became a highly successful venture, both economically and technically. The Geysers developed into the largest geothermal installation in the world. Located in Northern California, The Geysers was viewed as a clean, environmentally preferred resource and was actively encouraged at virtually all levels of government from the CEC, the State Legislature, our own Commission, and the Federal Government.

The unit in question here, Geysers Unit 15 was actually PG&E's 13th Geysers plant, achieving commercial operation in 1979. Unit 15 was the first in an area that had not previously been developed but at the time showed every promise of being as reliable and consistent as the then-developed portions of The Geysers. Unfortunately, almost from the start of operation, there were problems with the quality and quantity of steam available to Unit 15. PG&E made numerous efforts to rectify the situation, making physical improvements to the plant, and working with the steam supplier. Later, efforts were made to sell the plant.

These efforts did not work out. When PG&E enforced an offset provision in the steam purchase contract and ceased payments for steam, the steam supplier cut off steam to Unit 15 on April 7, 1989, thereby idling the plant. Thus, the retirement occurred on December 29, 1989. DRA does not dispute this chronology of Geysers 15 history. What is in dispute is the appropriate rate-making treatment of this plant given its current circumstances.

PU § 55.5 is relevant to the determination of the Geysers Unit 15:

> "455.5. (a) In establishing rates for any electrical...corporation, the commission may eliminate consideration of the value of any portion of any electric...generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility. Upon eliminating consideration of any portion of a facility or disallowing any expenses related thereto under this section, the commission shall reduce the rates of the corporation accordingly and shall, for accounting purposes, record the value of that portion of the facility in a deferred debit

account and shall treat this amount similar to the treatment of the allowance for funds used during construction. When that portion of the facility is returned to useful service, as provided in subdivision (c), the corporation may apply to the commission for the inclusion of its value and expenses related to its operation for purposes of the establishment of the corporation's rates.

"(b) Every electrical...corporation shall periodically, as required by the commission, report to the commission on the status of any portion of any electric...generation or production facility which is out of service and shall immediately notify the commission when any portion of the facility has been out of service for nine consecutive months.

"(c) Within 45 days of receiving the notification specified in subdivision (b), the commission shall institute an investigation to determine whether to reduce the rates of the corporation to reflect the portion of the electric...generation or production facility which is out of service. For purposes of this subdivision, out-of-service periods shall not include planned outages of predetermined duration scheduled in advance.

"The commission's order shall require that rates associated with that facility are subject to refund from the date the order instituting the investigation was issued. The commission shall consolidate the hearing on the investigation with the next general rate proceeding instituted for the corporation."

In compliance with that section, PG&E notified the Commission after Geysers Unit 15 had been shut down for nine months. The Commission responded by issuing I.90-02-043 on February 23, 1990, and the investigation was properly consolidated with this general rate case proceeding in accordance with the above code section.

<u>21.2 Appropriate Rate Base Treatment</u>

The parties' disagreement over the appropriate rate base treatment for the Geysers Unit 15 is fundamental. PG&E believes that because the Geysers plants are for accounting reasons treated via group depreciation, there is no need to remove from rate base any dollar amount that relates to Geysers 15 plant alone. PG&E points out that like most other utilities in the country and in conformance with CPUC Standard Practice U-4, PG&E groups similar items of plant and equipment together and depreciates the group over a single, composite average life, due to the belief that an estimate of the group average life will generally be more accurate than an estimate of the expected life of any individual element. The use of a composite life assumes that not all items in the group will live exactly the expected average for the group; some items will have a shorter-than-average life, while others will experience longer-than-average lives. Under group depreciation, according to PG&E, an asset is considered fully depreciated at the time of its retirement. (Exhibit 221.) Therefore, PG&E concludes that there need be no removal of any dollar amount for Geysers Unit 15 from PG&E's rate base because the concepts of group depreciation are controlling.

DRA strongly disputes PG&E's analysis and points to Commission precedents that make PG&E's position incorrect. DRA points out that group depreciation is an accounting mechanism for setting depreciation rates. However, DRA believes that accounting methodologies must not override important ratemaking principles, the one at issue here being that shareholders earn a return only on plant that is used and useful. DRA's witness discussed this point:

> "My conception of my testimony here is that PG&E was in compliance with FERC regulations with respect to use of group life depreciation. However, although they were complying with FERC accounting regulation and also Generally Accepted Accounting Principles, my testimony is that rate-making policy is mandated by this Commission, being the Public Utilities Commission. And that overrides FERC accounting regulations as well as a Generally Accepted Accounting Principles when it comes to rate-making policy." (RT 28:2391.)

DRA goes on to point to just two examples where the Commission removed from rate base property that was no longer used and useful. DRA points out that when a plant is prematurely retired, as happened with Geysers 15, the ratepayers pay all of the costs of the plant, even though it operated less than expected. Under those circumstances, shareholders should receive their investment back and a return when the plant operated, but should receive no return on undepreciated plant. DRA points to the first case, regarding PG&E's Humboldt Bay nuclear power plant retirement, for support of this proposition:

> "With respect to PG&E's equity argument, we observe that plants which have exceeded their estimated useful lives have been fully depreciated. Thus, the shareholder already has recovered his entire investment from the ratepayer. The ratepayer who has paid for the entire plant is entitled to receive any additional benefit from the plant's continued operation. In the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits." (D.85-08-046, 18 CPUC 2d 599.)

DRA points out that group depreciation accounting is a convenience to PG&E and other companies that use it. If group depreciation were not used, utilities and regulatory commissions would need to litigate and set individual depreciation rates for each unit. As an administrative convenience, group depreciation is an asset to regulatory commissions and to utilities. DRA concludes, however, that group depreciation is a liability when the utility seeks, as PG&E has done here, to use it to attempt to thwart long-standing regulatory principles. Particularly for an asset of the size of Unit 15, the duty of the Commission and its staff to analyze the retirement costs is critical.

We will once again quote from the Humboldt Bay plant retirement decision to set forth the appropriate used and useful criteria which determine utility eligibility to earn a return on rate base:

> "We agree with staff that Unit 3 is no longer 'used and useful' and should be excluded from rate base. While Unit 3 did operate for 13 years, it will never operate again and can no longer be considered 'useful' utility plant. Unit 3 was entered into rate base under the assumption that it would serve customers for 30 years. Shareholders were entitled to a return and ratepayers were liable for the full ownership cost as long as unit 3 no longer qualified for inclusion in rate base and was eventually and properly removed from the rate base in 1979. We will not deviate from the Commission's well-established principle that only 'used and useful' utility plant shall be included in rate base." (18 CPUC2d 599.)

Additionally, DRA has correctly cited another case where the Commission has rejected a specific argument about group life depreciation. (D.85-12-108, 20 CPUC2d 115, 142.) DRA concludes that Geysers 15 plant is retired and nonfunctional and therefore requires the Commission adopt ratemaking treatment consistent with that status. DRA argues that we are bound to remove from rate base the undepreciated portion of Geysers Unit 15. The dollar value of that removal is estimated by DRA to be $30.2 million. DRA points out that that number was derived from material obtained from PG&E during discovery in this proceeding.

PG&E tries to isolate the two Commission decisions relied on by DRA, arguing that those were exceptions rather than the rule. Unfortunately, PG&E could not point to any other Commission decision that supports its rationale regarding group depreciation.

We conclude that regarding this issue DRA has made a more rational argument consistent with Commission precedent. Therefore, we will adopt DRA's recommendation and remove $30.2 million from rate base to reflect Geysers Unit 15's retirement. We once again endorse our longstanding regulatory principle that shareholders should earn a return only on used and useful plant. We note that DRA's recommendation does provide that ratepayers pay PG&E's shareholders for the entire remaining unamortized plant balance on Geysers 15, but simply not pay a return. We believe our decision is consistent with the Legislature's directives in PU § 455.5, and is fully supported by the record before us.

However, we will allow PG&E to raise its group depreciation argument again in its next GRC if it chooses to do so. The burden is on PG&E to produce a stronger showing.

## 21.3 Operation and Maintenance Expenses Memorandum Account

Our investigation on the Geysers Unit 15 plant put revenue collected attributable to the operation of Geysers Unit 15 into a memorandum account subject to refund. DRA recommends that this amount, now at $36 million, be returned to ratepayers because the costs could not have been incurred by a plant that was not in operation.

PG&E counters that these O&M expenses specific to Unit 15 are only an estimate of a pro rata share of overall O&M expenses that were allocated to Unit 15 in PG&E's last general rate case. PG&E acknowledges that O&M expenses at Unit 15 were certainly less than PG&E had believed they would be during the 1989 GRC; however, PG&E argues that it incurred certain other expenses that had not been anticipated in the last GRC request. PG&E argues that it is precisely because of these unexpected changes that expense dollars are not adopted for specific items, and management is given discretion to redirect the funds as needed. PG&E points out that at no time has DRA argued that there was any imprudence on PG&E's part in the operation and the decision to retire Unit 15.

We disagree with PG&E. Clearly since the plant was not in operation, ratepayers should not pay for costs estimated to be associated with that plant because they were never incurred. Therefore we direct PG&E to refund the balance of the memorandum account over five years as recommended by DRA.

## 21.4 Steam Offset Payments

PG&E points out that despite DRA's conclusion that PG&E acted reasonably in its operation of Geysers Unit 15, DRA has recommended that PG&E not be allowed to recover some $5,028,865 of steam payments made to the Unit 15 steam supplier, GRI. The dispute between PG&E and DRA centers on the offset provision of Section 60 of the steam contract between PG&E and GRI.

The offset formula was based on PG&E's recovery of investment costs for the portion of the plant which remained idle due to insufficient steam. The recovery was collected through a reduction in the monthly payment for steam deliveries. During the period of time that the steam supplier was not supplying full contract quantities of steam, PG&E sometimes enforced the offset provision, and sometimes chose to suspend the offset and pay for the steam received. Because of the pending reasonableness review now the subject of this GRC, PG&E deferred recovery of the offset payments in rates, and recorded the undercollection, including interest, in a subaccount of ECAC for future collection. Despite DRA's conclusion that PG&E acted prudently in its efforts to increase the steam supply and improve unit performance, DRA concludes that these payments were not required by the contract. PG&E points out and DRA agrees that there was a great deal of uncertainty about the enforceability of the offset provision of the contract, with which the DRA disallowance witness has no reason to disagree.

Finally, PG&E notes that its primary concern in deciding to suspend offset payments was that GRI would shut off the steam supply and go into bankruptcy. In fact when PG&E did resume the offsets in early 1989, GRI did shut off the steam supply on April 7, 1989, which led to the eventual retirement of the plant, and went into bankruptcy in addition. This bankruptcy has left PG&E and its ratepayers little recourse against the steam supplier. (RT 26:2298-2299, 2307.)

We agree with DRA's analysis of this issue. DRA points out that from March 1984 through October 1986, PG&E appropriately reduced its Steam payments to GRI. The payments resumed without justification in November 1986 through April 7, 1989. We conclude that PG&E was not required to make these payments under the contract.

22. Lake County Wastewater Pipeline Project Proposal

The County of Lake (County) was a new participant to PG&E's ratemaking proceeding. The County appeared with a very specific proposal for the Commission's consideration. The County appeared in this proceeding urging the Commission to authorize funding in this general rate case cycle of a maximum of $2 million annually for PG&E's participation in the southeast Geysers effluent pipeline project (Project). The purpose of the Project, which will supply wastewater effluent for injection into Geysers steam fields, is to restore and maintain The Geysers geothermal steam resource, a valuable source of clean electric generation, and to provide a means of necessary waste water disposal. The CEC joins the County in recommending the funding of a maximum of $2 million annually for the Project now. The County's proposed Project is described as a solution to the declining productivity of geothermal steam resources at The Geysers. If productivity decline continues unchecked, steam resources in large portions of the reservoir will diminish to the point of nonviability of power generation within 10 to 15 years. (Exhibit 304.) The CEC correctly points out that this decline in productivity cannot continue unabated without causing serious impacts to steam suppliers, utility investment at The Geysers, and the ratepayers. (Exhibit 307.)

For the County, this decline is potentially disastrous. Geothermal power plant generation and geothermal-related employment, goods, and services constitute a major sector of the local economy and source of tax revenue for local government.

The County believes that the seriousness of this problem justifies taking immediate action to mitigate or reverse The Geysers reservoir productivity decline. Thus, these concerns led the County to develop its proposal. The Project in question would deliver treated wastewater effluent to the southeast portion of The Geysers steam reservoir for injection in steam fields serving six power plants, four of which are PG&E Geysers Units 13, 16, 18, and 20. The County and CEC agree that with the use of injected effluent, steam deliveries to these plants could equate to 25 to 50 megawatts of additional capacity at an estimated cost of only 1.5 cents per kWh, an amount significantly less than current utility avoided costs of 3.5 to 4.5 cents per kWh. (Exhibit 304 and Exhibit 307.)

The County conducted a feasibility study of the Project in 1991. Based on that investigation, the County concluded that a 28-mile pipeline carrying 5 to 7 million gallons of effluent per day to the southeast portion of The Geysers would be technically and economically feasible if the costs were shared equitably among benefited wastewater treatment plants, steam field owners, and power plant operators. The County contends that the type of guaranteed long-term effluent supply for augmented injection provided by the Project would also avoid or prevent situations such as occurred at PG&E's Unit 15, which, as was just discussed in the prior section, had to be retired because of insufficient steam supplies. (Exhibit 304.) The cost of the pipeline, exclusive of debt service, is currently estimated at $26 million to construct an approximately $2.2 million annually to operate and maintain. (Exhibit 351.)

Pursuant to the direction of the ALJ, the County submitted a status report on the Project on July 24, 1992. That status report indicates that the parties reached an agreement in principle. The agreement was signed by PG&E, Calpine Corporation, and the Northern California Power Agency. Because of this progress, the Lake County Board of Supervisors voted on July 21, 1992 to sign all three agreements in principle. These agreements are based on the principle that power plant operators will pay steam suppliers for demonstrable net steam increases resulting from the Project.

While PG&E and DRA support the Project conceptually and the agreement in principle in particular, neither of these parties believes that any funding should be provided for this Project in this GRC. Rather, DRA suggests that the funding should be handled in PG&E's ECAC proceeding, although it is unable to recall a Project like this being reviewed in an ECAC case. (RT 55:5131) Likewise, PG&E believes that the Project agreement when in final stages should occur in some "then-appropriate" proceeding.

We disagree with the concerns raised by PG&E and DRA as to the inappropriateness of setting aside funding for this Project in this GRC cycle. We believe we can do so in a way that will protect the interests of the ratepayers yet send the appropriate signal to the parties involved in this Project that it is worthwhile to pursue. It seems particularly appropriate after just discussing the dilemma of The Geysers area generally and Geysers Unit 15 specifically that we be supportive as a Commission of what has been propounded as a likely solution to several problems.

We note that the testimony by County's witness, Dellinger, joined by the CEC, was compelling as to this Project's potential positive value for all parties concerned. This is the kind of public-private partnership that has every hope of preserving and enhancing the very valuable renewable resource of The Geysers. At the same time, this Project can potentially resolve the serious problem of wastewater disposal that the County and other agencies face. The Project has the makings of a win-win situation for all participants, including PG&E's ratepayers.

By indicating our preliminary support for this Project, we do not intend to relieve PG&E of its continuing obligation to negotiate the best deal it can for both its shareholders and ratepayers. We have every indication before us that that is the road that all parties are on. Therefore, we will authorize funding during this rate case cycle for the County Project, of up to $2 million annually beginning in 1994. We select 1994 because the timetable seems unlikely to actually commence in 1993. If PG&E does pursue the project, it may seek recovery in its attrition filings for 1994 and 1995.

However, in the event that PG&E determines that this Project is not in the best interest of its ratepayers, based on information not currently before us, we will allow these dollars in rates subject to a refund in the event that PG&E does not pursue this Project. Therefore we will have this money tracked in a memorandum account. We direct PG&E to report back to us in the next general rate case as to the status of the Project.

## 23. Air Quality Adjustment Clause for NOx Retrofit Cost Recovery

### 23.1 Overview

In 1988, the California Legislature passed a comprehensive California Clean Air Act (CCAA), whose impacts are now being felt on businesses, including utilities, throughout the State. The CCAA states that the priority of consideration should be placed on achieving the goal of healthful air as expeditiously as practicable. The State Air Resources Board (ARB) establishes California's own standards of ambient air quality, while local air pollution control districts have primary authority over nonvehicular sources of pollution. The CCAA requires each air district to develop clean air plans that outline aggressive action to achieve the California ambient air quality standard for ozone. Nitrogen oxides (NOx) can combine with hydrocarbons to form ozone. NOx emissions come from power plants and natural gas compressor stations, among other plants.

PG&E has power plants and natural gas compressor stations operating in the San Francisco Bay Area, Monterey, San Bernardino, Kings, Sacramento, Tehama, Shasta, Colusa, and San Luis Obispo County air quality management districts. Currently, none of these districts meet the state standard for ozone in some locations. The CCAA at a minimum requires that each district reduce area-wide NOx emissions by an average of 5% per year (averaged over a three-year period) until the ambient air quality standards are met.

The air districts where PG&E's power plants are located are currently developing their Clean Air Plans. After these Clean Air Plans are officially adopted and approved by the ARB, the local air districts will proceed to develop and adopt specific rules for the various sources identified in the Clean Air Plan. Each district will conduct public hearings on its proposed rules at which affected parties will be able to provide input. The details on specific equipment to be regulated, startup and shutdown provisions, specific numerical standards, and measuring and monitoring requirements will be developed during this phase of the process.

PG&E believes that because of the stringent requirements of the CCAA, it is probable that each district will adopt the best available retrofit control technology (BARCT) for stationary sources such as PG&E's power plants and compressor stations. At this time, PG&E believes that BARCT will require the installation of the following technologies on its facilities:

1) Selective catalytic reduction (SCR) for most utility boilers. This would be a reduction of approximately 90% over current NOx limits on PG&E boilers when burning natural gas. PG&E also believes restrictions will be placed on the use of fuel oil which is burned during periods of utility electric generation (UEG) gas supply interruptions;

2) Lean-burn precombustion modifications for natural gas compressor reciprocating

engines. This technology reduces NOx emissions by 90%;

3) Dry low-NOx combusters for gas compressor turbines.

PG&E anticipates that beginning January 1, 1993 and no later than January 1, 1994, final regulations for all its boilers and compressor stations will be in place and that the schedule for final compliance will be adopted. PG&E contends that it is cooperating with the regional and local air pollution control districts and the ARB on these matters. PG&E intends to work with the regulators to find the most cost-effective ways of achieving the necessary NOx emission reductions, including nonretrofit options, such as replacement and/or repowering alternatives.

Due to the uncertainty in NOx regulations at this time, PG&E has not fully developed the scope, cost and schedule for various NOx reduction projects. However, PG&E did present its current estimate of NOx retrofit costs by unit class or gas facility. These costs are based on extrapolations of limited data and represent a reasonable high-range estimate of what these retrofits will cost for any given unit class or gas facility. In addition, certain presumptions were made by PG&E in making this estimate: First, that the air districts allow PG&E to implement NOx retrofits during scheduled overhauls. Secondly, that the air districts require NOx retrofits on most units having scheduled overhauls in 1994 and 1995. Third, that generally larger units (330 and 750 megawatt) are retrofitted first. And finally fourth, equipment designers and suppliers can meet PG&E's schedule requirements. Therefore PG&E is currently estimating total plant additions in 1994 and 1995 of $378,558,000. Further, PG&E estimates that nonfuel maintenance and operating costs needed to support the additional equipment at the power plants will be $4.5-7.5 million per year.

Given the large dollars involved, one can see why this issue came before us in this GRC. In the next section we will discuss the mechanism which PG&E, with DRA's support, recommends for recovery of these very substantial NOx retrofit costs.

23.2 PG&E's Proposal

In order to address the large investment that will be made on NOx retrofits, PG&E has departed from the traditional rate case recovery of investment costs associated with the NOx reductions projects and proposed a special ratemaking mechanism. PG&E believes that its proposed air quality adjustment clause (AQAC) is consistent with the ratemaking approach for major projects for Edison authorized by D.87-12-066, (26 CPUC2d 392, 444 (1987)). PG&E agreed with DRA to include certain NOx projects which are forecast to be operational in 1993 in base rates.

Generally DRA has reviewed and supports PG&E's proposal.

Fundamentally the new AQAC mechanism has been proposed because PG&E and DRA believe that traditional revenue recovery through the general rate case is not appropriate for air quality improvement costs at this time because their exact timing and final cost cannot be forecast accurately and they are costs over which PG&E has limited control. Therefore for the NOx reduction products which are placed into service in 1994 and 1995, PG&E proposes cost recovery through the AQAC.

This mechanism satisfies requirements for review of costs of projects over $50 million by using the major elements of a major additions adjustment clause (MAAC) while applying similar treatment for projects under $50 million to deal with uncertainty in timing.

PG&E is requesting, with DRA's concurrence, that the Commission approve a procedure which allows PG&E to begin recording revenue requirement, including maintenance and operating expenses, in the AQAC for each of the projects listed in Exhibit 93 in this proceeding. PG&E proposes that interim rates for each operative project be implemented through advice filings concurrent with the next scheduled rate change (e.g., the annual attrition rate adjustment mechanism). PG&E proposes that interim rates recover the estimated capital-related revenue requirement.

For each project over $50 million, PG&E proposes to file an application to request that the Commission review the costs of the project, the reasonableness of the recorded costs of the project as accumulated in the AQAC, provide direction for final disposition of the balance in the AQAC, and authorize recovery of reasonable project-related costs in base revenues. PG&E proposes that projects under $50 million be reviewed in the next GRC application.

The only opponent to the proposal is CLECA. The principal criticism of CLECA is whether any ratemaking mechanism should be adopted that does not include prior review of the Commission of whether these electric plant NOx retrofit projects should go forward.

Partially in response to CLECA's concerns, PG&E offered during hearings that it would be willing to submit a cost-effectiveness analysis of the project prior to construction, in the form of a compliance filing. Further, PG&E suggested that it may be appropriate to allow a 30-day comment phase to that compliance filing. PG&E did make it clear that it does not wish to bog down its retrofit projects waiting for Commission preapproval. PG&E's most fundamental reason for this position is that it hopes to accomplish the retrofit work while plants are scheduled for other maintenance. PG&E contends, that with the best of intentions, this Commission cannot promise to get decisions on the overall reasonableness of these projects done in a timely fashion to maximize cost savings due to coordination with scheduled outages for maintenance.

CLECA interprets PG&E and DRA's proposal as an attempt to "seek a blank check from the Commission to spend hundreds of millions of dollars on plant additions without prior Commission review." (Exhibit 310.) Fundamentally, CLECA objects that the retrofit investments will be reviewed after the money has been spent. CLECA argues that without prior review of these investments the Commission and the public will lose their opportunity to evaluate other, more cost-effective alternatives to PG&E's retrofit projects. One example of an alternative which CLECA cites would be the decision whether it would make more sense to simply retire the plant. CLECA argues that once the money is spent it is much more difficult to make other resource planning choices. CLECA believes that the cost-effectiveness analysis of any retrofit project must be performed in advance of the investment to insure that the NOx project proposed by PG&E is the most cost-effective option for ratepayers.

CLECA recommends that a prior review program be implemented either in the Biennial Resource Plan Update (BRPU) proceeding or in a continuation of this GRC. Further, CLECA believes that a cost-effectiveness analysis could be undertaken without knowing with certainty the nature of the regulations that will be adopted.

While we share CLECA's concern that PG&E only move ahead with NOx retrofit projects if they are truly cost-effective, we believe that the recommendations of DRA and PG&E take care of this concern. CLECA's recommendations to require pre-review, whether in BRPU or another phase of this GRC, would only submit PG&E to regulatory uncertainty and delay. No party disputes that coordinating retrofit work with planned outages will in the end save ratepayers money. Further, PG&E is under the jurisdiction of the air pollution control district which may not be tolerant of the time it takes to process an application at this Commission.

We note that PG&E did in fact acknowledge the concerns of both DRA and CLECA in its agreement to the following: That PG&E would submit a cost-effectiveness filing six months prior to the start of the plant outage when the retrofits are to be completed, since retrofit work will be coordinated with other maintenance. In addition, PG&E has agreed to submit any retrofits that were to be recovered under the AQAC for the 110- and 120-megawatt units to a cost-effectiveness review prior to the construction of selective catalytic reduction retrofits on these plants. We note that DRA's witness agreed to these cost-effectiveness compliance filings. (RT 29:2557.)

We agree with PG&E and DRA that their proposal is a reasonable compromise that takes into consideration the concerns of CLECA. Due to tight schedules and need for coordination with other outages, it is not reasonable to submit PG&E to a lengthy preapproval process. However, by having a compliance filing on cost-effectiveness made, along with the opportunity for interested parties to raise concerns within 30 days, we put PG&E on notice that it proceeds at its own risk with these projects. Further, even if objections to the cost-effectiveness showings are not made, the burden remains on PG&E to show that the money was well spent to proceed with the NOx retrofit instead of other alternatives with the plant, e.g., retirement.

Finally, we note that CLECA's proposal fails to pass the test of administrative practicality. We are simply not convinced that we can do a thorough review of these projects in the time line that is necessary to potentially save ratepayers the most money. Likewise, we are not writing PG&E a blank check to spend money without eventual review. We put PG&E on notice that it will have to substantiate the cost-effectiveness of its decisions to move forward with NOx retrofit projects. We will not hesitate to disallow dollars if we find in the post-retrofit review that a different alternative would have been more beneficial to PG&E's ratepayers. This will be true whether or not other parties raise concerns with the compliance filings which we order to precede any retrofit program.

Therefore, six months prior to a retrofit program's commencement, PG&E shall file a compliance filing in this GRC docket. Other parties may have 45 days to respond to that compliance filing, either raising concerns or endorsing it.

By creating both the AQAC mechanism and the compliance filing accompanying it, we believe we are protecting ratepayers' interests and at the same time allowing PG&E to move forward with cost-effective NOx retrofit programs.

## 24. Attrition

### 24.1 Overview

Attrition is the year-to-year decline in a utility's earnings caused by increased costs which are not offset by increased rates and sales. In order to protect utility shareholders from the effect of attrition to some extent, the Commission has adopted a ratemaking mechanism called the attrition rate adjustment (ARA) mechanism. The ARA mechanism was set forth in D.85-12-075 to "provide utilities with the reasonable opportunity of achieving their authorized rates of return during years in which they are not permitted under the Commission's rate case plan procedures to file for general rate relief but in which they still face volatile economic conditions." (D.85-12-076, Finding of Fact 1.)

The components of the ARA mechanism as set forth in that decision are:

"1) Update of attrition year labor costs and non-labor costs (materials and services) using the most current recorded and forecasted escalation information;

"2) Adjustment of capital of rate base related adjusted;

"3) Adjustment of miscellaneous changes, such as postal rate changes, payroll tax changes and ad valorem tax changes;

"4) Adjustment of the jurisdictional allocation using the allocation factors developed in the most recent GRC." (D.85-12-076, Finding of Fact 1.)

Both PG&E and DRA have proposed modifications to this ARA mechanism in this proceeding which will be discussed in the sections below. We are not inclined to adopt any of the proposed changes as they have been recommended, but rather will make one slight adjustment.

24.2 PG&E's Proposed Changes

PG&E proposes three specific changes to the current ARA mechanism. First PG&E wishes there to be a specific medical expense escalation due to the fact that medical expenses are escalating far more rapidly than the labor and nonlabor expenses. Second, PG&E wishes the Commission to implement an advice letter procedure to capture miscellaneous changes currently authorized for recovery under the mechanism but only in the attrition year after they become final as a matter of law. Third, PG&E wishes to be permitted recovery of governmentally imposed payments, not currently recoverable in the present ARA mechanism, which are final as a matter of law and exceed $500,000 in annual expenses. PG&E proposes to file an advice letter for such miscellaneous changes and governmentally imposed payments as soon as such changes become a matter of law. PG&E's plan envisions that from the date the advice letter is approved through the end of the year in which the miscellaneous change becomes final, PG&E would debit/credit as appropriate the ERAM or the gas fixed-cost accounts.

DRA opposes all three of PG&E's proposed changes. As to PG&E's first proposed change related to separate escalation of medical expenses, DRA points out that Edison recently proposed a similar modification to its own attrition mechanism. DRA correctly cites D.91-12-076 which rejected Edison's proposal. In that decision, as we shall find here, we agreed with the parties that health care costs are increasing faster than other costs. The dilemma presented for us in approving a separate health care escalation, however, is the fact that health care costs are already included in the development of the nonlabor costs for which we currently allow escalation. Like Edison, PG&E has not separated medical costs from other labor and nonlabor costs. Given the national data compiled to develop the escalation factors which we do use in the attrition mechanism, it seems unlikely that such a separation would be a simple or automatic exercise.

One of the dilemmas facing PG&E and other utilities is that much of their health care costs are captured in what we call the "other" category for attrition purposes. This category, which is separate from labor and the nonlabor category, is not escalated for attrition year purposes. Nowhere in our cases, including our first case on the attrition mechanism, is there any specific allowance for this "other" category to be escalated. Nevertheless, this has apparently been the past practice. We have corrected this error in Edison's last GRC decision, previously mentioned.

However, we are willing to make a slight change to this in order to accommodate somewhat the utility's legitimate concerns over rapidly escalating health costs. Currently, the biggest portion of the "other" category is administrative and general expenses of which health care is a predominant one. Therefore, we will allow PG&E to attribute health care costs which it can identify separately in its A&G accounts as nonlabor costs for attrition purposes only. Therefore, as nonlabor costs, these expenses will receive some escalation.

As to PG&E's two other proposed adjustments to the attrition mechanism, DRA's testimony best sums up its opposition:

> "Attrition allowance should not be construed as a means of risk-free ratemaking. DRA believes that in the interest of fairness, if the Commission is to protect the utility form 'shortfalls' due to the timing of cost changes, ratepayers should also be protected from utility 'windfalls' due to the timing of other cost changes, such as plant additions. DRA

> believes that if one area of cost change is protected by a balancing account treatment, then other areas of cost changes should also be considered. One example of ratepayer protection is the adjustment of the ERAM account for the refunding to the ratepayers any amount of actual return over and above the authorized level.
>
> "DRA is concerned about the additional regulatory burden in reviewing the adjustments to the ERAM account as proposed by PG&E. DRA disagrees with PG&E that the streamlined nature of the review and approval process can be retained. Also, PG&E's proposed modifications to the ARA mechanism amount to less than 0.005% of the total revenue requirement. This is well within the margin of error of an approximation. In the opinion of DRA, to sacrifice the streamlined nature of the ARA mechanism for a difference of 0.005% is counter-productive." (Exhibit 103, pp. 15-7 and 15-8.)

We agree with DRA that we have not been presented with a showing to justify complicating what was intended and still is intended to be a relatively simple mechanism. Additional advice letter filings always add to the regulatory morass. Likewise, as DRA pointed out during hearings, the current mechanism has kept PG&E in a financially healthy state in the last several years. For the most part during attrition years, PG&E's recorded rate of return was actually higher than the authorized return by a healthy margin. (Exhibit 149.) We are unpersuaded by the reasons put forth by PG&E to alter the attrition mechanism that in our opinion has protected both utilities and ratepayers well.

## 24.3 DRA's Proposed Productivity Sharing

DRA set forth, apparently as an afterthought, a major revision to our current attrition mechanism. What is somewhat confusing is that one of DRA's arguments for not adopting PG&E's changes was that DRA supports the current mechanism. However, DRA's proposal regarding productivity sharing is in fact a major deviation from the current ARA mechanism.

As we can best understand it, DRA recommends that during attrition years there be a sharing between PG&E's ratepayers and shareholders of the productivity savings realized by PG&E during those years. Currently, those productivity savings during the attrition years accrue to PG&E. DRA acknowledges that for Test Year 1993 dollars all productivity gains have benefited the ratepayers, not the shareholders. DRA justifies its position because it believes customer growth tends to increase productivity and because output in sales has increased faster than labor and other assets which accompany the growth. DRA believes that ratepayers should share in the benefit of such growth or productivity benefits which stem from reasons other than customer growth.

We must comment on the way this issue arose during the proceeding. DRA's original witness supporting this recommendation, was replaced on this issue. It became clear during the second witness cross-examination that rather than a refined proposal for productivity sharing by DRA, we were presented with the beginning thoughts of an intellectual exercise. In fact DRA's witness described his proposal as "...perhaps the first rejoinder in what might be a long conversation that DRA would have with PG&E apart from this hearing room and perhaps apart from this proceeding." (RT 15: 923.)

We agree with DRA's witness that the proposal is far from being sufficiently developed for further consideration at this time. Nor do we necessarily wish to send a signal that this is an area that would be beneficial to pursue. We must note that it is not our preference for the hearing room to be used as the opening parley in a "dialogue." We recommend that the parties pursue their think-tank analysis outside of our valuable hearing-room time. We reject DRA's productivity-sharing proposal as it has been explained.

24.4 DRA's Labor Escalation Penalty

We have already thoroughly discussed the issue of DRA's position on PG&E's compensation study in an earlier section of this decision. We have already rejected DRA's belief that a zero labor escalation factor is appropriate for attrition year 1994 and 1995. Therefore, we will adopt PG&E's numbers for labor escalation for the two attrition years.

25. DRA's Proposal Re PG&E's Accounts

DRA recommends that PG&E's new accounting system should include FERC account numbers in the general ledger, source documents, and journal entries. (Exhibit 105.) DRA claims that PG&E's current system makes it difficult for DRA to perform an efficient audit of the accounting records because FERC accounts are not on source documents or journal entries. DRA further recommends that PG&E, if it does not comply, be disallowed 25% of the cost of PG&E's corporate accounting department, computer accounting department, in the next GRC proceeding.

PG&E disagrees with DRA's recommendation. PG&E argues that its accounting system does in fact allow DRA to perform its audits efficiently. PG&E points out that the Daily Detail Transaction (DDT) data base used to generate general ledger reports and the reports themselves do include FERC accounts. PG&E argues against DRA's recommendation for the following reasons:

1) FERC accounts are currently available to DRA in PG&E's DDT data base, and have been since early 1990;

2) Detail accounting transaction tapes provided to DRA include FERC accounts; and

3) The cost of implementing DRA's recommendation is estimated to be $30 million in one-time costs and $12 million additional annual costs, which PG&E views as unreasonable in light of alternative ways to meet DRA's needs.

It became clear during hearings that in fact part of DRA's problem was that it had not reviewed material it was given in a prompt fashion. We appreciate the time pressure that DRA is under during a general rate case review. However, DRA indicated that part of the problem has now been solved through PG&E's agreement to add additional information to the detail tapes. PG&E points out that while Edison and Southern California Gas Company (SoCalGas) use FERC accounts, they are not combined gas and electric utilities and therefore have less problems in incorporating FERC accounts. (RT 12:636.) Finally, PG&E promises in a timely manner to provide DRA with any tapes in whatever format that will help DRA's analysis.

We agree with PG&E that it has made a showing that there is no need to change their accounting system. We recommend that DRA more quickly inform PG&E of problems it is having with the data. Likewise, recent improvements made to the system should assist DRA in the future.

As to the areas that the parties were able to reach agreement on in their testimony, we concur. DRA's further requests regarding changes to PG&E's accounting systems we reject.

## 26. Marginal Costs

### 26.1 Overview

It has now been over ten years since this Commission has made a transition from the use of embedded costs to the use of marginal costs for purposes of electric revenue allocation and rate design. The theory behind adoption of marginal costs was that they would provide a better price signal to customers of the impact of their consumption decisions on the utility cost of providing service on a prospective basis and hopefully would induce them to be more efficient. As we stated in our opening section of this decision, the procedural background, PG&E has presented a controversial and thorough alteration to our current methodology of marginal costs. In fact, certain parties were so threatened by

PG&E's proposed changes that they sought to exclude these changes from consideration.

As we discussed earlier, it was appropriate for PG&E to bring forward proposed changes to its marginal cost methodology in its application for a general rate increase. We are adopting today PG&E's methodology. We endorse the ALJ's ruling that this rate case was the appropriate forum for PG&E to bring forth its innovative ideas.

Rather than discuss the position of each party individually we will attempt to divide the parties into the two "camps" revolving around the marginal cost issues. First, joining PG&E in overall support of its program, occasionally with minor modification, are the Agricultural Energy Consumers Association (AECA), the California Farm Bureau Federation (Farm Bureau), the Association of California Water Agencies (ACWA), and the California City County Street Light Association (Cal-SLA). The opponents of PG&E's recommendations are generally DRA, CLECA, CMA, IU, Cogeneration Service Bureau, FEA, and, to some extent, TURN.

We note at this juncture that TURN seems more concerned with the adoption of PG&E's proposed changes at this time rather than the principles involved. Likewise, DRA accepts certain notions of PG&E's showing while not wanting the company's proposal implemented at this time. The strongest opponents to PG&E's proposals are the large industrial user class representatives. Likewise, the biggest enthusiasts of PG&E's proposals are the agricultural class representatives.

In adopting PG&E's overall proposal with some modifications, our goal is to continue to improve our methodology of sending the most accurate marginal cost price signals to PG&E's customers. Because this is our goal, we agree with PG&E's policy principles that marginal cost components should be based on the design and operation of PG&E's system, accurately signal the cost of providing electrical service, be forward-looking, capture the timing and magnitude of future investments, reflect geographic differences where significant, reflect the value that PG&E's customers place on electric service, only include those costs actually incurred by PG&E for revenue allocation purposes, and finally, provide consistent signals in the evaluation of supply and demand resources for planning purposes.

Our goal is to more fairly and equitably allocate responsibility to the several customer classes for recovery of PG&E's embedded revenue requirement. We acknowledge that this revenue requirement is much higher than the sum of all class marginal costs. However we are committed that marginal cost pricing, when refined sufficiently, will send price signals to consumers which will guide resource planning for the future. In fact, a major attraction of PG&E's recommended changes is the forward-looking aspect of its proposals.

PG&E calls its changes to current marginal costing techniques "advancements." We agree that this is how the proposals should be described. We note that there is no party to the proceeding that is terribly enthusiastic about the current system, with perhaps the exception of the large industrial class.

Briefly, PG&E's proposed changes include using a value of service (VOS) approach for estimating marginal generation capacity costs, because the VOS approach directly measures and uses generation-related shortage costs and thus is more economically efficient because it takes into account both supply and demand. Secondly, PG&E proposes to compute separate bulk versus area marginal transmission costs because this results in more accurate marginal costs by reflecting the differing causes of investment for each. Further, PG&E proposes to present estimates of area transmission costs on a system-average basis but still take into account the large transmission projects in certain geographic areas. Third, PG&E would also estimate marginal distribution costs on a 13-division basis because this substantially increases accuracy, thus sending price signals which better reflect the differing costs customers cause PG&E to incur, and furthermore, provides the area-specific data necessary for future targeting of customer energy efficiency (CEE) programs. However, we note that we shall direct PG&E to further refine its original proposal of breaking down its area study to the Transmission Planning Area (TPA) and Distribution Planning Area (DPA) levels in its next GRC. We endorse the concept that more disaggregated data yields better and more equitable marginal costs for different customer classes. Fourth, PG&E suggests using the present-worth costing methodology because it is the only method which estimates the opportunity cost of deferring T&D investments due to a change in load growth, taking into account both the timing and magnitude of such changes. Fifth, PG&E proposes to use regionally disaggregated as opposed to system average marginal customer costs and reflecting the different costs caused by new versus ongoing customers. Sixth, we will exclude residual emission adders from marginal energy costs for revenue allocation purposes.

We acknowledge that our discussion of these issues may frustrate some parties, particularly those that lose issues, given the brevity with which we will discuss them. We note that given the voluminous briefing on this issue, we could have easily doubled the length of this decision for the area of marginal cost and revenue allocation alone. We have no wish to do so. Instead, we will focus on the new changes that we are adopting. The criticisms have been analyzed and considered carefully, even if not described in great length here. It is in large part due to these criticisms that part of our order is to instruct the CACD to set workshops for interested parties to participate in developing tracking mechanisms for capturing the results of the use of this new methodology. We expect PG&E to cooperate fully with other parties in providing data as requested. We expect PG&E to use 1991 data for the workshops. We expect these workshops to conclude by

July 30, 1993. CACD shall submit a report in this docket on the workshop results by September 1, 1993. Parties should state their positions for the workshop report on whether methodological changes need to be made before the next rate case. How we view this issue in PG&E's next GRC will be largely dependent on the level of cooperation PG&E provides to other parties. We will order PG&E to revisit this issue in its next GRC and report to us on the success of the changes it has made and further refinements that we will order today.

In addition we note that today we are only adopting these methodological advancements in marginal cost for PG&E, not other utilities. Likewise, by adopting these changes today we are not suggesting that the current methodology may not be appropriate in other arenas (notably long-run marginal cost (LRMC) for gas). We note that we are embarking on the early stages of LRMC for gas whereas the electric side marginal cost has been in place for many years. The time is ripe for improvements on the electric side. We view our venture down the road that PG&E proposes as a trial run. We are willing to revisit the issue and perhaps change our decisions today based on further information.

We note that we believe both PG&E and the agricultural class representatives have been responsive to the direction given by Commissioner Ohanian in PG&E's last GRC.

> "We have resolved to move rates toward EPMC for all classes, but I am not entirely comfortable with our treatment of agricultural customers. I look forward to the upcoming studies of not only specific agricultural rates but if possible our approach to these rates in general." (Concurring Opinion, 34 CPUC2d 199, 490.)

The agricultural class has argued for some time that the current marginal cost methodology puts an unfair burden on them vis-a-vis their movement towards EPMC. It is clear from the data presented by PG&E in this proceeding that that was in fact the case. By bringing marginal costs down to a more area-specific level, and adopting present worth and VOS methodologies, the agricultural class is closer to its EPMC targets than ever analyzed before. We note that our previous methodology, based on system-wide averages, failed to adequately account for geographic and class-based differences in service costs, and indicated that the agricultural class was between 30 and 60% away from its appropriate EPMC target. PG&E's showing today, with some modifications, indicates that the agricultural class is much closer to its EPMC target than previously indicated. Finally, we agree with the concerns raised by AECA and the Farm Bureau that there needs to be some special treatment of the agricultural class in the ongoing drought period. Therefore we will order CACD to hold workshops to address drought-related disruptions in the agricultural community with the goal being to develop an appropriate mechanism to address these concerns. Likewise, we agree with AECA that we should order PG&E to continue to investigate the validity of current methods of forecasting agricultural sales.

Finally, we will adopt AECA's recommendation that PG&E explore developing special drought-related standby rates for farmers who are forced to develop new well capacity as a result of water-scarce conditions. Unfortunately, we have no indication that the drought will not continue into 1993. It is clear from the record before us that California farmers are deserving of what reasonable relief we can provide them.

We conclude that we can make no progress in the area of more accurate marginal cost pricing if we are not willing to take steps to move forward. We reject the recommendations of the parties who suggested we should simply send PG&E back to "further study these proposals." At some point we must be willing to bite the bullet and move ahead with ideas that we believe are sufficiently developed for implementation. Our order of further workshops and a report in the next GRC should adequately protect the concerns of the parties who have opposed these changes.

We will now briefly discuss the pros and cons of the various components of PG&E's proposed changes.

It may be presumed that on certain minor issues which we do not discuss we have adopted PG&E's recommendation. That adoption is based on a full and complete record.

By way of introduction to the sections below we will quote from our last general rate case:

> "Marginal costs are the change in total costs resulting from a small change in a specified element of the utility's operation. The general rate case considers three general types of marginal costs. Marginal capacity costs measure the costs that change with changes in kilowatts of peak demand. Marginal energy costs vary with changes in kilowatt-hours (kwh) of energy. Marginal customer costs are the costs of providing access to the utility systems, meter-reading, and billing that change as the number of customers changes.
>
> "Economic theory teaches that prices should reflect marginal costs." (34 CPUC2d 199, 313) (1989).)

## 26.2 Marginal Energy Costs

Marginal energy costs are the per kilowatt-hour costs of fuel, operation, and maintenance. At issue in this general rate case are six areas:

1) Whether to use a built-out or barebones resource plan,

2) Whether the calculation should come from a single-year production cost simulation or an average of six one-year production cost simulations,

3) Whether the commodity price of natural gas should be based on Southwest prices or an average of all prices,

4) Whether the gas commodity cost should be forecast on a seasonal or annual basis,

5) Whether the gas transport cost should be based on the long-run marginal cost to PG&E as one company or whether it should be based on the cost to PG&E's UEG department, and

6) How emission adders should be used.

<u>26.2.1 Resource Plan: Barebones vs. Built-Out</u>

The proponents of PG&E's overall marginal cost changes believe that a built-out resource plan is a better method than the barebones plan proposed by the opponents. The issue goes to fundamental resource-planning philosophy. PG&E proposes to employ a built-out resource plan that includes all potential supply and demand resource additions which are found to be cost-effective using Commission-approved methods. PG&E's resource plan includes uncommitted DSM programs which DRA's barebones resource plan excludes. PG&E's uncommitted DSM resources are cost-effective pursuant to PG&E's "two-stage test." This test is consistent with the CPUC/CEC joint standard practice. For supply-side resources, PG&E starts with a barebones plan and then includes new supply-side resources only after they have met the iterative cost-effectiveness methodology (ICEM) test. PG&E argues that by using this Commission-approved procedure, only cost-effective supply-side resource additions are included in its built-out resource plan.

On the other hand DRA, CLECA, and TURN believe that a barebones resource plan will produce marginal costs that will encourage the development of demand-side management and provide an equivalent basis to evaluate both supply- and demand-side resources. PG&E argues that none of these parties have demonstrated how the barebones plan-based marginal costs will achieve their intentions. The opponents argue in favor of a barebones resource plan because it excludes resources not yet committed to be built. They recommend the use of a barebones resource plan so that supply-side resources and company-sponsored demand-side management and conservation efforts are also evaluated against the same resources.

We agree with the proponents that use of a barebones resource plan does not appear to result in the goals advocated by DRA, based on the evidence presented in this proceeding. Therefore we will adopt PG&E's built-out resource plan to develop marginal costs because it more accurately represents how PG&E plans and operates a system. In our DSM OIR/OII, we are currently examining methods to develop a common yardstick for evaluating supply and demand-side resources. For purposes of developing marginal costs in this proceeding, however, we adopt PG&E's proposed approach.

26.2.2 Gas Commodity Costs

All parties who have taken a position on this issue, with the exception of CLECA, recommend that Southwest gas prices be used because "It is reasonable to assume long-term delivered Southwest prices will be a proxy for supplies delivered by other interstate pipelines." (Exhibit 203.) This is an issue because the predominant marginal fuel on PG&E's electric system is natural gas. Therefore, this is an important assumption for estimating marginal energy costs. PG&E and DRA agree that Southwest gas acts as a price leader for both Canadian and California source gas.

On the other hand, CLECA alone proposes that a simple average of Canadian, California, and Southwest gas prices be used for estimating the marginal commodity cost of gas. (Exhibit 330.)

We agree with PG&E and all the other parties who address this issue that it makes more sense to use the price leader, the Southwest, to set the adopted natural gas price for purposes of marginal energy cost analysis. Therefore, we will adopt PG&E's recommendation.

26.2.3 Commodity Cost Forecast

All parties that took a position on this issue, with the exception of CLECA, agree with PG&E that a monthly gas price forecast should be used to reflect recurring seasonal patterns in commodity prices. PG&E observes that gas commodity prices increase in the winter and decrease in the summer. The variation from the highest month to the lowest month is about 27%, clearly a significant difference worth reflecting in marginal energy costs.

CLECA alone proposes using a constant annual price. CLECA acknowledges that the spot price increases in the winter but believes that PG&E's electric department actually maximizes its usage in the summer. PG&E points out that this may be helpful in estimating the average cost of gas but it is irrelevant for estimating the incremental cost of gas, which is the point of marginal cost analysis.

We agree with PG&E that given the recurring pattern of monthly gas price increases and decreases and the expected size of the variation, monthly gas prices provide important detail for improving the accuracy of marginal energy costs. Therefore, we will adopt PG&E's monthly estimates of the incremental commodity cost of gas.

26.2.4 Gas Transport Cost

On this issue, DRA joins PG&E, the Farm Bureau, and Cal-SLA in the position that long-run marginal cost (LRMC) of gas transport should be used to evaluate supply-side resource options. PG&E argues that the long-run marginal cost of gas transport approximates the cost of gas transport that PG&E incurs to meet a small increment of demand. For this proceeding, PG&E used an internal gas LRMC study. When a final decision is issued in the current gas LRMC proceeding (I.86-06-005) on gas marginal costs, PG&E will use the forecast adopted for future supply and demand cost-effectiveness analysis.

CLECA, joined by TURN, believes that PG&E's proposed transportation cost is outdated. Rather, they believe that the incremental cost of intrastate transportation to PG&E's electric department is best reflected in the UEG transportation rate determined by the Commission in PG&E's BCAP proceeding. (Exhibit 330.)

We disagree with CLECA and TURN and find PG&E and DRA's arguments more compelling on this issue. We will adopt long-run marginal cost as the appropriate methodology to develop the gas transport costs.

26.3 Marginal Generation Capacity Costs

Marginal generation capacity costs are those incremental costs for generation which result from incremental load growth. These costs are expressed in dollars per kilowatt of each new kilowatt of demand occurring on the PG&E system. PG&E proposes adoption of a definition of marginal generation capacity costs in this proceeding which is based on generation-related shortage costs which may, in a probablistic sense, be experienced by customers given PG&E's resource planning efforts. Thus, the controversy focuses on PG&E's proposal for adoption of its value of service methodology.

26.3.1 Resource Plan: Barebones vs. Built-Out

We have already discussed the merits of the two approaches. We will be consistent and adopt the built-out resource plan approach advocated by PG&E, the Farm Bureau, AECA, and Cal-SLA for development of marginal generation capacity costs also.

26.3.2 Pacific Northwest Intertie Assumptions

PG&E and DRA have reached agreement on the amount of firm Northwest resources that should be included for the calculation of marginal generation capacity costs. PG&E and DRA propose to use the firm Northwest contracts which have been adopted by the CEC in its 1990 Electricity Report (ER-90), plus a 100-megawatt contract between Western Area Power Administration and PacificCorp that was executed subsequent to the adoption of ER-90. In addition to firm contracts, ER-90 also adopted the use of 700 megawatts of "spot" capacity by PG&E for reliability planning purposes. The total capacity agreed to by DRA and PG&E is 1588 megawatts for the 1993 test year.

Both TURN and CLECA agree that ER-90 assumptions are appropriate but come up with total megawatt capacity that is larger. The difference between the parties arises from the issue of the proper amount of firm Northwest contracts from ER-90 that should be considered. PG&E believes it is improper to include contracts with entities outside of PG&E's planning area.

We agree with PG&E and DRA that their assumptions regarding use of the Pacific Northwest Intertie for firm and spot capacity are the most reasonable presented. Therefore, we will adopt those assumptions.

### 26.3.3 Fossil Unit Availability

A total of 930 megawatts from PG&E's oil and gas generation plants which are currently operating are proposed for standby status by the end of the year 2000. PG&E and DRA agree that these units should be included in the calculation of marginal generation capacity costs, starting with the 1993 test year, and removed from the calculation only when they are actually scheduled to be placed on long-term standby.

TURN and CLECA disagree. CLECA has proposed that units designated for long-term standby status in the longer term should not be included in the determination of the six-year Energy Reliability Index (ERI) forecast. CLECA suggests that many of these units may be retired sooner than projected in part due to requirements to comply with air quality standards.

We agree with PG&E and DRA that it is more appropriate to include these fossil units at this time for calculation of marginal generation capacity costs. While these units may go into standby status, they have not yet.

### 26.3.4 SMUD's Loads and Resources in Planning

PG&E included SMUD's loads and resources in PG&E's planning area for purposes of its reliability analysis and to compute marginal generation capacity costs. In agreement with PG&E's treatment of SMUD loads are the CEC, DRA, and the Farm Bureau. PG&E argues that its inclusion of SMUD's loads and resources in determination of its target reserve margin is technically correct. PG&E contends that proper reliability planning requires that a utility consider the probability that it will receive reserve support from its neighbors. PG&E points out that because of SMUD's size and the fact that the PG&E service territory completely encircles SMUD's, the SMUD system is easier to model than other neighbors.

TURN and CLECA propose that it is more appropriate to exclude SMUD loads and resources. TURN asserts that PG&E's reserve sharing with SMUD is limited. As evidence of this fact TURN presented newspaper articles which it alleges show that PG&E refused to provide SMUD with reserves in August of 1990 when the Pacific Intertie was temporarily unoperational due to fires. However, our record indicates that these articles never mentioned whether SMUD actually requested emergency power from PG&E. (RT 42:3982-3983.)

We find the arguments to include SMUD far more compelling than the arguments of TURN and CLECA to exclude SMUD for planning purposes. Therefore, we will adopt the viewpoint of the majority of the parties.

### 26.3.5 Value of Service Approach vs. ERI-Adjusted Combustion Turbine Proxy

PG&E's proposal to use a VOS approach in the development of marginal generation capacity costs has divided the parties into two camps. Some of the opponents to PG&E's approach argue that while the concept of VOS has merit, it is not yet ready to adopt. PG&E and its supporters disagree.

PG&E argues that VOS is clearly superior to the ERI-adjusted combustion turbine (CT) proxy method currently used by this Commission. PG&E argues that its VOS methodology results in reasonable marginal generation capacity costs of $5.24 per kilowatt-year for test year 1993. PG&E points out that this figure was developed using PG&E's VOS methodology based on sound economic principles by explicitly considering both the value to PG&E's customers of additional system reliability and its cost to PG&E.

PG&E points out that the Commission has accepted the use of the CT proxy in absence of a methodology that directly measures capacity value. In the past, the Commission has instructed PG&E to investigate means of estimating capacity costs that did not rely on the use of a proxy. The Commission has complimented PG&E on its efforts in the past although it has rejected VOS previously as being premature.

PG&E argues it has corrected any deficiencies that existed in its prior presentation of the VOS method. Further, PG&E notes that in addition to the parties that support its immediate adoption (California Water Agencies, the Farm Bureau, Cal-SLA, and AECA), DRA supports the VOS concept in principle.

Briefly, PG&E's proposed VOS method uses customer surveys from which average customer outage costs are determined on a dollar per kilowatt-hour basis. A system average cost for each type of outage is then determined. A reliability model is used to estimate expected unserved energy (EUE) given assumptions about loads and availability of resources. The product of system average customer outage costs and EUE avoided by an increment of capacity addition produces a marginal generation capacity cost, with the underlying resource planning objective being to equate customer outage costs with the cost of additional capacity.

PG&E supports the VOS method because it is the only known method that measures and uses generation-related shortage costs directly in determining marginal generation capacity costs. Further, PG&E argues that the VOS method furthers important marginal costing policy goals. First, the use of VOS in utility planning promotes economic efficiency. Second, VOS is consistent with current adopted planning methodologies for resource planning. The CEC uses VOS in practice for its resource planning. PG&E argues it is a logical extension for the CPUC to adopt VOS and to apply it to revenue allocation and rate design. Finally, PG&E points out that VOS methodology provides stable results.

In addition to the concerns parties express that the studies or the customer surveys used to develop VOS are not yet sophisticated enough, there are other criticisms raised against adoption of the VOS methodology. CLECA in particular strongly disagrees with the use of the VOS approach for developing marginal costs and revenue allocation. CLECA disagrees that it is apparent that there is a link between resource planning and the other areas.

The crux of CLECA's criticism of the VOS methodology for marginal cost and revenue allocation purposes is that there is no free marketplace for electric service. CLECA contends that because PG&E has no choice as to its provider of electricity that this concept of value, on which the VOS methodology is based, does not make sense in the context of a monopoly service. CLECA's witness dismissed value of service as intellectually interesting but fairly irrelevant. (RT 45:4281-4282.)

The AECA, while supporting PG&E's VOS proposal, requests the Commission to go one step further and apply the VOS approach to class-specific marginal generation capacity costs. By doing so, AECA argues that the Commission would correct the interclass subsidies that currently exist as a result of the use of system-wide averages to determine reliability needs. Presently, according to AECA, those classes demanding low generation reliability are subsidizing classes which require a higher level of generation reliability. AECA points out that PG&E's analysis makes it clear that the agricultural and residential classes have long been subsidizing the supply reliability of other customer classes.

Finally, FEA believes that rather than an ERI-adjusted CT proxy, the full cost of the combustion turbine should be used for development of marginal generation capacity costs.

While we are sympathetic with the nervousness expressed by the parties opposing the VOS methodology, we think overall that the arguments made by the parties in favor of the methodological changes have more merit. This is the case particularly in light of our concern that the ERI CT proxy is just that: a proxy until a better methodology is developed.

DRA in particular recommended additional areas where VOS should be developed before adoption. However, the Farm Bureau and PG&E counter that there is nothing gained by waiting for progress in refinement because the end result will not change. We believe given the level of work done by PG&E in this area, combined with the support of other parties, that now is the time to proceed to adopt this methodological change. As for other changes we make today, we proceed on a trial basis, with workshops and a report back in the next GRC as to the success of these methodological changes. These caveats should relieve the concerns expressed by the parties that oppose the adoption of the VOS methodology.

Finally as to AECA's proposal that PG&E's VOS approach should be applied on a class-specific basis, we believe that is not sufficiently developed at this time for adoption. This will be one of the areas that we will direct PG&E and other parties to address in workshops prior to the next GRC.

#### 26.3.6 Combustion Turbine Cost

Despite our adoption of the VOS methodology, we also need to adopt a combustion turbine cost in this GRC. The Cogeneration Service Bureau has reached agreement with PG&E on a combustion turbine cost of $66.12 per kilowatt-year. The large industrial class representatives support this number and DRA has adopted it in its reply brief. Therefore, for the purposes of QF pricing, we will adopt $66.12 per kilowatt-year for the combustion turbine cost.

### 26.4 Marginal Transmission Capacity Costs

#### 26.4.1 Splitting Transmission Costs into Bulk and Area Components

All parties except CLECA, IU, and FEA agree that it is more appropriate to compute marginal costs separately for bulk and area transmission. PG&E has shown that bulk transmission expenditures are caused by system peak load, whereas area transmission expenditures are caused by peak load growth in a particular area. Therefore, the parties who support PG&E acknowledge that the splitting of these two components results in more accurate marginal costs by reflecting these different causative factors.

CLECA developed two main arguments against this proposal. First, CLECA argues that using a voltage distinction is arbitrary and not suitable for splitting transmission into bulk and area, and secondly, that load growth in one area on the transmission system may cause investment in another area on the transmission system. PG&E successfully rebutted both of these points.

We agree with PG&E and the majority of parties that system peak growth causes bulk transmission expenditures and area load growth causes area transmission investment. Therefore, it is more appropriate for PG&E to distinguish between bulk and area transmission for purposes of estimating marginal cost.

The AECA goes one step further and requests that the marginal cost of bulk transmission be set at zero. AECA argues that it is quite likely that all additional transmission capacity over the next ten years will be added to reduce energy costs. Given PG&E's capacity-rich situation, AECA believes it is extremely unlikely that new transmission will be connecting to new generating plants as a means to garner additional capacity. As a result, AECA concludes that any such connections must be assumed to be energy- rather than capacity-related. Hence its conclusion that the marginal cost of bulk transmission should be zero.

PG&E disagrees with AECA's argument that there should be zero bulk marginal transmission capacity costs. PG&E points out that projects such as the Bulk System Reactive Support Project are caused by peak system load growth on the transmission system and are not related to generation tie facilities. Therefore, PG&E argues that its bulk transmission costs, which properly reflect such bulk transmission investments, should be adopted in lieu of the zero cost figure advanced by AECA.

We agree with PG&E that the zero cost figure is not appropriate for adoption at this time. We will adopt PG&E's recommendation in this area.

### 26.4.2 Generation Tie in Bulk Transmission

Generation tie costs result from interconnecting generation sources to the transmission network. Unlike the expenditures included by PG&E in estimating transmission costs, generation tie expenditures are only incurred when new generating resources are added to PG&E's system. As a result PG&E proposes to exclude generation tie expenditures when estimating bulk transmission costs. Joining PG&E are AECA, the Farm Bureau, and ACWA. Not surprisingly, opposing PG&E on this issue are DRA, CLECA, IU, and FEA.

By definition, generation tie-related transmission expenditures are only added when generation is added and a major factor determining the expenditure amounts is the location of the generation. Hence, PG&E argues that generation tie costs are generation-related and should be excluded when estimating marginal transmission costs, for which the causative factor is peak load growth on the transmission system. An argument already mentioned by AECA supports this position, stating that PG&E's current generation capacity-rich situation makes it unlikely that new transmission will be connecting to new generating plants.

The opposing parties all argue that generation tie costs are demand-related and therefore should be included in marginal transmission costs. Further, PG&E does not identify any future generation tie facilities currently projected.

We agree with PG&E and its supporters that it more appropriately prices marginal transmission costs by excluding generation tie costs.

### 26.4.3 Area Transmission Costing Approach

PG&E has identified 25 large load growth-related transmission projects which are planned over a ten-year forecast horizon. PG&E proposes using these projects as part of the estimation of marginal transmission costs. In addition, PG&E proposes to allocate the cost of area transmission projects based on the substations where the load growth is forecast to occur for purposes of revenue allocation. Transmission planning projects (TPPs) are developed as a result of the identification of the specific problem to be solved by local area transmission planners. Each TPP has a distinct study area and PG&E's transmission planners identify the substations which are experiencing the load growth and where the need to construct each of these TPPs is located. PG&E has estimated the marginal cost associated with TPPs by applying the present-worth method to the estimated installed future costs of these facilities. (Exhibit 207.)

Along with these identified TPPs, of which there are 25 in this GRC, a significant portion of load growth-related investment on the area transmission system is not specifically identified. These are generally projects which separately cost less than $1 million and are referred to as background investment. PG&E's calculation procedure starts by forecasting these background investments from 1990 to 2000. Then PG&E uses the present-worth method to estimate the marginal capacity costs. Although PG&E recognizes that area transmission nonspecific background investment varies by area, for this proceeding PG&E presents one background investment value for the whole PG&E system. This is a change from PG&E's original proposal of allocating annuals to the 110 transmission planning areas (TPAs). While PG&E still expects that this area-specific detail may result in more accurate marginal cost, it believes this level of detail was not necessary for use in this GRC. Therefore, PG&E has withdrawn that part of its proposal in an effort to relieve the burden from certain intervenors in analysis.

PG&E's estimate of marginal area transmission cost is $10.10 per kilowatt-year on a system-average basis, which is the sum of the TPP-based marginal cost estimate of $6.29 per kilowatt-year and the background investment-based marginal cost estimate of $3.81 per kilowatt-year.

On the other hand, DRA proposes estimating area transmission costs on a system basis. Since DRA did not use the 25 area transmission projects, it did not use this detail for purposes of its revenue allocation proposals. In addition, the DRA uses the regression/real economic carrying charge (RECC) method to arrive at its estimate of $17.82 per kilowatt-year. The Farm Bureau, AECA, and Cal-SLA all support PG&E's original proposal. While PG&E points out that it still supports in principle its original disaggregated costing proposal, PG&E points out that the impact of moving from PG&E's original proposal using TPAs and distribution planning areas (DPAs) to the current proposal for transmission and distribution (T&D) costs is small. In fact the largest impact is an increase in the allocated cost to the agricultural class of 1.8%.

While our overall goal in changing marginal cost methodology is to improve the accuracy of the numbers, in this instance, we will go with PG&E's altered proposal. However, we wish PG&E to continue to pursue its breakdown to the TPA levels for its next GRC. We find the objections raised to fail to outweigh the benefits set forth by PG&E.

<u>26.5 Marginal Primary Distribution Capacity Costs</u>

PG&E proposes that marginal distribution capacity costs be based on its 13 old operating divisions. PG&E argues that at this level of disaggregation, the resulting marginal costs are significantly more accurate than they would have been using system marginal costs because substantial cost differences in each of these 13 geographic areas can be reflected, but are still manageable enough to be easily used by other parties and in revenue allocation.

In its original showing, PG&E hoped to estimate marginal distribution capacity costs by its 201 distribution planning areas. This is because PG&E's distribution is planned and operated by these 201 relatively independent load centers.

Much attention was spent in the hearing room developing the record that distribution planning and operation is clearly on a DPA basis and that constraints in one DPA cannot be permanently relieved by using distribution capacity in another area. Thus, this provides the conceptual basis for PG&E's area disaggregation of marginal distribution costs.

PG&E points out that in order to accommodate DRA and certain other intervenors' concerns about the amount of detailed data to be reviewed under its initial 201 DPA proposal, the reduction to its 13 former operating divisions already represents a substantial compromise. PG&E argues that its 13-division proposal yields a more accurate allocation to the customer classes than does a single system average figure. PG&E argues that while its original 201 DPA disaggregation yields more accurate results than the 13-division proposal, in PG&E's view that additional accuracy is probably not needed for the specific applications in this case.

PG&E argues that area detail for distribution is important to retain because marginal distribution costs comprise a large percentage of the total marginal costs attributable to capital expenditures. In fact, in PG&E's original 201 DPA analysis, costs ranging from zero in areas experiencing no load growth to over $100 per kilowatt-year in high-growth areas were observed. (RT 34:3030-3031.) PG&E points out that the range is less under the 13-division proposal, but still shows substantial geographic differences in marginal costs across PG&E's service territory.

The opponents to PG&E's overall program believe that marginal primary distribution capacity cost should still be determined on a systemwide basis. Likewise, the agricultural class and ACWA would like the Commission to adopt PG&E's original proposal of disaggregation to the 201 DPA level. We think PG&E's secondary proposal is a reasonable compromise at this time between the two extremes. As we stated regarding the 110 TPA disaggregation, we would like PG&E to continue to pursue this disaggregation for its next GRC. Workshops will be held in the interim to allow intervening parties to develop a comfort level with this level of disaggregation. We believe that the increase in accuracy that has been indicated by the record developed in this proceeding makes the efforts which all parties will have to expend in this area worthwhile. For now, we will adopt PG&E's 13-division approach.

### 26.5.1 Distribution Expenditures

PG&E proposes dividing distribution expenditures into large projects, as identified by distribution planners, and smaller background investments which remain relatively constant from year to year (annuals). PG&E proposes to use forecasts of upcoming large distribution projects, where the survey data from the distribution planners indicated that this was appropriate, while using historical accounting data to project the smaller and more stable annuals. PG&E argues that the use of forecasts for large projects reflects the location and magnitude of these costs much more accurately than historical accounting data alone. PG&E acknowledges that, while it is evident that investment plans are subject to revision, it is equally evident that area distribution planners can anticipate the timing and magnitude of large projects because of their knowledge of local distribution capability and local load growth. Because the development of marginal cost requires a look into the future, PG&E believes its proposal using future plans forms a better basis for estimating future large project-related costs than would using simple extrapolations derived from recorded accounting data.

The opposition once again disagrees, arguing that aggregate distribution expenditures are a better estimation mechanism. DRA argues that the current system of estimating distribution expenditures by correlating system load-related costs over a 15-year period (10 years historical and 5 years forecasted) is a superior method to PG&E's recommended change. DRA argues that PG&E's proposal, based more heavily on forecasting, has a greater potential for inaccuracies and personal bias than already exists. DRA believes that large one-time-only transmission and distribution investments should not be closely associated with load growth over short time periods.

We believe, in keeping with our overall commitment to give PG&E's proposed changes a trial in this GRC cycle, that its proposal is justified. We believe PG&E's foreward-looking approach will have greater accuracy in estimating marginal primary distribution capacity costs.

### 26.5.2 Number of Years of Historical Accounting Data for Estimate

PG&E used seven years of historical data at the 13-division level to forecast the marginal costs associated with the distribution annuals. (Once again, annuals are small investments in distribution capacity to meet load growth. They are not identified individually.) PG&E altered its original proposal, where its forecast was based on only one year's worth of data. Still supporting the use of one year of data are AECA, ACWA, the Farm Bureau, and Cal-SLA.

PG&E expanded its base to seven years in response to the criticism of the other parties that wanted to use the traditional ten years of historic data.

We believe PG&E's use of seven years of data is a good compromise and yet is in keeping with its overall effort to make marginal costs more forward-looking.

### 26.6 Marginal Secondary Distribution Capacity Costs

Estimates for marginal secondary distribution capacity costs were not discussed at length in this proceeding; however, it's reasonable to assume that the parties have the same positions with respect to marginal secondary distribution capacity costs as they do for marginal primary distribution capacity costs. PG&E proposes adoption of estimates of ongoing and new business secondary distribution marginal capacity costs calculated by division using the present-worth method. DRA appears to propose estimates of ongoing secondary distribution marginal capacity costs as a system average using the currently adopted regression or RECC method. As we did in the primary distribution capacity costs we will adopt PG&E's proposal.

### 26.7 Present Worth vs. Regression/Real Economic Carrying Charge (RECC) Methods

This is an area of major contention between the two camps. PG&E proposes that marginal transmission and distribution capacity costs should be estimated using the present worth (PW) method instead of the currently adopted method. PG&E argues that the present worth method uses a resource plan to estimate the marginal capacity costs. This method calculates the difference in total cost of meeting a change in load that begins next year instead of this year. This means that if there is a reduction in demand that postpones the need for the next investment, it will postpone the need for all future investments as long as demand is reduced. (Exhibit 100.)

PG&E argues that its proposed PW method represents a significantly more accurate method of capturing the actual value of capacity to PG&E's customers. The basis for using the PW method to estimate the value of T&D capacity is that it emulates the planning process that actually occurs in the development of distribution capacity expansion plans. PG&E plans for a level of capacity sufficient to meet expected load growth over a number of years.

PG&E points out that to the extent that load is expected to grow, investments are often larger than necessary to meet short-term needs to take advantage of economies of scale. However changes in load generally result in deferral of planned investments. PG&E argues that the value of this deferral is captured directly by the PW method. This value changes from year to year as the opportunity to defer different levels of investment changes from year to year.

On the other hand, the currently adopted method uses a regression approach to estimate the marginal investment per kilowatt of peak demand. It then amortizes the marginal investment by multiplying the marginal investment cost by the RECC. This approach is favored by DRA, CLECA, FEA, and IU. TURN takes no position on this issue.

Under the current method, the marginal cost for each type of capacity is developed using the same regression method. First the annual cumulative investment for the portion of the T&D system under study for ten historical years and five forecasted years is identified. Then the cumulative change in loads during that same period of time is identified. The cumulative costs are regressed against cumulative loads and the slope of the resulting line represents the marginal costs of capacity for the portion of the T&D system under study. The marginal cost in dollars per kilowatt is then levelized using the RECC factor. This method creates an annual amount in dollars per kilowatt-year that is equivalent in real terms to the investment in dollars per kilowatt. Ongoing expenses such as A&G and O&M are added to the annual amount.

Thus, the existing RECC method captures the full cost, rather than the deferral value, of generation capacity costs amortized over each year of the life of the asset. PG&E argues that the full cost of an investment is equivalent to the permanent deferral value of an investment to perpetuity. PG&E does not believe that the lifetime of changes in demand that are represented by typical consumer choices, like the purchase of efficient refrigerators, or the majority of end-use loads, have infinite lifetimes. PG&E argues that the PW method can be used to specify the number of deferral years that is appropriate for the application. PG&E believes its choice of 11 years is closer to the variety of both long- and short-run changes in demand that are reflected in consumer choices of energy-using equipment.

PG&E argues that the PW method produces a more accurate estimate of the actual value of capacity at any specific point in time, or as an average over the course of the plan. PG&E believes it is clear that the PW method represents a significantly more accurate method for estimating the value of capacity for actual distribution plans in area-serving loads where the duration of the change in demand is finite. PG&E concludes that the PW method alone accounts for future replacement of investments and discounts future investments to the present.

The opposing parties are generally against what they view as more reliance on forecasting under PG&E's proposal than under the current methodology. Likewise, the opposition argues that the current methodology renders its results less sensitive to data errors.

We will adopt PG&E's present worth method for estimating marginal transmission and distribution costs. By doing so in this decision, we are not determining that this is necessarily the appropriate approach to use in our long-run marginal cost gas proceeding, because the records developed in these two cases are different. We agree with PG&E that the PW method captures the lumpiness of capacity additions to the T&D system. Secondly, the PW method does not assume the change in demand which drives capacity additions lasts forever. A third reason for adopting the PW method is that it makes use of data that is forward-looking.

We find that the record in support of the methodological change developed in this proceeding is full and complete and justifies our adoption of the present worth method.

26.8 Marginal Customer Costs

PG&E proposes region-specific costs because they are more accurate than system-average costs for four reasons. First, region-specific costs better reflect regional variations in population and housing density. Second, they reflect the extent of overhead versus underground installations in such regions. Third, different transformer sizes, due to at least in part different climates in each region, are reflected. And fourth, for the residential class, the relative percentages of single- versus multi-family dwellings in each of PG&E's six regions is a factor.

Once again, the line-up of the parties on this issue is the same, with DRA, TURN, and the large industrial class representatives recommending that marginal customer costs stay on a system-average basis.

The opposition states that the use of region-specific customer costs are not necessary because the cost differences for many classes of customers are not that large. Furthermore, these cost differences are rendered minimal by the revenue allocation process. (Exhibit 330.)

PG&E counters this argument by stating that for every customer class for which region-specific values are proposed, significant variation is shown with the possible exception of CLECA's members (the E-20 class).

In addition PG&E's proposal is criticized because for marginal customer costs six regions are proposed for disaggregation, rather than 13 divisions. However, the proponents, in other areas, also object to the 13-division disaggregations.

We believe it is important to maintain consistency in our overall support of PG&E's move to more disaggregated data. However, we do not believe that this means that for each category or issue we must disaggregate the data to the same degree. PG&E's reasons for disaggregating marginal customer costs to region rather than division levels are justified. Likewise the criticisms raised by the opposition are not compelling. We will adopt PG&E's recommendation for marginal customer costs to be determined on a six-region basis.

27. Revenue Allocation

Overall PG&E's revenue allocation proposals mirror the changes PG&E has made to marginal cost methodology. PG&E's proposed revenue allocation continues to use the Commission's adopted equal percentage of marginal cost (EPMC) methodology for allocating PG&E's total revenue requirement among the various classes. PG&E argues that its proposal makes substantial advancements in calculating the marginal cost revenues which determine these allocations. Specifically PG&E proposes three major improvements in the determination of class marginal cost revenues:

1) The use of the VOS-based generation capacity costs;

2) The incorporation of area-specific costs and loads; and

3) The calculation of marginal customer costs based on the incremental cost of providing customer access.

PG&E argues that all three of these changes provide more accurate estimates of PG&E's costs to serve its various customer classes, thereby promoting a more accurate and equitable allocation scheme. PG&E argues that since marginal costs were first adopted more than a decade ago by this Commission, the estimating methodology has been constantly evolving. PG&E believes that the changes it has proposed in this proceeding produce accurate marginal costs which better reflect PG&E's true marginal cost of service and marginal cost revenue requirement than do prior methods.

Overall, we agree with PG&E's representations and analysis that the changes we are adopting today to marginal cost methodologies as they relate to revenue allocation issues in fact create a more accurate picture. We note that by doing so the picture as to how close different customer classes are to EPMC has altered. The one customer class which receives the biggest impact from these changes is the agricultural class. In the past the agricultural class has disputed the old methodology's results concerning the agricultural class's distance from EPMC. The showing by PG&E, AECA, and the Farm Bureau in this proceeding indicates that the agricultural class's objections to the prior methodology were well founded. The agricultural class is far closer to EPMC using the more accurate and refined methodologies presented in this case than was ever thought before.

### 27.1 Marginal Energy Costs

#### 27.1.1 Residual Emission Adders

PG&E believes that emission adders should not be included in marginal costs used for revenue allocation. The lineup of other parties on this issue is different than on most issues. DRA, joined by the farm representatives, TURN, and the ACWA all believe that 25% of the residual emission adder should be used in marginal energy costs for revenue allocation purposes.

PG&E and the industrial users' representatives oppose the inclusion of such social costs in its revenue allocation because it argues that the prices of customers' alternatives do not similarly reflect these costs. PG&E believes this is contrary to its stated policy that marginal costs should reflect a competitive market situation. The proponents of inclusion of emission adders point out that many aspects of rate-making lead to distortions in revenue allocation, the major one being the requirement to allow PG&E the opportunity to earn its full revenue requirement, since it is approximately twice marginal cost revenues. TURN and AECA argue that the Commission should take the necessary steps to further its policies on externalities and include them in the calculation of marginal energy costs for purposes of revenue allocation.

We concur with PG&E, CLECA, IU, CMA, and FEA that it is inappropriate to include residual emission adders for revenue allocation purposes at this time. We agree with CLECA that emission adders have a potentially large impact on the allocation of revenue requirement between the several customer classes. Further, we are concerned that the inclusion of adders in the marginal energy cost for revenue allocation purposes would substantially increase the risk of bypass. PG&E correctly points out that its customers' alternatives do not include these costs.

The subject of emission adders is one that is worthy of further study but not ready for implementation at this time.

<u>27.1.2 One- or Six-Year Average</u>

On this issue DRA stands alone in recommending a six-year average marginal energy cost. PG&E and all other parties who took a position on this issue agree that a one-year marginal energy cost allows marginal energy costs in the future to reflect changes in gas prices, the resource plan, and in the forecast of hydroelectric generation. These updated forecasts will result in more accurate marginal energy costs than DRA's methodology. We agree with the parties that the one-year marginal energy cost is a more accurate figure.

<u>27.1.3 Area-Specific Loss Factors</u>

PG&E argues that its area-specific loss factors are reasonable and should be adopted. It points out that one of the primary advancements it has proposed in this proceeding is the incorporation of area-specific information to achieve greater accuracy in marginal costing. We note that we have agreed with this analysis in resolution of many other issues, and intend to do so here.

Once again the argument against disaggregation is that the benefits are small relative to the added complexity that area-specific loss factors create. Likewise, once again, we reject this as a reason to not attempt to improve our marginal cost revenue allocation analysis. We adopt PG&E's area-specific loss factors as an improvement to the current approach.

### 27.2 Generation Capacity

#### 27.2.1 Class-Coincident Demands for Revenue Allocation

For revenue allocation purposes, PG&E argues that in order to be consistent with our adoption of value of service estimates in the marginal cost arena, a minor change needs to be made for revenue allocation purposes. PG&E argues that along with the adoption of the VOS methodology for calculating marginal generation capacity costs, the Commission should also adopt PG&E's relative shortage value (RSVAL) weighting proposal. No party disagrees that weighted loads should be used to develop the coincident demands which are used to calculate generation capacity cost revenues. The only issue is whether the hourly weights should be based on RSVALs or loss-of-load probabilities (LOLPs). The lineup on this issue is similar to how the parties aligned themselves regarding the VOS method.

PG&E argues that its RSVALs are superior to the currently used LOLPs because they assess the probability of each of the three types of emergency action included in California's electric emergency plan. Each of these probabilities is in turn weighted by the estimates of customer outage costs developed by PG&E's VOS methodology. The sum of these three weighted probabilities is the hourly RSVAL. In contrast, PG&E argues that the LOLPs do not distinguish between the different types of outages.

PG&E correctly points out that DRA has admitted that there is little difference between the two methods for the purpose of computing coincident loads. Further, DRA's witness acknowledged that if the Commission adopts PG&E's VOS methodology for calculating generation capacity costs, it makes sense for the Commission to also adopt the RSVAL weights. Therefore, we will adopt PG&E's proposal in this area to maintain consistency with our decisions regarding the VOS methodology.

### 27.2.2 Six-Year Average for Revenue Allocation and Rate Design

PG&E proposes that a six-year average generation cost be used for revenue allocation. PG&E believes, and the Commission concurred in its last GRC, that the six-year average provides a reasonable balance between the long-run and short-run assessments of the need for cost of generation capacity. (34 CPUC 2d 199, 317 (1989).) The Farm Bureau recommends a three-year average while the FEA suggests that no adjustment be made to the cost of a combustion turbine for short-term excess capacity.

We disagree with the two proposed changes, believing there is not adequate evidence in the record to support elimination of the six-year average or to ignore resource planning assumptions.

### 27.3 Area Loads vs. Past Load-Estimating Methods

PG&E has proposed the introduction of class geographic cost differences (area-costing) into revenue allocation to more accurately reflect PG&E's costs and provide the basis for pricing options that better integrate demand- and supply-side planning. PG&E argues that this proposal is in line with the Commission's role of promoting equity and economic efficiency through more accurate costing estimation.

To complement the development of area unit marginal costs previously discussed, PG&E proposes the estimation of geographic loads (AREALOADs) by customer class for revenue allocation. PG&E has developed the AREALOAD method of load estimation for this purpose. AREALOAD extends the current adopted CLASSKW method by using the same information on a more disaggregated level. PG&E points out that this feature allows AREALOAD to generate estimates of class share of area-specific peak demands. PG&E believes these area-specific demands are essential for the introduction of area costing in revenue allocation in order to provide more accurate price signals to PG&E's customers. (Exhibit 17.)

Generally supportive of PG&E's proposal are DRA, ACWA, AECA, Cal-SLA, and the Farm Bureau. Not surprisingly, other parties have opposed it, favoring instead the continued use of the CLASSKW method. The opposition claims that AREALOAD is too complex and data-intensive to be adequately tested and verified. PG&E points out that all parties agree that area-specific load estimates are a necessary improvement. PG&E argues that better utilization of existing disaggregated data allows direct estimation of TPA and DPA loads. In contrast, CLASSKW estimates system average class loads. AECA said it best: the AREALOAD study meets a clear and present need, and warrants immediate Commission approval. DRA also agrees that it is eager to incorporate direct estimates of distribution and transmission loads into its revenue allocation methodology.

PG&E argues that, given this conceptual support and given what in its view is the accuracy of its area-load estimates, that they certainly should be used at the division level. We agree with PG&E that it has adequately shown the accuracy of its area-load estimates. (Exhibit 17.) Despite the fact that a level of accuracy has been achieved at a very disaggregated level, PG&E proposes to use this data only after it has been aggregated back to the 13 division levels.

Finally, PG&E counters criticisms that AREALOAD and its other proposals form a "black box" that cannot be adequately tested, by pointing out that the AREALOAD method uses the same voluminous data as CLASSKW, but at a more disaggregated level.

Finally, PG&E responds to a continuing theme of its opposition that a new methodology must pass a higher standard to replace an adopted methodology. The opposition parties argue that a new methodology must be shown to be clearly superior before it can replace an adopted methodology. While PG&E is confident that its changes recommended in this GRC, and specifically its AREALOAD methodology, meet that test, it disagrees with the underlying premise that any new method must be judged clearly superior to the old method. PG&E argues that this is an excessive burden that would only hinder the evolution of regulatory improvements.

We agree with PG&E and note that the parties have given no citations for this theory other than the human desire to resist change generally. We find in this proceeding that the changes as promoted by PG&E are in fact in the best interests of the ratepayers of California in moving forward towards more accurate marginal cost analysis. More accurate marginal cost analysis will likewise result in fairer revenue allocation policies.

### 27.4 Marginal Transmission Capacity Costs

PG&E proposes separating local from bulk transmission costs in revenue allocation. PG&E argues that this proposal is fully consistent with the way in which customers cause PG&E to invest in capacity. When a customer increases demand at the time of its generation system peak, PG&E incurs an incremental capacity cost equal to the customer's change in load times the cost of generation capacity, plus any additional transmission investment incurred to transport the incremental load to local transmission areas. PG&E identifies these additional costs as the costs of bulk transmission capacity. Following this reasoning, PG&E proposes to allocate the cost of generation capacity and bulk transmission together.

Only in the very rare case where the peak on the local transmission system corresponds exactly with the time of the generation peak would a customer's peak on the generation system indicate the cost to PG&E of providing local T&D capacity for that customer. Consistent with the marginal cost positions of PG&E, causative factors should be used to develop marginal costs and assign them to customer classes. Therefore, in the case of local

T&D systems, PG&E uses customer peaks on the local T&D systems to assign those local costs to customer classes.

PG&E proposes to use the same loads for bulk transmission as were used for generation capacity: the RSVAL-weighted coincident demands. The parties who supported PG&E in the VOS area are in agreement with PG&E here. Likewise, PG&E acknowledges that if VOS was adopted for marginal cost purposes, PG&E's proposal for this area should also be adopted.

CLECA, on the other hand, believes that bulk and area transmission capacity should be aggregated. PG&E argues that CLECA's proposal should be rejected because it would assign bulk transmission costs to customers based on local transmission system peaks which may or may not coincide with peaks on the bulk transmission or generation system. We note that TURN, while not supporting PG&E's proposal, argues that it merits further study.

Likewise, the farming interests in this proceeding, the Farm Bureau and AECA, would like to see bulk transmission costs set at zero due to their belief that the cost of bulk transmission is a function of the amount of energy that a customer uses. These parties argue that, absent the need for additional capacity, any bulk transmission additions would be for energy-related reasons. PG&E argues that the Farm Bureau and AECA's argument should be rejected based on the grounds that bulk transmission cost is in fact load-growth related. We agree with PG&E.

### 27.5 Marginal Primary Distribution Capacity Costs

All parties that support the use of area loads agree that DPA loads should be used to allocate the distribution expansion plan-related project costs.

The selection of loads for use in allocating the costs of small investments in distribution capacity due to load growth (annuals) has attracted much attention because the choice of loads can change the allocation target for the agricultural class by up to 11%. (Exhibit 233.) The annuals account for approximately 75% of the total primary distribution marginal costs. PG&E and AECA propose that the marginal cost revenue of the annuals be calculated using DPA loads.

On the other hand, DRA proposes that the marginal cost revenues of the annuals be allocated using 50% DPA loads, and 50% final line transformer loads. CLECA proposes that the Commission use customer loads at the time of the individual feeder peaks.

The parties acknowledge that using the correct loads for allocating annuals is difficult because of the lack of available data about the loads on the facilities which comprise the annuals. PG&E points out that reliance on final line transformer (FLT) load factors puts an unfair burden on the agricultural class. Because of the poor FLT load factors of the agricultural class, using FLT loads would assign a proportionally larger share of the costs for annuals to agriculture than it would on the other classes. Using DRA's proposal, the agricultural class's target would increase by 11% by using 50% FLT loads. Therefore, given the uncertainty surrounding the annuals issue, PG&E's position has been to exercise caution by using 100% DPA and 0% FLT loads for the annuals.

CLECA has its own proposal, recommending that marginal cost for annuals be assigned based on class contributions to feeder peaks. However, this proposal would be reasonable only if all investments in annuals were made for major feeder trunk lines. PG&E has pointed out that the greater share of load growth-related capital spending on the annuals is on smaller additions to distribution circuits and for primary feeders to serve new customers. Further, CLECA's desire to use feeder loads is even more disaggregated than PG&E's use of 201 DPAs. PG&E testified that there are about 1500 transformers in PG&E's service territory with at least one feeder for every transformer. (RT 40:3849.)

We agree with PG&E and the parties supporting it that there is a lack of theoretical basis for CLECA's position.

Likewise, we are unpersuaded by DRA's recommendation in this area. We will adopt PG&E's use of 100% DPA loads for marginal primary distribution capacity cost calculation.

27.5.1 Exclusion of Dedicated Substations

This is an issue on which many parties had no opinion. PG&E believes it is appropriate to exclude dedicated substation customers from the calculation of marginal primary distribution capacity costs on the grounds that its planners do not include these customers in their area expansion plans. Customers excluded from an expansion plan cannot therefore affect the plan's load.

Despite this, both DRA and CLECA believe that these dedicated substations should be included in developing marginal primary distribution capacity costs. PG&E argues that the position of DRA and CLECA ignores the fact that marginal capacity costs are meant to signal the incremental cost of a customer's increase or decrease in demand. In the case of dedicated substation customers, changes in their demand do not affect the DPA. Therefore, PG&E concludes that their marginal cost should be zero.

We agree with PG&E that if planners exclude dedicated substations from their determinations about growth needs, these dedicated substations are properly excluded for revenue allocation purposes.

27.6 Marginal Secondary Distribution Capacity Costs

In this area for revenue allocation purposes there is general agreement among the parties, or at least no active opposition to PG&E's proposal to use 100% final line transformer loads for development of these costs. Only PG&E presented area-specific FLT loads and no party opposes their adoption. However, the farming interests, AECA and the Farm Bureau, recommend that zero secondary capacity costs be assigned to the agricultural class.

The farmers argue that currently the agricultural class is being misallocated approximately $3 million of marginal secondary costs. The farming interests rely on PG&E's own definition of marginal secondary distribution costs for the reason it should not apply to their class. Secondary distribution capacity costs are the secondary distribution system costs associated with load growth only, and not with providing customer access to the electric system; hence, PG&E's reasoning that they should continue to be based on FLT demand. AECA argues this definition shows the cost responsibility for these investments should be assigned to those classes where incremental upgrades to FLTs are needed because of load growth or from existing customers.

While we are concerned about the issues raised by AECA, we believe the record does not yet reflect enough support for their adoption. We order this issue to be explored in the workshops arising out of this decision.

## 27.7 Marginal Customer Costs

In support of PG&E's proposed changes to marginal customer costs for revenue allocation purposes, TURN joins PG&E's standard supporters.

Marginal customer costs are the costs associated with providing customers with access to the electric system: hooking up a customer to the system, maintaining the hookup equipment, reading the meter, sending the monthly bill, and maintaining customer records. PG&E has proposed two changes to the way marginal customer cost revenues are calculated. First, PG&E proposes to assess the cost of new hookups based on the number of new customers in each class because these are the very customers that impose this cost on the utility. Secondly, PG&E proposes to assign the full cost of the hookup, rather than an annualized cost, since the investment is sunk once the facilities have been installed (Exhibit 17).

DRA, joined by CLECA and other industrial customers, disagrees with PG&E's proposal to assign a portion of marginal customer costs associated with new customer hookups on the basis of new customer class rather than the total number of customers in the class. DRA believes that allocating hookup costs only to new customers in a class results in more costs being allocated to classes which are growing more rapidly. DRA recommends that the status quo be maintained in this area.

PG&E disputes DRA's objection to charging a fast-growing class more than a slow-growing class. PG&E says that it is exactly the growth in customers that causes PG&E to incur hookup costs and that the more hookups in the class, the more costly it is to PG&E. PG&E stresses that marginal costs should be based on causative factors, meaning that customer classes should be assigned costs based on how their usage imposes costs on the utility. PG&E concludes that since the costs associated with hooking up a new customer are driven by the number of new hookups, the marginal costs must be assigned based on the number of new hookups in a class.

We agree with PG&E that its changes to the calculation of marginal customer costs are an improvement over our current methodology. We also note that it has wide support from both the farming community and TURN.

<u>27.8 Revenue Allocation for Standby Customers</u>

PG&E and CLECA developed the two opposing positions on this issue. PG&E maintains contracts with standby customers to provide backup and maintenance power in case of outages. Because of these contracts, area planners must plan capacity sufficient to meet the erratic needs of the standby customer. The theory underlying PG&E's analysis is that the more standby customers there are in an area, the less likely it is that all customers will suffer generation outages at the same time. PG&E states that this lower likelihood could then be translated to the percentage of the total standby reservation capacity that the area should plan for. PG&E then adjusted the capacity downward to reflect the fact that some outages are already reflected in the historical data. PG&E

believes that to neglect this adjustment would assign costs twice to the historic standby loads. PG&E applies the diversity and historical usage adjustment to generation and bulk, TPP, TPA, and DPA costs. (Exhibit 229.) On the other hand, CLECA's standby adjustments use the current coincident/noncoincident splits from the 1990 GRC. CLECA's adjustment factors do not take into effect the operating characteristics of standby customers nor the location of the standby customers throughout PG&E's service territory. CLECA's proposal is based on a load-splitting methodology as follows: 100% of secondary distribution and FLT loads, 57% of primary distribution loads, and 6% of medium light and power, E-19, and E-20 area transmission loads.

We believe PG&E's proposal is more in keeping with our desire to make marginal cost and revenue allocation more area-specific in this GRC. We will adopt PG&E's recommendation for revenue allocation for standby customers.

27.9 EPMC Revenue Allocation with Appropriate Caps and Floors

No party disagrees with our continued and dedicated movement towards EPMC target allocations. However, all parties are in favor of some sort of combination of caps and floors to mitigate the rate impacts. In the last GRC, this took the form of a capped EPMC allocation. Almost all the parties to this GRC support continuation of this approach, with the exception of TURN. PG&E sees TURN's proposal for an interim system-average percentage change (SAPC) allocation as a backhanded way to reduce the revenue allocation to its constituents, the residential class, that is a result of PG&E's more refined area-specific load and cost estimates.

PG&E, joined by its usual supporters in this area, believes the cap for all classes except streetlighting should be set at SAPC plus or minus 3%, striking a fair balance between movement towards EPMC and the prevention of overly large rate swings. However, PG&E notes that should the adopted system level increase be less than 5%, PG&E would recommend that the Commission adopt a cap of SAPC plus or minus 5% cap for class-level revenue allocations.

DRA believes that the appropriate cap should be of SAPC plus or minus 5%. The industrial customers as a group prefer a cap of SAPC plus 5% with no floor. Finally, Cal-SLA believes a cap of SAPC plus 3% is appropriate but with no floor to any decrease.

Given the size of the rate increase that we are authorizing today, we believe PG&E's recommendation of SAPC plus or minus 3% is appropriate and will not result in onerous rate changes.

28. <u>Agricultural Class Drought Relief</u>

This issue was raised in this proceeding by the ALJ, requesting the parties to present ideas of what could be done to alleviate the undisputed negative impacts of the ongoing drought on the agricultural class.

In response to this request, AECA set forth four proposals:

1) AECA recommends that the Commission should adopt a mechanism to address disruptions in the agricultural community related to surface water supply scarcity. Possible policies to address this problem include, but are not limited to, developing an agricultural class electricity balancing account similar to the ERAM or developing a payment deferral program.

2) Until such policy is implemented the Commission, according to AECA, should order PG&E to develop better methods with which to forecast agricultural electricity use.

3) During drought years in which the agricultural class is considered to be below its EPMC revenue allocation target, unless compelling reasons require otherwise, the Commission should adopt revenue allocation caps for the agricultural class that are system-average percentage change.

4) The Commission should develop a special standby rate for farmers who, because of short-term surface water supply scarcity, are developing new well capacity.

No participant in this case has challenged the evidence presented by AECA and the Farm Bureau that California's agricultural sector is currently coping with steep reductions in water supplies which have in turn significantly increased agricultural electricity expenditures. For those with long memories, we began this decision with a discussion of the comments by farmers at our public witness hearings setting forth their dilemma. The farmers point out that this economic hardship is unique to the agricultural class in part because this increase in electric usage is a result of natural events and State water policies beyond their control. State conjunctive use policies depend on increased agricultural groundwater pumping during water-scarce periods so that scarce surface water supplies can be delivered to urban areas and used to benefit the environment.

Higher electricity costs disrupt farmers' ability to switch from surface to groundwater.

Secondly, since water and electricity uses are intimately tied in the agricultural community, water scarcity increases the variability in agricultural electrical use. AECA argues this makes it particularly difficult to forecast agricultural electricity usage on an annual basis. As a result, AECA believes that agricultural sales forecasts tend to over- or underestimate agricultural revenue responsibility in any given year. AECA concludes that this type of variation can lead to interclass subsidization.

While other parties do not dispute the hardships facing the agricultural class, which show no sign of abatement, no one is enthusiastic about AECA's proposed ERAM recommendation. AECA acknowledges that while that in particular it may not be the appropriate method, it does request very strongly that the

Commission develop some policy to address the effects of drought on their constituency.

AECA requests the Commission to develop some mechanism to address drought-related disruptions and to order PG&E to hold workshops to develop an appropriate mechanism and to address implementation issues. AECA urges that this be fully implemented if possible by the end of 1993.

We agree with AECA that all of its four points mentioned above deserve further consideration. It also seems to us that a better forum to address these concerns would be in a workshop format. Therefore, we will order CACD to hold workshops on the areas set forth by AECA. We are not endorsing an ERAM-type mechanism at this time. What we are endorsing is the principle that the agricultural class deserves some assistance from this Commission in dealing with the drought and we should try to mitigate the mixed signals it is receiving from State water agencies and this Commission vis-a-vis its electric rates. Unfortunately, it is likely the drought will continue into 1993. Therefore, we direct CACD to submit a report to the Commission in this docket by July 30, 1993 after workshops have been held.

## 29. Transcript Corrections

By letter dated July 17, 1992, PG&E requested certain corrections to the transcript. We accept these corrected changes. They will be made in the Commission's official transcript.

## 30. Comments on Proposed Decision

The ALJ's proposed decision was mailed on November 13, 1992. Opening comments were filed by the following parties on December 3, 1992: PG&E, DRA, AECA, CAL-SLA, CFBF, CLECA, IU, FEA, CEC, CEERT, NRDC, CSB, County of Lake, and TURN. A one-day extension was granted for the filing of reply comments. On December 9, 1992, the following parties submitted reply comments: DRA, PG&E, AECA, CFBF, CAL-SLA, CLECA, and TURN.

We have reviewed and carefully considered all the comments filed by the parties which did not merely reargue positions. We have made certain changes throughout the decision as appropriate.

31. TURN's Petition To Set Aside Submission

On November 19, 1992, TURN filed a Petition to Set Aside Submission of Phase 1 of this proceeding and reopen the case for the taking of additional evidence. TURN requests that the Commission take as a late-filed exhibit evidence that PG&E has instituted a hiring freeze of indeterminate length. TURN states that the freeze took effect on October 1, 1992, long after hearings were concluded. TURN argues that the hiring freeze constitutes a material change of fact and the financial impact of the hiring freeze will be unknown until PG&E is required to present evidence about the extent of the savings expected to result from the freeze. TURN believes PG&E's actions are similar to those that occurred in 1986, when shortly before a issuance of a GRC decision, PG&E announced layoffs and early retirements.

Therefore, TURN requests the Commission to reopen the proceeding to take additional evidence on the hiring freeze; direct PG&E to file a detailed description of the proposed hiring freeze, including the expected financial impact of such a freeze; and put PG&E on notice that a penalty may be assessed if the Commission ultimately finds that PG&E's actions constitute obstruction of the irate case process.

DRA joins TURN in its request to obtain further evidence on the financial impact of this hiring freeze.

On December 4, 1992, PG&E filed a timely response in opposition to TURN's position. PG&E argues that its hiring freeze is not a material change of fact because it is merely an interim measure, and its effect is only to increase management control of outside hiring. PG&E points out that while its interim hiring freeze may limit employee growth, this is only one aspect of overall costs examined by a GRC, and its effects may be offset by other factors, including employee turnover rates, outside services, nonlabor expense, or capital expenditures.

PG&E states the record in this proceeding is replete with discussions of PG&E's initiatives in restructuring and "right sizing," cost savings through a more productive work force, and labor productivity and the fact that each PG&E worker now handles more customers than previously.

In addition, PG&E points out that the proposed decision rejected increased staffing levels because of the assumed productivity and efficiency of PG&E's employees in most accounts where it was an issue.

Finally, PG&E argues that TURN and the Commission should applaud its cost-management efforts rather than complain about them. PG&E contends that the Commission has stated numerous times its desire not to engage in micromanagement or interference in utilities personnel policies. PG&E urges the Commission to deny TURN's petition and proceed with a final decision on all Phase 1 issues as scheduled by the Rate Case Plan.

We concur with PG&E that TURN's petition sets forth inadequate grounds for reopening what was a lengthy and thorough record on compensation and staffing levels for innumerable individual accounts. We disagree with TURN's characterization that the circumstances of this hiring freeze are the same as the program of layoffs and early retirements begun in 1986. We note that we have reduced overall compensation authorization from that which was proposed by the ALJ. We believe the record before us on compensation and staffing levels fully supports the decision we issue today. We construe PG&E's temporary hiring freeze as part of its ongoing cost-management in personnel practices in which we have no desire to micromanage.

Findings of Fact

1. PG&E's compensation strategy of paying slightly above market wage is worthy of further study.

2. Compensation surveys are subject to a 5% to 10% error rate, assuming the surveys are conductged properly in the first place. However, a 5% error rate is more likely for the type of surveys in which PG&E participated.

3. PG&E's pay at approximately 5% above market wage is reasonable given survey error rates, the size of the firm, the geographic location, the unionization, seniority and overall productivity of PG&E's workforce.

4. It is undeniable that PG&E has experienced substantial productivity gains in the past few years. It is undisputed that PG&E has laid off or reduced its work force by some 3,000 workers in the 1980s. It is also undisputed that each worker now handles more customers than previously. PG&E's productivity gains rate very favorably with national standards.

5. PG&E's total factor productivity modeling figures for productivity are reasonable.

6. Productivity gains are embedded in Test Year 1993 figures.

7. The primary difference between PG&E's and DRA's recommendations for labor escalation is the DRA zero escalation for labor as a noncompliance penalty for compliance with the last GRC decision.

8. The attrition year forecasts of the Consumer Price Index Workers (CPI-W) should be updated.

9. The agreed upon non-labor escalation factors are reasonable.

10. The only O&M expenses associated with nuclear production in this GRC are for the Humboldt Bay Unit 3 plant which is in the process of being decommissioned.

11. Prior to the final dismantlement and decontamination of the plant, O&M expenses will include the costs of monitoring and surveillance activities as well as maintenance of the security systems required by the Nuclear Regulatory Commission.

12. PG&E did not make an adequate showing that increasing expenses should be expected in the future for electric expenses in CPUC account 505.

13. Labor expenses will continue to decline for miscellaneous steam power expenses in CPUC account 506.

14. A more appropriate approach for structures is to base the expenses on a five-year average in CPUC account 511.

15. A certain portion of PG&E's asbestos mitigation program is appropriate to remove from boilers and related apparatus in CPUC account 512.2.

16. The five-year average gives a more accurate and realistic reflection of what boiler plant auxiliaries expenses will be in Test Year 1993 in CPUC account 512.3.

17. DRA's recommended disallowance for CPUC Account 512.4 regarding turbo blade replacement is reasonable.

18. The 1990 recorded expenses are more appropriate and accurate base for Test Year 1993 due to the declining trend that the main turbo-generator auxiliaries account has shown in CPUC account 513.5.

19. It is more appropriate to use 1990 recorded figures in order to capture the savings associated with the installation and operation of the OHMS in CPUC account 535.

20. It is more reasonable to include as one of the five years of experience a year, 1986, with heavy rainfall in various accounts that weather-dependent.

21. For hydraulic expenses, it is reasonable to use a five-year average to calculate labor and it is reasonable to use two workers instead of three for vegetation control.

22. The 1990 recorded expenses for labor more accurately forecast the expenses for electric expenses in 1993 by recognizing the declining trend since 1988 in CPUC account 538.

23. There is a declining trend in CPUC account 539 for miscellaneous hydraulic power generation expenses.

24. Our usual handling of accounts such as CPUC account 545.5 with such dramatic increases in a particular year is to average rather than take 1990 recorded year.

25. It is reasonable to use a five-year average as a base estimate for both labor and M&S expenses in the recreation facilities account CPUC account 548.5.

26. It is reasonable to use the two-year average to calculate base estimates for both labor and M&S to reflect the decline in the recorded expenses since 1989 in the miscellaneous other power generation account CPUC account 549.

27. It is reasonable to use 1990 recorded figures for supervision and engineering for both labor and M&S because CPUC account 551 has shown a declining trend.

28. The swings observed in operations supervision and engineering CPUC account 560 are best handled by use of a five-year average.

29. The way of supplying EMF information packets at the levels that have occurred in the past should not require the number of additional employees that PG&E seeks.

30. PG&E does not know what any given EMF reading actually means when done for the customer nor does the literature provide guidance on this point.

31. PG&E should be able to meet its increasing workload with four rather than seven additional positions in CPUC account 561.

32. It is reasonable to use the five-year average to calculate both the materials and services portion and the labor portion of the expenses for maintenance of station equipment in CPUC account.

33. It is reasonable to calculate the cost of tree trimming and the cost of tree removal together for the tree trimming account.

34. DRA's estimate of 6.25 positions is more than adequate to deal with EMF issues in CPUC account 580.

35. PG&E's supervisory control and data acquisition system (SCADA) provides supervisory controls of substation and gathers and displaying data about transformers, circuit loading, and voltage profiles.

36. Since SCADA is designed to save time and money, the most recent recorded year, 1990, best illustrates what will be needed for Test Year 1993.

37. The record is still unclear as to whether all distribution employees truly need to be trained in SCADA during Test Year 1993.

38. Only three additional workers are required to support strategic technology because of PG&E's inadequate showing.

39. The three-year average is more appropriate to reflect the substantial fluctuations occurring in CPUC account 591 for maintenance of structures.

40. A five-year average is reasonable to calculate the base estimate for labor and M&S expenses in CPUC account 593.62 for cleaning insulators and bushings.

41. It is reasonable to use a three-year average to reflect a declining trend in the labor expenses associated with CPUc account 593.65 for moving and relocating poles and guys.

42. It is reasonable to use a five-year average for base estimate of labor and a four-year average for base estimate of materials expenses in CPUC account 593.68 for reconditioning conductors.

43. In CPUC account 593.72 for overhead line maintenance, it is reasonable to use a three-year average to estimate labor expenses. As to M&S expenses, it is reasonable to use a five-year

average because it is unrealistic to exclude a nondrought year from the estimates.

44. The removal of drought-damaged trees will reduce tree trimming thereby offsetting the increase in tree removal costs.

45. PG&E has been using the system of competitive bidding for tree removal, resulting in decreasing costs.

46. It is reasonable to use a two-year average as a base estimate for both labor and M&S expenses in CPUC account 593.74.

47. The work schedule for maintenance of underground lines to be done in 1993 is in fact routine maintenance of underground distribution lines and therefore is properly charged to expense.

48. A five-year average for both labor and materials and supplies is more accurate because CPUC account 595 for line transformers tends to fluctuate substantially.

49. In CPUC account 593 for maintenance of overhead services, inclusion of 1986 with the following mild weather-drought years is appropriate for estimating Test Year 1993.

50. For maintenance of street lighting and signal systems, a three-year estimate is more appropriate for both labor and material and supplies due to the declining trend in recorded data.

51. It is reasonable to use 1990 recorded data for both labor and M&S estimates in order to reflect the declining trend in both portions of the maintenance of meters account.

52. It is reasonable to use 1990 recorded data for both labor and M&S estimates in order to reflect the declining trend in both portions of the miscellaneous distribution plant CPUc account 598.

53. PG&E's requested increases based on customer growth are unjustified given PG&E's expected productivity gains.

54. It is reasonable for PG&E to change its accounting procedures for conservation costs inquiries.

55. Additional dollars for the customer information computer program (CIS) rewrite are not necessary at this time.

56. There is already adequate money being spent regarding the customer payment option program.

57. The 13.52% allocation factor is the proper representation of the overall aggregate effect of the Use Study and is the appropriate factor to use when assigning 1990 base costs to Diablo Canyon.

58. PG&E has met its burden of proof in justifying its handling all Performance Incentive Plan (PIP) costs in various accounts.

59. PG&E and staff have agreed on PG&E's estimates for several accounts in the equal opportunity purchasing program.

60. It is appropriate to exclude a position for family benefits coordinator position for ratemaking purposes.

61. It is inappropriate to make an incentive pay adjustment based on 1989 data instead of basing an adjustment on specific 1990 base year data.

62. There is no plan in place to track an improvement in employee productivity because of the presence of a child care center, but a grant has been received from the Department of Labor.

63. Ratepayers are already providing an operational subsidy to the child care center by providing the space for the center at no rental fee within PG&E's headquarters building at 77 Beale Street in downtown San Francisco.

64. The allocation to construction credit represented by Account 922 should be developed by multiplying the total of Accounts 920 and 921 by a factor of 18.2%.

65. The actual case loads and work of PG&E's legal department cannot lead us to the conclusion that the proposed increase for outside legal services from 1990 levels is justified.

66. Funding of third-party litigation could lead to lower rates and should be allowed as a reasonable expense.

67. The direct benefit for maintaining investor lists is clearly with the shareholders and that any benefit that come to the

ratepayers is clearly two or three steps removed from the expenditure of the funds.

68. PG&E developed its medical cost escalation trend by separating the major components of cost, and escalating those components based on the best available data, including PG&E's specific experience.

69. Pre-funding of PBOPs expenses alleviates problems of intergenerational inequity, and is in the ratepayers' best long-term interest.

70. PG&E has until January 1, 1993 to demonstrate to CACD that its PBOP expense amounts incorporated into this GRC are in compliance with Ordering Paragraph 1 of D.92-12-015.

71. Diablo Canyon is in fact a regulated entity, not unregulated.

72. There has been no demonstrated need for a new training program called "Blueprint for Learning" separate for its on-going training that is a part of its day-to-day operations.

73. Current commitment line of credit fee contracts will expire in 1993 and the reluctance of banks to commit at this time to a definite rate suggests that they certainly will not entertain keeping the rate as it currently is.

74. In cost of service ratemaking, a legitimate cost of service must be included in rates.

75. It is reasonable to assign a 4.87% allocation factor of computer center expenses to Diablo Canyon using 1990 recorded use data to calculate use factors.

76. The property tax settlement described in Exhibit 220, including the resulting prospective reductions in property taxes and associated expenses for ratemaking purposes, as is the waiver of claims for any period before the May 1, 1992 effective date of the settlement, is reasonable and the terms of the settlement have been incorporated into the property tax related revenue determination for Test Year 1993 and attrition years 1994 and 1995.

77. Under cost of service ratemaking, it is reasonable and fair to allow PG&E to pass through increased sales tax voted in by the ratepayers of California.

78. PG&E and staff have agreed to comply with the capitalization of construction period interest and real property taxes resulting from the tax equity and fiscal responsibility act of 1982 (TEFRA) and a memorandum account was developed in response to that act.

79. It is reasonable to allow PG&E to request recovery of Geysers 21 costs in its next general rate case if the Commission does not approve the settlement in A.92-07-051.

80. If PG&E is successful in obtaining funds from the COT project participants, then an adjustment will be made to the ERAM balancing account at that time in order to flow any payments through to ratepayers.

81. PG&E has met our criteria for recovery of abandoned projects as has been set forth in prior Commission decisions.

82. Utility relicensing efforts prior to FERC approval are similar to construction work in progress, and should be treated as such for ratemaking purposes.

83. Seismic safety is of great concern and an important effort for PG&E to pursue.

84. The potential failure of the Echo Lake Dam could potentially cost PG&E's ratepayers many more millions of dollars than have been requested.

85. Language in our September Mokelumne settlement decision, D.92-9-022, clearly indicates that the ratepayers have been benefited by the settlement agreement.

86. For allocation purposes, it is reasonable to assume that the sale of PG&E's steam system will occur before January 1, 1993.

87. Since PIP is part of PG&E's overall total cash compensation program like other wage expenses, it is appropriate for inclusion in rate base.

88. The headquarter buildings of PG&E in San Francisco shoul be removed from rate base during their retrofit, but be allowed to accrue AFUDC and capitalzed property taxes for inclusion in ratebase when the retrofit is complete.

89. The savings promised in the PGE/MCI application are in fact mere cost avoidances.

90. M&S turnover is a better indicator of the effectiveness of M&S handling policies and procedures than the plant to M&S ratios.

91. The stipulated agreement on customer advances is reasonable.

92. The issues raised by Utility Design, Inc. are better heard in its complaint case or R.92-03-050.

93. The estimates of fossil plant decommissioning should be included in rates as reasonable estimates of costs required to provide service in a manner consistent with protection and enhancement of the environment of California.

94. PG&E's amount of nuclear decommissioning expenses for ratemaking purposes of $54,574,000, based on current cost estimates and consistent with the requirements of the Nuclear Facilities Decommissioning Act, is reasonable for the rate case cycle 1993 to 1995.

95. It is reasonable to continue the treatment approved in PG&E's last GRC of allowing revenues and costs associated with discounted sales to remain in the CPUC jurisdiction.

96. It is reasonable to use 1990 recorded costs for purchased gas measuring account CPUC account 807.2.

97. The gas restructuring program which we have instituted has increased the workload in certain areas of PG&E's Gas Department.

98. For other purchased gas accounts, it is reasonable to use 1990 recorded data to derive a base estimate for labor, and materials and services.

99. The failure of the levees around McDonald Island in 1982 led to the formation of a Reclamation District to undertake repairs to the levee system. Five property owners and PG&E make up the Reclamation District and PG&E currently holds one of the three seats on the Reclamation District's board of directors.

100. The McDonald Island levee repair work was the subject of testimony in PG&E's last general rate case in which PG&E's witness testified that the work should be completed by 1991.

101. In the last GRC, PG&E share of the assessments to the Reclamation District was 79%; in the 1990-91 fiscal year that share was increased to 95%. None of the other property owners on McDonald Island have, at any time since the project begin, contributed any cash to the assessment district. Instead, all the other participants have made their payments in "dirt."

102. Twice as much soil will have to be shifted as originally predicted, due in part to subsidence and in part to the nature of the soil being used.

103. The other property owners of the Reclamation District, who are only paying in dirt, should increase their share since the subsidence of the dirt has been one of the problems with the project.

104. PG&E's share of the McDonald Island levee repair work is unreasonable and not in the ratepayer's interest.

105. Given the changes that have occured due to industry restructuring, the workload must have increased for PG&E staff in the areas of system control and load dispatching.

106. It is important and necessary to move forward with the gas pipeline replacement program as quickly as possible.

107. PG&E has overcollected for the work it has performed relocating, replacing, and protecting meters.

108. It is reasonable to use a five-year average for both labor and materials expenses, given the fluctuations in CPUC account 880 for distribution maps and records.

109. The improved productivity that comes from the CIS rewrite should more than make up for the customer growth request in customer billing and accounting.

110. Membership in the American Gas Association is a legitimate cost of service which under a regulatory scheme should be a recoverable cost for PG&E.

111. The funding range for research, development and demonstration (RD&D) should be set at a range from 0.6% to 1.0% of gross operating revenues (GOR) for PG&E's 1996 GRC showing.

112. It is appropriate that each utility be dealt with consistently regarding shifting of funds in their RD&D programs.

113. It is only reasonable to fund Phase 1 and Phase 2 of the solar trough project because they are expected to be incurred in 1993 and 1994.

114. Wind turbine technology, based in part on prior research and development dollars, is now at a level of commercial viability that no longer needs the infusion of RD&D dollars by PG&E's ratepayers.

115. Ratepayer funds must not be used to promote research which favors utility services at the expense of the competitive market.

116. For the photovoltaics for utility scale applications, funding at a 30% level for Test Year 1993 is clearly a reasonable amount for one utility to be expected to fund.

117. PG&E's planned schedule for moving forward with smaller fuel cell research is overly optimistic.

118. It is unreasonable for PG&E to fund energy storage research at levels given that the technology has little prospect of being built by PG&E given the Commission's resource bidding process.

119. Funding for strategic studies should be reduced because ratepayers should not be funding an attempt to refine research

costs when it is actually the market which will determine which products are eventually built.

120. An additional increase in RD&D research at Geysers is not necessary in the context of PG&E's RD&D accounts.

121. This is the inappropriate form for issues involving customer system programs to be resolved.

122. For commercial energy efficiency, it is reasonable to use a funding level half-way between the funding average for 1990 through 1992 and the 1993 through 1995 requested amount.

123. Research into industrial systems is less likely to yield lessons applicable to a large number of other industrial customers.

124. For residential energy efficiency programs, the potential ratepayer benefits from additional utility RD&D expenses are uncertain.

125. PG&E's RD&D efforts in the areas of power quality, power electronics, and motors and systems are not leveraged with other organizations.

126. The Gas Cold Reactor Associates are more akin to an advocacy group than a research organization.

127. For clean air vehicles, it is inappropriate in this GRC to move forward at the pace which PG&E requests.

128. It is reasonable to defer significant increases in clean air vehicle funding until resolution of our low-emission vehicle investigation.

129. A Joint Recommendation on demand-side management issues has been submitted by DRA, PG&E, CMA, CLECA, and the California State Department of General Services (DGS).

130. The Joint Recommendation (Exhibit 214) is a reasonable compromise of the parties' positions and in the public interest.

131. The shared savings incentive mechanism as agreed to in the Joint Recommendation is fair, reasonable, and is in the best interest of PG&E's ratepayers.

132. It would be inappropriate for the CPUC to limit the refrigerator rebate program as requested by TURN.

133. The issue of further funding for TT&D programs has been adequately addressed by the Joint Recommendation.

134. Thermal energy storage should be treated as a "resource program" and DRA's recommended funding level is the most reasonable.

135. There is no reason at this time to continue the reporting requirements which we set up some time ago for conservation voltage reduction.

136. The Geysers 15 plant is retired and nonfunctional and therefore requires the Commission adopt ratemaking treatment of removing it from rate base.

137. Shareholders should only earn a return on used and useful plant.

138. Since Geysers 15 was not in operation, ratepayers should not pay for costs estimated to be associated with that plant because they were never incurred.

139. The steam offset payments were not a necessary part of the cost of obtaining steam to operate Unit 15.

140. The Lake County Wastewater Pipeline Project Proposal is the kind of public-private partnership that has every hope of preserving and enhancing the very valuable renewable resource of The Geysers.

141. PG&E is faced with NOx retrofit of several of its powerplants during this rate case cycle in order to comply with the California Clear Air Act.

142. The uncertainty of final NOx retrofit regulations makes it impossible for PG&E to fully develop the scope, cost, and schedule for various NOx reduction projects.

143. It is reasonable for PG&E to plan to schedule NOx retrofit projects during scheduled maintenance outages because it will save ratepayers money.

144. PG&E's proposed AQAC is a reasonable ratemaking mechanis: because the exact timing and final cost of these NOx retrofit projects can be forecasted at this time.

145. It is reasonable to review PG&E's NOx retrofit projects after the fact because PG&E carries the burden of proof that all costs were reasonably incurred.

146. The current attrition rate adjustment mechanism is working well, therefore, the changes proposed by PG&E and DRA are not appropriate.

147. Health care costs are escalating more rapidly than other costs.

148. It is reasonable to allow PG&E to attribute health care costs which it can identify separately in its A&G accounts as nonlabor costs for attrition purposes only in order to allow these expenses to receive some escalation.

149. PG&E does not need to make any changes to its accounting system other than that stipulated to with DRA.

150. PG&E's GRC was the appropriate forum for PG&E to propose changes to its current marginal cost methodology.

151. In adopting PG&E overall proposal, our goal is to continue to improve our marginal cost methodology in order to send the most accurate price signals to PG&E's customers.

152. It is reasonable that marginal cost components be based on the design and operation of PG&E's system, accurately signal the cost of providing electrical service, be forward-looking, capture the timing and magnitude of future investments, reflect geographic differences where significant, reflect the value that PG&E's customers place on electric service, only include those costs actually incurred by PG&E for revenue allocation purposes, and finally, provide consistent signals in the evaluation of supply and demand resources for planning purposes.

153. Our goal of more fairly and equitably allocating responsibility for PG&E's revenue requirement to the several customer classes is reasonable.

154. PG&E accurately characterizes its changes to its current marginal cost methodology as advancements.

155. PG&E's VOS approach for estimating marginal generation capacity costs is more economically efficient because it takes into account both supply and demand.

156. PG&E's proposal to compute separate bulk versus area marginal transmission costs is reasonable because this results in more accurate marginal costs by reflecting the differing causes of investment for each.

157. PG&E's proposal to take into account large transmission projects in certain geographic areas is reasonable.

158. It is reasonable for PG&E to estimate marginal distribution costs on a 13-division basis because it substantially increase accuracy, thus sending price signals which better reflect the differing costs customers cause PG&E to incur, and furthermore, provides the area-specific data necessary for future targeting of CEE programs.

159. It is reasonable to direct PG&E to refine its original proposal of breaking down its area study to the TPA and DPA levels in its next GRC because we endorse the concept that more disaggregated data yields better and more equitable marginal costs for different customer classes.

160. The present worth costing methodology is reasonable to use because it is the only method which estimates the opportunity cost of deferring transmission and distribution investments due to a change in load growth, taking into account both the timing and magnitude of such changes.

161. It is reasonable for PG&E to use regionally disaggregated marginal costs in order to reflect the different costs caused by new versus ongoing customers.

162. It is reasonable to exclude residual emission adders from marginal energy costs for purposes of revenue allocation in order to avoid bypass.

163. We are not suggesting by our adoption of PG&E's proposed changes that the current methodology may not be appropriate in other arenas, particularly LRMC for gas.

164. By bringing marginal costs down to a division-specific level, and adopting present worth and value of service methodologies, the agricultural class is much closer to its EPMC target than previously indicated.

165. The agricultural class is deserving of some special relief during drought years.

166. It is reasonable to convene workshops to explore mechanisms to assist the agricultural class in coping with the effects of the drought.

Conclusions of Law

1. The increase in rates authorized by this decision is just and reasonable and should be adopted.

2. We should conclude that PG&E has complied with the ordering paragraphs set forth in its last GRC decision at 34 CPUC2d 199, 438 et seq.

3. We should adopt the transcript corrections that have been submitted by PG&E.

4. PG&E should continue to use its TFP analysis.

5. PG&E should not be required to file an update to its Diablo Canyon Use Studies report until its Test Year 1999 GRC.

6. We should adopt all the adjustments made to PG&E's O&M expenses and A&G expenses set forth in this decision.

7. The ratepayers should not fund PG&E's child care center.

8. We should adopt PG&E's showing on total cash compensation.

9. We should require that PG&E's showing regarding PBOPs be consistent with our decisions in I.90-07-037, and to the extent that it is not, the related revenue requirement should be subject to refund as provided in this decision.

10. We should authorize PG&E to recover its nuclear decommissioning costs in rates pursuant to PU Code § 8321 et seq.

11. PG&E should be allowed to establish a funding range for RD&D programs of 0.6% to 1.0% in its next GRC.

12. We should adopt the Joint Recommendation on DSM issues because it is in the public interest as required by Rule 51 of our Rules of Practice and Procedure.

13. By following past Commission precedents, we should remove Geysers Unit 15 from rate base because it is no longer used and useful.

14. We should allow PG&E to establish an AQAC for NOx retrofit projects scheduled for 1994 and 1995 with mechanisms for recovery as set forth in the ordering paragraphs below.

15. We should adopt funding levels for CAV that allow a continuation of funding pending a decision in our investigation.

16. PG&E should be allowed to submit attrition filings in 1994 and 1995.

17. We should adopt the marginal costs set forth in the appendices attached to this decision.

18. We should convene workshops for the purposes set forth in the ordering paragraphs below.

## FIRST INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall, on or before December 23, 1992, file with this Commission revised tariff sheets which:

   a. Comply with the appendices attached to this decision.

   b. Make other revisions as necessary to comply with this interim order.

2. The revised tariff pages shall become effective January 1, 1993 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. All transcript corrections received are incorporated in the record.

4. PG&E is authorized to file attrition adjustments for 1994 and 1995 based on the results of operation adopted in these appendices.

5. PG&E shall continue to use the Total Factor Productivity analysis in its next general rate case (GRC).

6. PG&E shall update its report on its progress to rewrite its Customer Information System program in its next GRC.

7. PG&E shall not file a Diablo Canyon Use Studies report in its next GRC, rather a report is due in the Test Year 1999 rate case.

8. PG&E shall provide testimony in its next GRC on: (a) a combined wages, including incentive pay, and benefits analysis, with a particular focus on executive pay and benefits; (b) the link between its compensation strategy and productivity gains within the company; (c) the impact of our reduction of compensation levels for ratemaking purposes from 8.5% to 5% above market.

9. For its next GRC, PG&E shall provide to DRA the results of its various compensation surveys including, but not limited to, all applicable benchmarks and job matches, total employee cash contributions for benefit coverage as well as average bonus payments per employee.

10. PG&E shall provide a report on its progress in third-party litigation recovery for hazardous waste cleanup.

11. The decisions in Investigation 90-07-037 shall be controlling regarding post-retirement benefits other than pensions: (a) PG&E's showing in its next GRC shall be consistent with those

decision; (b) PG&E's PBOP revenue requirement incorporated into this GRC shall be subject to refund as provided in this decision.

12. PG&E shall report on the status of Geysers 21 in its next GRC and if necessary, may request recovery of Geysers 21 costs.

13. PG&E shall provide testimony in its next GRC on the costs of its seismic retrofitting of its 215 and 245 Market Street building for our consideration as to their reasonableness.

14. PG&E is authorized to include its nuclear decommissioning cost estimates in rates, subject to review and updating in its next GRC.

15. PG&E shall provide testimony in its next GRC on the status of its Gas Pipeline Replacement Program particularly as to whether spending occurred at levels authorized for this rate case cycle.

16. PG&E is authorized to set a funding range of 0.6% to 1.0% for research, development, and demonstration (RD&D) programs for its next GRC showing.

17. PG&E is authorized to shift RD&D program funding by 20% without further Commission, 20% to 50% if the Commission grants an advice letter request, and above 50% if the Commission grants a request by application.

18. PG&E is authorized to implement the agreements set forth in the Joint Recommendation on demand-side management issues.

19. PG&E shall remove $30.2 million from rate base to reflect Geysers Unit 15 retirement.

20. PG&E shall refund the Geysers Unit 15 memorandum account, approximately $36 million, to ratepayers over the next 5 years.

21. PG&E shall be allowed to recover the Geysers Unit 15 steam offset payments, $5,028,865, from its subaccount of the Energy Cost Adjustment Clause balancing account.

22. PG&E is authorized to seek recovery of up to $2 million in its 1994 and 1995 attrition filings for the southeast Geysers effluent pipeline project.

23. PG&E shall report, in its next GRC filing, on the status of the southeast Geysers effluent pipeline project.

24. PG&E is authorized to set up its air quality adjustment clause (AQAC) to begin recording revenue requirement, including maintenance and operating expenses, for each of its NOx retrofit projects tentatively scheduled for 1994 and 1995.

25. Interim rates for each operative NOx retrofit project shall be implemented through advice letter filings concurrent with the annual attrition rate adjustment mechanism subject to later reasonableness review.

26. For NOx retrofit projects over $50 million, PG&E shall file an application for reasonableness review of the recorded costs of the project as accumulated in the AQAC.

27. For NOx retrofit projects under $50 million, PG&E shall provide a report in its next GRC filing.

28. PG&E shall submit a cost-effectiveness compliance filing 6 months prior to the start of the NOx retrofit project in this docket with comments by other parties 45 days after.

29. PG&E is authorized to include in its 1994 and 1995 attrition filings separately identifiable administrative and general health care costs in the nonlabor costs category for attrition purposes only.

30. PG&E shall make the changes to its accounting system in the areas where PG&E reached agreement with Division of Ratepayer Advocates.

31. PG&E is authorized to implement its proposed methodological changes to marginal cost and revenue allocation as set forth in this decision.

32. The Commission Advisory and Compliance Division shall conclude workshops by July 30, 1993, submit a report in the Docket Office by September 1, 1993 addressing the following issues:

a. Tracking mechanisms to capture the results of the use of the methodological changes approved in this decision.

b. Approaches for further disaggregation of data for area specific marginal cost development in the next GRC that allows for intervenor participation without undue burden.

c. Mechanisms to address drought-related disruption faced by the agricultural community, including, but not limited to, improving agricultural sales forecasts and developing drought-related standby rates.

This order is effective today.

Dated December 16, 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

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List of Appearances

Applicants: Kermit Kubitz, Robert McLennan, and Gail Slocum, Attorneys at Law, for Pacific Gas and Electric Company; and John D. Quinley, for Cogeneration Service Bureau.

Interested Parties: Barbara R. Barkovich, for Barkovich & Yap; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Messrs. Morrison & Foerster, by Lynn Haug and Jerry Bloom, Attorneys at Law, for California Cogeneration Council; Michael Boccadoro, for Agricultural Energy Consumers; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Evelyn Elsesser, for California Large Energy Consumers Association; Thomas R. Brill, Attorney at Law, for Southern California Gas Company; Maurice Brubaker, for Drazen-Brubaker & Associates; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for the California City-County Street Light Association; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Tom Dalzell, Attorney at Law, for Local 1245, IBEW; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam De Frawi, for the Department of the Navy; Mark Dellinger, for the County of Lake; Marc Estrada, for City of Palo Alto; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Marco Gomez, for Bay Area Rapid Transit District; Messrs. Skadden, Arps, Slate, Meagher & Flom, by Steven F. Greenwald, Attorney at Law, for various clients; Messrs. Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services; Messrs. Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilehome Association; Messrs. Graham & James, by Peter W. Hanschen, Attorney at Law, for Agricultural Energy Consumers Association; Steve Harris by Lisa Danyluk, for Transwestern Pipeline; Phyllis Huckabee and Phillip D. Endom, for El Paso Natural Gas Company; Yvonne Ladson, for Los Angeles Department of Water and Power; Donald H. Maynor, Attorney at Law, for Northern California Power Agency; Patrick McGuire, for Sierra Energy and Risk Assessment, Inc.; Melissa Metzler, for Barakat & Chamberlin; Joseph G. Meyer, for Joseph Meyer Associates; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Julie Miller, Attorney at Law, for Southern California Edison Company; Jeff Nahigian, for JBS Energy; Thomas J. O'Rourke, for O'Rourke & Company; Patrick Power, Attorney at Law, for Sacramento

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Municipal Utility District; Roger L. Poynts, for Utility Design, Inc.; Justin K. Reidhead and Michel Peter Florio, Attorneys at Law, for Toward Utility Rate Normalization; Donald G. Salow, for the Association of California Water Agencies; Lee Shavrien and C. Richard Swanson, for San Diego Gas & Electric Company; Reed V. Schmidt, for Main Street Light Authority; Victoria Simmons, for Edson & Modisette; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for Industrial Users; John C. Walley, Attorney at Law, for Southwest Gas Corporation; Morse, Richard, Weisenmiller & Associates, by Robert B. Weisenmiller, for MRW & Associates; Ron Knecht, for the Economic & Technical Analysis Group; and Sesto F. Lucchi, for himself.

Division of Ratepayer Advocates: Robert Cagen and Laura Tudisco, Attorneys at Law, and B. Y. Lee.

(END OF APPENDIX A)

# APPENDIX B - ELECTRIC DEPARTMENT'S RESULTS OF OPERATIONS
## PACIFIC GAS AND ELECTRIC COMPANY
## Electric Department, Test Year 1993

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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department

JANUARY 1, 1993 CONSOLIDATED REVENUE CHANGES
($000)

| LINE NO. | DESCRIPTION | PRESENT RATE REVENUE (A) | REVENUE CHANGE (B) | ADOPTED REVENUE REQUIREMENT (C) (c) | | AVERAGE RATE (cents/kWh) (D) (d) |
|---|---|---|---|---|---|---|
| 1 | ENERGY COST ADJUSTMENT CLAUSE (ECAC) | | | | | |
| 2 | Authorized ECAC Costs | | | 3,495,091 | | |
| 3 | Estimated 12/31/92 ECAC Account Balance | | | (6,554) | | |
| 4 | Diablo Canyon Safety Committee Fee | | | 716 | | |
| 5 | Designated Sales Transactions to Resale Customers | | | (41,479) | | |
| 6 | Franchise Fees & Uncollectibles at 0.85% | | | 29,306 | | |
| 7 | | | | ........... | | |
| 8 | Total ECAC Revenue Requirement without Geysers 15 | 3,644,977 | (167,897) | 3,477,080 | | |
| 9 | GEYSERS 15 STEAM OFFSET RECOVERY (one-time adjustment) | 0 | 0 | 0 | (a) | |
| 10 | Total ECAC-Related Revenue Requirement | 3,644,977 | | 3,477,080 | | 4.90 |
| 11 | | | | | | |
| 12 | ANNUAL ENERGY RATE (AER) | | | | | |
| 13 | Adopted AER Costs | | | 196,505 | | |
| 14 | Designated Sales Transactions to Resale Customers | | | (4,102) | | |
| 15 | Franchise Fees & Uncollectibles at 0.85% | | | 1,635 | | |
| 16 | | | | ........... | | |
| 17 | Total AER Revenue | 203,664 | (9,626) | 194,038 | | 0.27 |
| 18 | | | | | | |
| 19 | BASE ENERGY REVENUE REQUIREMENT | | | | | |
| 20 | Authorized Base Revenue Amount for 1993 | | | | | |
| 21 | GRC RESULTS OF OPERATIONS | | | 3,753,557 | (a) | |
| 22 | OTHER OPERATING REVENUE | | | (43,334) | | |
| 23 | TEFRA AMORTIZATION (1st of 6 yrs) | | | 2,955 | (a) | |
| 24 | GEYSERS 15: MEMORANDUM ACCOUNT AMORTIZATION (1st of 5 yrs) | | | (7,694) | (a) | |
| 25 | Diablo Canyon Base Revenue | | | 185,096 | (b) | |
| 26 | | | | | | |
| 27 | Estimated 12/31/92 ERAA Balance | | | 152,096 | | |
| 28 | LIRA Shortfall | | | (29,118) | | |
| 29 | Designated Sales Transactions to Resale Customers | | | (54,417) | | |
| 30 | | | | ........... | | |
| 31 | Total ERAM Retail Revenues | 3,550,524 | 408,617 | 3,959,141 | | 5.58 |
| 32 | | | | | | |
| 33 | LOW INCOME RATE ASSISTANCE (LIRA) | | | | | |
| 34 | LIRA Shortfall | | | 29,118 | | |
| 35 | Estimated 12/31/92 LIRA Account Balance | | | (838) | | |
| 36 | LIRA Administrative Costs | | | 0 | | |
| 37 | | | | ........... | | |
| 38 | Total LIRA Revenue Requirement | 18,515 | 9,765 | 28,280 | | 0.04 |
| 39 | | | | | | |
| 40 | CEE and OTHER REVENUE REQUIREMENT | | | | | |
| 41 | One-third of 1990 and 1991 Shareholder Incentive | | | 16,221 | | |
| 42 | Estimated 12/31/92 CEEIA Interest Balance | | | 1,441 | | |
| 43 | Franchise Fees & Uncollectibles at 0.85% | | | 150 | | |
| 44 | | | | ........... | | |
| 45 | Total CEE Revenue Requirement | 4,256 | 13,556 | 17,812 | | 0.03 |
| 46 | | | | | | |
| 47 | Conservation Financing Adjustment | 1,444 | 0 | 1,444 | | |
| 48 | California Public Utilities Commission Fees | 8,552 | 0 | 8,552 | | |
| 49 | | ............. | | ........... | | |
| 50 | TOTAL RETAIL REVENUES FOR RATE CONSTRUCTION | 7,431,932 | 254,415 | 7,686,347 | | 10.84 |
| 51 | | ============= | | =========== | | |
| 52 | OTHER REVENUES | 43,334 | | 43,334 | | |
| 53 | TOTAL ELECTRIC DEPARTMENT REVENUE REQUIREMENT | | | 7,729,681 | | |
| 54 | | | | | | |
| 55 | Consolidated Percent Increase Over Retail Revenues at Present Rates | | 3.42% | | | |

NOTES:
(a) Adopted in this decision.
(b) Reflects 1993 Diablo Canyon weighted average rate base and adopted 1993 cost of capital.
(c) Includes adopted revenue requirement in PG&E's ECAC D.92-11-046.
(d) Average rate is calculated using adopted retail sales forecast of 70,926 GWh.

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

SUMMARY OF EARNINGS, COMPARISON
(Thousands of 1993 dollars)

| Line No. | Description | CPUC JURISDICTION PG&E | DRA | ADOPTED |
|---|---|---|---|---|
| | | (A) | (B) | (C) |
| | Operating Revenues | | | |
| 1 | GRC Revenues at Present Rates | 3,465,352 | 3,465,352 | 3,465,352 |
| 2 | GRC Revenue Change | 405,101 | 129,278 | 288,205 |
| 3 | Total GRC Revenues | 3,870,453 | 3,594,630 | 3,753,557 |
| | Operating Expenses | | | |
| 4 | Energy Cost | 85 | 85 | 85 |
| 5 | Production | 288,965 | 264,765 | 265,444 |
| 6 | Transmission | 59,011 | 57,157 | 57,157 |
| 7 | Distribution | 254,566 | 243,060 | 247,460 |
| 8 | Customer Accounts | 117,913 | 115,189 | 111,354 |
| 9 | Uncollectibles | 11,792 | 10,954 | 11,430 |
| 10 | Demand-Side Management | 202,445 | 195,530 | 196,752 |
| 11 | Administrative & General | 497,674 | 431,338 | 454,583 |
| 12 | Franchise Requirements | 24,779 | 22,991 | 24,008 |
| 13 | Project Amortization | 7,465 | 7,465 | 7,465 |
| 14 | Adjustments | 0 | 0 | 0 |
| 15 | Subtotal, 1990 Dollars | 1,464,695 | 1,348,535 | 1,375,738 |
| 16 | Labor Adjustment To Parity | 0 | (37,461) | (15,175) |
| 17 | Labor Escalation | 75,092 | 0 | 71,785 |
| 18 | Non-Labor Escalation (incl. medical) | 81,710 | 56,570 | 76,223 |
| 19 | Subtotal, 1993 Dollars | 1,621,497 | 1,367,644 | 1,508,571 |
| 20 | Superfund Tax Increase | 450 | 154 | 343 |
| 21 | Depreciation & Fossil Decommission. | 643,054 | 647,018 | 648,416 |
| 22 | Nuclear Decommissioning Expense | 54,119 | 54,119 | 54,119 |
| 23 | Taxes Other Than On Income | 172,417 | 158,915 | 166,582 |
| 24 | California Corporate Franchise Tax | 95,261 | 95,132 | 95,679 |
| 25 | Federal Income Tax | 354,431 | 353,834 | 355,941 |
| 26 | Total Operating Expenses | 2,941,229 | 2,676,817 | 2,829,650 |
| 27 | Net Operating Revenues | 929,224 | 917,813 | 923,908 |
| 28 | Return on Rate Base | 929,224 | 917,813 | 923,908 |
| 29 | Adjusted Rate Base | 9,172,993 | 9,060,343 | 9,120,510 |
| 30 | Rate of Return | 10.13% | 10.13% | 10.13% |

NOTE: For comparison purposes, columns A and B have been recalculated by CACD staff to reflect adopted 1993 cost of capital.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

SUMMARY OF EARNINGS, TOTAL SYSTEM AND CPUC JURISDICTION
(Thousands of 1993 dollars)

| Line No. | Description | Total | CPUC Jurisdiction |
|---|---|---|---|
| | | (A) | (B) |
| | Operating Revenues | | |
| 1 | GRC Revenues at Present Rates | $3,533,779 | $3,465,352 |
| 2 | GRC Revenue Change | 284,451 | 288,205 |
| 3 | Total GRC Revenues | 3,818,230 | 3,753,557 |
| | Operating Expenses | | |
| 4 | Energy Cost | 2,058 | 85 |
| 5 | Production | 266,853 | 265,444 |
| 6 | Transmission | 63,463 | 57,157 |
| 7 | Distribution | 249,512 | 247,460 |
| 8 | Customer Accounts | 111,496 | 111,354 |
| 9 | Uncollectibles | 11,418 | 11,430 |
| 10 | Demand-Side Management | 196,752 | 196,752 |
| 11 | Administrative & General | 460,913 | 454,583 |
| 12 | Franchise Requirements | 24,399 | 24,008 |
| 13 | Project Amortization | 7,729 | 7,465 |
| 14 | Adjustments | 0 | 0 |
| 15 | Subtotal, 1990 Dollars | 1,394,593 | 1,375,738 |
| 16 | Labor Adjustment To Parity | (15,385) | (15,175) |
| 17 | Labor Escalation | 72,784 | 71,785 |
| 18 | Non-Labor Escalation (incl. medical) | 77,089 | 76,223 |
| 19 | Subtotal, 1993 Dollars | 1,529,081 | 1,508,571 |
| 20 | Superfund Tax Increase | 338 | 343 |
| 21 | Depreciation & Fossil Decommission. | 660,185 | 648,416 |
| 22 | Nuclear Decommissioning Expense | 54,474 | 54,119 |
| 23 | Taxes Other Than On Income | 169,667 | 166,582 |
| 24 | California Corporate Franchise Tax | 97,678 | 95,679 |
| 25 | Federal Income Tax | 362,998 | 355,941 |
| 26 | Total Operating Expenses | 2,874,421 | 2,829,650 |
| 27 | Net Operating Revenues | 943,810 | 923,908 |
| 28 | Return on Rate Base | 943,810 | 923,908 |
| 29 | Adjusted Rate Base | 9,316,976 | 9,120,510 |
| 30 | Rate of Return | 10.13% | 10.13% |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

FRANCHISE FEES & UNCOLLECTIBLES
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | AT ADOPTED RATES | |
| 1 | General Rate Case Revenues | $3,818,230 |
| 2 | Percent of Revenues From Customers | 99.79% |
| 3 | Revenues From Customers | 3,810,212 |
| 4 | Steam Department Adjustment | 99.89% |
| 5 | Uncollectible Factor | 0.3000% |
| 6 | Uncollectibles | 11,418 |
| 7 | Revenues From Customers | 3,810,212 |
| 8 | Steam Department Adjustment | 99.89% |
| 9 | Uncollectibles | (11,418) |
| 10 | Net Revenues From Customers | 3,794,603 |
| 11 | Franchise Requirement Factor | 0.6430% |
| 12 | Franchise Requirements | 24,399 |
| 13 | Franchise Amortization | 0 |
| 14 | Total Franchise Requirements | 24,399 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | TOTAL NON-ESCALATED (1990$) | |
| 1 | Energy Costs | $2,058 |
| 2 | Steam Production | 173,503 |
| 3 | Nuclear Production | 1,256 |
| 4 | Hydraulic Production | 47,610 |
| 5 | Other Production | 44,484 |
| 6 | Total Production (lines 2 through 5) | 266,853 |
| 7 | Transmission | 63,463 |
| 8 | Distribution | 249,512 |
| 9 | Customer Accounts | 122,063 |
| 10 | Demand-Side Management | 196,752 |
| 11 | Administrative and General | 483,494 |
| 12 | Total Non-Escalated (1990$) | 1,384,195 |
| | TOTAL ESCALATED (1993$): | |
| 13 | Energy Costs | 2,058 |
| 14 | Steam Production | 194,137 |
| 15 | Nuclear Production | 1,412 |
| 16 | Hydraulic Production | 53,264 |
| 17 | Other Production | 46,629 |
| 18 | Total Production (lines 14 through 17) | 295,442 |
| 19 | Transmission | 71,359 |
| 20 | Distribution | 280,404 |
| 21 | Customer Accounts | 135,626 |
| 22 | Demand-Side Management | 217,813 |
| 23 | Administrative and General | 531,366 |
| 24 | Total Escalated (1993$) | 1,534,068 |
| | TOTAL ESCALATION (1990$ to 1993$): | |
| 25 | Energy Costs | 0 |
| 26 | Steam Production | 20,634 |
| 27 | Nuclear Production | 156 |
| 28 | Hydraulic Production | 5,654 |
| 29 | Other Production | 2,145 |
| 30 | Total Production (lines 26 through 30) | 28,589 |
| 31 | Transmission | 7,896 |
| 32 | Distribution | 30,892 |
| 33 | Customer Accounts | 13,563 |
| 34 | Demand-Side Management | 21,061 |
| 35 | Administrative and General | 47,872 |
| 36 | Total Escalation | 149,873 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

LABOR EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | LABOR NON-ESCALATED (1990$) | |
| 1 | Steam Production | $75,019 |
| 2 | Nuclear Production | 688 |
| 3 | Hydraulic Production | 23,729 |
| 4 | Other Production | 7,931 |
| 5 | Total Production (lines 1 through 4) | 107,367 |
| 6 | Transmission | 35,380 |
| 7 | Distribution | 135,579 |
| 8 | Customer Accounts | 75,585 |
| 9 | Demand-Side Management | 31,949 |
| 10 | Administrative and General | 94,923 |
| 11 | Total Non-Escalated Labor | 480,783 |
| 12 | Non-Escalated Wage-Related A&G | 25,017 |
| 13 | Total | 505,800 |
| 14 | Parity Adjustment | (15,385) |
| 15 | Labor Escalation Factor | 1.1439 |
| | LABOR ESCALATED (1993$) | |
| 16 | Steam Production | 85,814 |
| 17 | Nuclear Production | 787 |
| 18 | Hydraulic Production | 27,144 |
| 19 | Other Production | 9,072 |
| 20 | Total Production (lines 16 through 19) | 122,817 |
| 21 | Transmission | 40,471 |
| 22 | Distribution | 155,089 |
| 23 | Customer Accounts | 86,462 |
| 24 | Demand-Side Management | 36,546 |
| 25 | Administrative and General | 108,582 |
| 26 | Total Escalated Labor | 549,967 |
| 27 | Escalated Wage-Related A&G | 28,617 |
| 28 | Total Escalated Labor | 578,584 |
| | LABOR ESCALATION (1990$ to 1993$) | |
| 29 | Steam Production | 10,795 |
| 30 | Nuclear Production | 99 |
| 31 | Hydraulic Production | 3,415 |
| 32 | Other Production | 1,141 |
| 33 | Total Production (lines 29 through 32) | 15,450 |
| 34 | Transmission | 5,091 |
| 35 | Distribution | 19,510 |
| 36 | Customer Accounts | 10,877 |
| 37 | Demand-Side Management | 4,597 |
| 38 | Administrative and General | 13,659 |
| 39 | Total Labor Escalation | 69,184 |
| 40 | Wage-Related A&G Escalation | 3,600 |
| 41 | Total Labor & Wage-Related Escalation | 72,784 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

NON-LABOR EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | NON-LABOR NON-ESCALATED (1990$) | |
| 1 | Steam Production | $98,484 |
| 2 | Nuclear Production | 568 |
| 3 | Hydraulic Production | 22,412 |
| 4 | Other Production | 10,051 |
| 5 | Total Production (lines 1 through 4) | 131,515 |
| 6 | Transmission | 28,083 |
| 7 | Distribution | 113,933 |
| 8 | Customer Accounts | 26,891 |
| 9 | Demand-Side Management | 164,803 |
| 10 | Administrative and General | 124,336 |
| 11 | Total Non-Escalated Non-Labor | 589,561 |
| 12 | Non-Labor Escalation Factor | 1.0999 |
| | NON-LABOR ESCALATED (1993$) | |
| 13 | Steam Production | 108,323 |
| 14 | Nuclear Production | 625 |
| 15 | Hydraulic Production | 24,651 |
| 16 | Other Production | 11,055 |
| 17 | Total Production (lines 13 through 16) | 144,654 |
| 18 | Transmission | 30,888 |
| 19 | Distribution | 125,315 |
| 20 | Customer Accounts | 29,577 |
| 21 | Demand-Side Management | 181,267 |
| 22 | Administrative and General | 136,757 |
| 23 | Total Escalated Non-Labor | 648,458 |
| | NON-LABOR ESCALATION (1990$ to 1993$) | |
| 24 | Steam Production | 9,839 |
| 25 | Nuclear Production | 57 |
| 26 | Hydraulic Production | 2,239 |
| 27 | Other Production | 1,004 |
| 28 | Total Production (lines 24 through 27) | 13,139 |
| 29 | Transmission | 2,805 |
| 30 | Distribution | 11,382 |
| 31 | Customer Accounts | 2,686 |
| 32 | Demand-Side Management | 16,464 |
| 33 | Administrative and General | 12,421 |
| 34 | Total Non-Labor Escalation | 58,897 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

OTHER EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | OTHER NON-ESCALATED (1990$) | |
| 1 | Energy Costs | $2,058 |
| 2 | Steam Production | 0 |
| 3 | Nuclear Production | 0 |
| 4 | Hydraulic Production | 1,469 |
| 5 | Other Production | 26,502 |
| 6 | Total Production (lines 2 through 5) | 27,971 |
| 7 | Transmission | 0 |
| 8 | Distribution | 0 |
| 9 | Customer Accounts | 19,587 |
| 10 | Demand-Side Management | 0 |
| 11 | Administrative and General | 239,218 |
| 12 | Total Non-Escalated Other | 288,834 |
| 13 | Medical Escalation Factor | 1.4095 |
| 14 | Other Escalation Factor | 1.0000 |
| | OTHER ESCALATED (1993$) | |
| 15 | Energy Costs | 2,058 |
| 16 | Steam Production | 0 |
| 17 | Nuclear Production | 0 |
| 18 | Hydraulic Production | 1,469 |
| 19 | Other Production | 26,502 |
| 20 | Total Production (lines 16 through 19) | 27,971 |
| 21 | Transmission | 0 |
| 22 | Distribution | 0 |
| 23 | Customer Accounts | 19,587 |
| 24 | Demand-Side Management | 0 |
| 25 | Administrative and General | 257,410 |
| 26 | Total Escalated Other | 307,026 |
| | OTHER (and Medical) ESCALATION | |
| 27 | Energy Costs | 0 |
| 28 | Steam Production | 0 |
| 29 | Nuclear Production | 0 |
| 30 | Hydraulic Production | 0 |
| 31 | Other Production | 0 |
| 32 | Total Production (lines 28 through 32) | 0 |
| 33 | Transmission | 0 |
| 34 | Distribution | 0 |
| 35 | Customer Accounts | 0 |
| 36 | Demand-Side Management | 0 |
| 37 | Administrative and General | 18,192 |
| 38 | Total Other (and Medical) Escalation | 18,192 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

STEAM PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 500.0 | Supervision and Engineering | $8,504 |
| 2 | 501.0 | Fuel - Other Expenses | 1,797 |
| 3 | 502.0 | Steam Expenses | 13,675 |
| 4 | 505.0 | Electric Expenses | 25,956 |
| 5 | 506.0 | Misc. Steam Power Expenses | 24,059 |
| 6 | 507.0 | Rents | 1,978 |
| 7 | | Total Operation | 75,969 |
| | | Maintenance | |
| 8 | 510.0 | Supervision and Engineering | 9,766 |
| 9 | 511.0 | Structures | 1,154 |
| 10 | 512.2 | Boilers and Related Apparatus | 21,681 |
| 11 | 512.3 | Boiler Plant Auxiliaries | 13,316 |
| 12 | 513.4 | Main Turbos & Related Apparatus | 27,631 |
| 13 | 513.5 | Main Turbo Auxiliaries | 13,259 |
| 14 | 513.6 | Accessory Electric Equipment | 3,804 |
| 15 | 514.0 | Miscellaneous Steam Plant | 6,923 |
| 16 | | Total Maintenance | 97,534 |
| 16a | | Steam Department Adjustment | 0 |
| 17 | | TOTAL STEAM PRODUCTION (1990$) | 173,503 |
| | | Escalation Amounts, 1990 to 1993 | |
| 18 | | Labor | 10,795 |
| 19 | | Non-Labor | 9,839 |
| 20 | | Other | 0 |
| 21 | | Total Escalation | 20,634 |
| 22 | | TOTAL STEAM PRODUCTION (1993$) | 194,137 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

NUCLEAR PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 517.0 | Supervision and Engineering | $355 |
| 2 | 519.0 | Coolants and Water | 19 |
| 3 | 520.0 | Steam Expenses | 206 |
| 4 | 523.0 | Electric Expenses | 65 |
| 5 | 524.0 | Miscellaneous Nuclear Power Expenses | 495 |
| 6 | | Total Operation | 1,140 |
| | | Maintenance | |
| 7 | 528.0 | Supervision and Engineering | 10 |
| 8 | 529.0 | Structures | 46 |
| 9 | 530.2 | Reactor and Related Apparatus | 0 |
| 10 | 530.4 | Reactor Plant Auxiliaries | 41 |
| 11 | 531.4 | Main Turbos & Rel. Apparatus | 9 |
| 12 | 531.5 | Main Turbo Auxiliaries | 1 |
| 13 | 531.6 | Accessory Electric Equipment | 7 |
| 14 | 532.0 | Miscellaneous Nuclear Plant | 2 |
| 15 | | Total Maintenance | 116 |
| 16 | | TOTAL NUCLEAR PRODUCTION (1990$) | 1,256 |
| | | Escalation Amounts, 1990 to 1993 | |
| 17 | | Labor | 99 |
| 18 | | Non-Labor | 57 |
| 19 | | Other | 0 |
| 20 | | Total Escalation | 156 |
| 21 | | TOTAL NUCLEAR PRODUDCTION (1993$) | 1,412 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

HYDRAULIC PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 535.0 | Supervision and Engineering | $1,750 |
| 2 | 536.0 | Water for Power | 3,356 |
| 3 | 537.1 | Hydraulic Expenses | 3,561 |
| 4 | 537.2 | Fish and Wildlife Expenses | 52 |
| 5 | 537.3 | Recreation Expenses | 629 |
| 6 | 538.0 | Electric Expenses | 5,668 |
| 7 | 539.0 | Miscellaneous Hydro Expense Generation | 4,687 |
| 8 | 540.0 | Rents | 4,651 |
| 9 | | Total Operation | 24,354 |
| | | Maintenance | |
| 10 | 541.0 | Supervision and Engineering | 4,601 |
| 11 | 542.0 | Structures | 455 |
| 12 | 543.0 | Reservoirs, Dams and Waterways | 8,540 |
| 13 | 544.3 | Prime Movers and Generators | 4,920 |
| 14 | 544.4 | Accessory Electric Equipment | 2,343 |
| 15 | 545.5 | Miscellaneous Hydraulic Plant | 655 |
| 16 | 545.6 | Roads, Railroads and Bridges | 1,444 |
| 17 | 545.7 | Fish and Wildlife Facilities | 163 |
| 18 | 545.8 | Recreation Facilities | 135 |
| 19 | | Total Maintenance | 23,256 |
| 20 | | TOTAL HYDRO PRODUCTION (1990$) | 47,610 |
| | | Escalation Amounts, 1990 to 1993 | |
| 21 | | Labor | 3,415 |
| 22 | | Non-Labor | 2,239 |
| 23 | | Other | 0 |
| 24 | | Total Escalation | 5,654 |
| 25 | | TOTAL HYDRO PRODUCTION (1993$) | 53,264 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

OTHER POWER PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 546.0 | Supervision and Engineering | $49 |
| 2 | 548.0 | Generation Expenses | 507 |
| 3 | 549.0 | Miscellaneous Other Power Expenses | 230 |
| 4 | 555.0 | Purchased Power-Other Power Supplies | 42,826 |
| 5 | | Total Operation | 43,612 |
| | | Maintenance | |
| 6 | 551.0 | Supervision and Engineering | 131 |
| 7 | 552.0 | Maintenance of Structures | 5 |
| 8 | 553.0 | Maintenance of Electric Plant | 322 |
| 9 | 554.0 | Miscell. Other Power General Plant | 414 |
| 10 | | Total Maintenance | 872 |
| 11 | | TOTAL OTHER POWER PRODUCTION (1990$) | 44,484 |
| | | Escalation Amounts, 1990 to 1993 | |
| 12 | | Labor | 1,141 |
| 13 | | Non-Labor | 1,004 |
| 14 | | Other | 0 |
| 15 | | Total Escalation | 2,145 |
| 16 | | TOTAL OTHER POWER PRODUCTION (1993$) | 46,629 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

TOTAL PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Operation | |
| 1 | Steam | $75,969 |
| 1a | Steam Department Adjustment | 0 |
| 2 | Nuclear | 1,140 |
| 3 | Hydraulic | 24,354 |
| 4 | Other | 43,612 |
| 5 | Total Operation | 145,075 |
| | Maintenance | |
| 6 | Steam | 97,534 |
| 6a | Steam Department Adjustment | 0 |
| 7 | Nuclear | 116 |
| 8 | Hydraulic | 23,256 |
| 9 | Other | 872 |
| 10 | Total Maintenance | 121,778 |
| 11 | TOTAL PRODUCTION (1990$) | 266,853 |
| | Escalation Amounts, 1990 to 1993 | |
| 12 | Labor | 15,450 |
| 13 | Non-Labor | 13,138 |
| 14 | Other | 0 |
| 15 | Total Escalation | 28,588 |
| 16 | TOTAL PRODUCTION (1993$) | 295,441 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

TRANSMISSION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 560.0 | Supervision and Engineering | $3,310 |
| 2 | 561.0 | Load Dispatching | 7,017 |
| 3 | 562.0 | Station Expenses | 9,761 |
| 4 | 563.0 | Overhead Line Expenses | 3,685 |
| 5 | 564.0 | Underground Line Expenses | 147 |
| 6 | 565.0 | Transmission of Electricity By Others | 7,346 |
| 7 | 566.0 | Miscellaneous Transmission Expenses | 3,411 |
| 8 | 567.0 | Rents | 211 |
| 9 | | Total Operation | 34,888 |
| | | Maintenance | |
| 10 | 568.00 | Supervision and Engineering | 4,645 |
| 11 | 569.00 | Structures | 560 |
| 12 | 570.00 | Station Equipment | 10,607 |
| 13 | 571.62 | Clean Insulators and Bushings | 965 |
| 14 | 571.63 | Replace Line Insulators | 1,246 |
| 15 | 571.64 | Stubbing Poles | 50 |
| 16 | 571.65 | Moving Poles and Guys | 78 |
| 17 | 571.66 | Pole Treating | 41 |
| 18 | 571.67 | Emergency Repairs | 0 |
| 19 | 571.68 | Conductor Reconditioning | 1,376 |
| 20 | 571.69 | Temporary Service Set-Up Work | 167 |
| 21 | 571.70 | Overhaul & Repair Line Equipment | 126 |
| 22 | 571.71 | Paint Poles, Towers & Accessory | 949 |
| 23 | 571.72 | Other Overhead Line Maintenance | 3,985 |
| 24 | 571.73 | Tree Trimming | 2,558 |
| 25 | 571.74 | Vegetation Control | 138 |
| 26 | 571.75 | Right-of-Way Clearing | 740 |
| 27 | 572.00 | Underground Lines | 295 |
| 28 | 573.00 | Miscellaneous Transmission Plant | 49 |
| 29 | | Total Maintenance | 28,575 |
| 30 | | TOTAL TRANSMISSION (1990$) | 63,463 |
| | | Escalation Amounts, 1990 to 1993 | |
| 31 | | Labor | 5,091 |
| 32 | | Non-Labor | 2,805 |
| 33 | | Other | 0 |
| 34 | | Total Escalation | 7,896 |
| 35 | | TOTAL TRANSMISSION (1993$) | 71,359 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

DISTRIBUTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| 1 | | OPERATION | |
| 2 | 580.0 | Supervision and Engineering | $22,961 |
| 3 | 582.0 | Station Expense | 7,931 |
| 3 | 583.2 | Overhead Line Expenses | 12,951 |
| 4 | 583.3 | Removing & Resetting Line Transmission | 5,321 |
| 5 | 584.0 | Underground Line Expenses | 4,766 |
| 6 | 585.0 | Street Lighting & Signal System | 2,179 |
| 7 | 586.0 | Meter Expenses | 24,414 |
| 8 | 587.7 | Invest. & Adj. Service Complaints | 12,688 |
| 9 | 587.8 | Radio & TV Interference Work | 630 |
| 10 | 587.9 | Other Work on Customer Premises | 64 |
| 11 | 588.0 | Miscellaneous Distribution Expenses | 29,187 |
| 12 | 588.6 | Distribution Maps and Records | 6,565 |
| 13 | 589.0 | Rents | 213 |
| 14 | | Total Operation | 129,870 |
| | | MAINTENANCE | |
| 15 | 590.00 | Supervision and Engineering | 13,830 |
| 16 | 591.00 | Structures | 415 |
| 17 | 592.00 | Station Equipment | 7,776 |
| 18 | 593.00 | Overhead Services | 3,172 |
| 19 | 593.62 | Clean Insulators and Bushings | 354 |
| 20 | 593.63 | Replace Line Insulators | 1,810 |
| 21 | 593.64 | Stubbing Poles | 98 |
| 22 | 593.65 | Moving Poles and Guys | 686 |
| 23 | 593.66 | Pole Treating | 348 |
| 24 | 593.67 | Emergency Repairs | 0 |
| 25 | 593.68 | Conductor Reconditioning | 15,193 |
| 26 | 593.69 | Temporary Service Set-Up Work | 520 |
| 27 | 593.70 | Overhaul & Repair Line Equipment | 2,625 |
| 28 | 593.71 | Paint Poles, Towers & Accessory | 36 |
| 29 | 593.72 | Other Overhead Line Maintenance | 7,471 |
| 30 | 593.73 | Tree Trimming | 41,024 |
| 31 | 593.74 | Vegetation Control | 1,178 |
| 32 | 593.75 | Right-Of-Way Clearing | 370 |
| 33 | 594.00 | Underground Lines | 9,464 |
| 34 | 594.00 | Underground Services | 1,025 |
| 35 | 595.00 | Line Transformers | 9,651 |
| 36 | 596.00 | Street Lighting & Signal System | 1,662 |
| 37 | 597.00 | Meters | 902 |
| 38 | 598.00 | Miscellaneous Distribution Plant | 32 |
| 39 | | Total Maintenance | 119,642 |
| 40 | | TOTAL DISTRIBUTION (1990$) | 249,512 |
| | | Escalation Amounts, 1990 to 1993 | |
| 41 | | Labor | 19,510 |
| 42 | | Non-Labor | 11,382 |
| 43 | | Other | 0 |
| 44 | | Total Escalation | 30,892 |
| 45 | | TOTAL DISTRIBUTION (1993$) | 280,404 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

CUSTOMER ACCOUNTS EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| 1 | 901.0 | Supervision | $4,639 |
| 2 | 902.0 | Meter Reading Expenses | 19,919 |
| 3 | 903.0 | Customer Contracts and Orders | 42,157 |
| 4 | 903.0 | Customer Billing & Accounting | 8,745 |
| 5 | 903.0 | Mailing Customer Bills | 9,033 |
| 6 | 903.0 | Collecting Expenses | 18,657 |
| 7 | 904.0 | Uncollectible Accounts | 10,567 |
| 8 | 905.0 | Miscell. Customer Accounts Expense | 8,156 |
| 9 | 905.0 | Rents | 190 |
| 10 | | TOTAL CUSTOMER ACCOUNTS (1990$) | 122,063 |
| 10a | | Steam Department Adjustment | 0 |
| 11 | | Total (Less Uncollectibles) | 111,496 |
| | | Escalation Amounts, 1990 to 1993 | |
| 12 | | Labor | 10,877 |
| 13 | | Non-Labor | 2,686 |
| 14 | | Other | 0 |
| 15 | | Total Escalation | 13,563 |
| 16 | | TOTAL CUSTOMER ACCOUNTS (1993$) | 135,626 |
| 17 | | Total (Less Uncollectibles) | 125,059 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

DEMAND-SIDE MANAGEMENT EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Residential & Non-Residential Conservation, Service Planning, and Load Management Expenses | |
| 1 | 907.0 | Supervision | $3,410 |
| 2 | 908.0 | Customer Assistance Expense | 172,481 |
| 3 | 909.0 | Informational & Instructional Expense | 2,126 |
| 4 | 910.0 | Miscellaneous | 15,285 |
| 5 | | Subtotal | 193,302 |
| | | Load Retention & Load Building Expenses | |
| 6 | 911.0 | Supervision | 133 |
| 7 | 912.0 | Demo/Selling - Load Retention/Building | 1,426 |
| 8 | 912.0 | Demo/Selling - Clean Air Vehicles | 1,800 |
| 9 | 913.0 | Advertising | 0 |
| 10 | 916.0 | Miscellaneous Marketing | 91 |
| 11 | 916.0 | Rents | 0 |
| 12 | | Subtotal | 3,450 |
| 13 | | TOTAL DEMAND-SIDE MANAGEMENT (1990$) | 196,752 |
| | | Escalation Amounts, 1990 to 1993 | |
| 14 | | Labor | 4,597 |
| 15 | | Non-Labor | 16,464 |
| 16 | | Other | 0 |
| 17 | | Total Escalation | 21,061 |
| 18 | | TOTAL DEMAND-SIDE MANAGEMENT (1993$) | 217,813 |

NOTE: Adopted DSM total reflects Joint Recommendation's expense level (see p. B-18) plus Electric Vehicles program and DRA's recommendation on Thermal Storage program. Labor dollars includes PG&E's Performance Incentive Program adjustment.

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

JOINT RECOMMENDATION ON DEMAND-SIDE MANAGEMENT
(Thousands of 1990 Dollars)

| Line No. | Program | Electric -- Joint Recommendation |
|---|---|---|
| | Conservation/Energy Efficiency | |
| | Information | |
| 1 | Residential | $2,843 |
| 2 | Nonresidential | 2,707 |
| | EM Services | |
| 3 | Residential | 7,913 |
| 4 | Nonresidential | 7,225 |
| 5 | Industrial | 1,900 |
| 6 | Agricultural | 2,200 |
| 7 | Direct Assistance | 19,105 |
| | New Contruction | |
| 8 | Residential | 23,878 |
| 9 | Nonresidential | 22,098 |
| | Retrofit Energy Efficiency Incentives | |
| 10 | Residential Weatherization | 1,000 |
| 11 | Residential Appliance Efficiency | 21,670 |
| 12 | Commercial EM Incentives | 22,500 |
| 14 | Industrial EM Incentives | 5,740 |
| 15 | Agricultural EM Incentives | 6,440 |
| 16 | Other DSM (Bidding) | 5,130 |
| | Other | |
| 17 | Residential | 8,991 |
| 18 | Nonresidential | 1,000 |
| | TOTAL CONSERVATION/ENERGY EFFICIENCY | 162,340 |
| | Load Management | |
| 19 | Residential A/C Recycling | 775 |
| 20 | Interruptible/Curtailable | 1,200 |
| 21 | Group Load Curtailment | 438 |
| 22 | TOU (Residential; Nonres.; Mandatory) | 15,618 |
| 23 | Real Time Pricing | 383 |
| 24 | Demand Control Center | 134 |
| 25 | Swimming Pool Pump | 1,502 |
| 26 | TOTAL LOAD MANAGEMENT (Capital dollars) | 20,050 |
| 27 | Fuel Substitution | 1,158 |
| 28 | Load Retention | 1,620 |
| 29 | Load Building | 0 |
| 30 | Measurement & Evaluation | 21,469 |
| 31 | TOTAL: | 206,637 |

NOTE: Above totals do not include Thermal Energy Storage and Electric Vehicles programs. Total DSM expense (i.e., excluding above capital dollars) is reflected on p. B-17.

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

ADMINISTRATIVE AND GENERAL EXPENSES
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 920.0 | Administrative & General Salaries | $106,980 |
| 2 | 921.0 | Office Supplies and Expenses | 68,747 |
| 3 | 922.0 | Admin. & General Transfer Credit | (31,982) |
| 4 | 923.0 | Outside Services Employed | 26,587 |
| 5 | 924.0 | Property Insurance | 13,885 |
| 6 | 925.0 | Injuries and Damages | 49,513 |
| 7 | 926.0 | Employee Pensions and Benefits | 170,452 (a) |
| 8 | 927.0 | Franchise Requirements | 22,582 |
| 9 | 928.0 | Regulatory Commission Expenses | 123 |
| 10 | 930.0 | Research, Development & Demonstration | 27,780 |
| 11 | 930.0 | | 0 |
| 12 | 930.0 | Other Miscellaneous General Expenses | 10,250 |
| 13 | 931.0 | Rents | 15,865 |
| 14 | | Total Operation | 480,781 |
| | | Maintenance | |
| 15 | 935.0 | Maintenance of General Plant | 3,221 |
| 16 | | Total Maintenance | 3,221 |
| 16a | | Steam Dept Adjustment | (508) |
| 17 | | TOTAL ADMINISTRATIVE & GENERAL (1990$) | 483,495 |
| 18 | | Total (Less Franchise Requirements) | 460,913 |
| | | Escalation Amounts, 1990 to 1993 | |
| 19 | | Labor | 13,659 |
| 20 | | Wage Related | 3,600 |
| 21 | | Non-Labor | 12,421 |
| 22 | | Other | 0 |
| 23 | | Medical | 18,191 |
| 24 | | Total Escalation | 47,871 |
| 25 | | TOTAL ADMINISTRATIVE & GENERAL (1993$) | 531,366 |
| 26 | | Total (Less Franchise Requirements) | 508,784 |

(a) Reflects total company Post Retirement Medical expense of $161,898,000 and Group Life expense of $18,749,000, as provided in PG&E's Reply Comments on Proposed Decision in A.91-11-036.

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

TAXES ON OTHER THAN INCOME
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Ad Valorem Taxes | |
| 1 | California | $110,539 |
| 2 | Total Ad Valorem Taxes | 110,539 |
| | Payroll Taxes | |
| 3 | Federal Insurance Contribution Act | 53,451 |
| 4 | Federal Unemployment Insurance | 544 |
| 5 | State Unemployment Insurance | 102 |
| 6 | San Francisco Payroll Tax | 2,019 |
| 7 | Total Payroll Taxes | 56,116 |
| | Other Taxes | |
| 8 | Business Tax | 398 |
| 9 | Hazardous Substance Tax | 1,091 |
| 10 | Total Other Taxes | 1,489 |
| 11 | Super Fund Tax (excluding incremental) | 1,523 |
| 12 | TOTAL TAXES OTHER THAN INCOME | 169,667 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

INCOME TAX ADJUSTMENTS
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | California Income Tax Adjustments | |
| 1 | Fiscal/Calendar Year Adjustment | $572 |
| 2 | Interest Charges | 381,064 |
| 3 | Operating Expense Adjustment | (1,697) |
| 4 | Capitalized Interest Adjustment | (19,010) |
| 5 | Vacation Accrual Reduction | (2,966) |
| 6 | State Tax Depreciation - Dec Balance &) | 573,215 |
| 7 | State Tax Depreciation - Other ) | |
| 8 | Removal Costs | 35,649 |
| 9 | Repair Allowance | 24,710 |
| 10 | Total CCFT Adjustments | $991,537 |
| | Federal Income Tax Adjustments | |
| 11 | Tax Depreciation - SLSR, ) | |
| 12 | " - Dec. Balance, ) | $463,978 |
| 13 | " - ACRS/MARCS & ) | |
| 14 | " - Other ) | |
| 15 | Removal Costs | 26,737 |
| 16 | Repair Allowance | 19,193 |
| 17 | Preferred Dividend Credit | 4,103 |
| 18 | Fiscal/Calendar Year Adjustment | 572 |
| 19 | Interest Charges | 381,064 |
| 20 | Operating Expense Adjustment | (1,697) |
| 21 | Capitalized Interest Adjustment | (19,010) |
| 22 | Vacation Accrual Reduction | (2,966) |
| 23 | Total FIT Adjustments | $871,974 |
| 24 | Federal Tax Depreciation Deferred, ACRS/MACRS | 85,512 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

TAXES ON INCOME
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | **California Corporation Franchise Tax** | |
| 1 | Operating Revenues at Adopted Rates | $3,818,230 |
| 2 | Operating Expenses | 1,529,081 |
| 3 | Nuclear Decommissioning Expense | 54,474 |
| 4 | Taxes Other Than On Income | 169,667 |
| 5 | Income Tax Adjustments | 991,537 |
| 5a | Superfund Tax Increase | 338 |
| 6 | California Taxable Income | 1,073,134 |
| 7 | CCFT Rate | 9.30% |
| 8 | CCFT | 99,801 |
| 9 | State Tax Adjustment | 0 |
| 10 | Subtotal | 99,801 |
| 11 | Defense Facilities Credit | (79) |
| 12 | Deferred Taxes - Interest | (1,768) |
| 13 | Deferred Taxes - Vacation | (276) |
| 14 | TOTAL CALIF. CORPORATE FRANCHISE TAX | 97,678 |
| | **Federal Income Tax** | |
| 15 | Operating Revenues at Adopted Rates | 3,818,230 |
| 16 | Operating Expenses | 1,529,081 |
| 17 | Nuclear Decommissioning Expense | 54,474 |
| 18 | Taxes Other Than On Income | 169,667 |
| 19 | CCFT - Prior Year | 99,510 |
| 20 | Income Tax Adjustments | 871,974 |
| 20a | Superfund Tax Increase | 338 |
| 21 | Federal Taxable Income | 1,093,186 |
| 22 | FIT Rate | 34.00% |
| 23 | Federal Income Tax | 371,683 |
| 24 | Defense Facilities Credit | (689) |
| 25 | Flowback of Excess Deferred Tax | (1,220) |
| 26 | Deferred Tax - ACRS/MACRS | 0 |
| 27 | Deferred Tax - Interest | (5,861) |
| 28 | Deferred Tax - Vacation | (915) |
| 29 | TOTAL FEDERAL INCOME TAX | 362,998 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

AVERAGE LAG IN PAYMENT OF EXPENSES
(Thousands of 1993 dollars)

| Line No. | Description | Expense (A) | Average Lag Days (B) | Product (C=AxB) |
|---|---|---|---|---|
| 1 | Federal Income Tax | 286171 | 121.70 | 34827001 |
| 2 | Nuclear Decommissioning | 54474 | 60.63 | 3302759 |
| 3 | Post-Retirement Medical | 78759 | -16.41 | -1292437 |
| 4 | State Income Tax | 99801 | 83.41 | 8324401 |
| 5 | Uncollectibles | 0 | 0.00 | 0 |
| 6 | Franchise Requirements | 50839 | 257.48 | 13090026 |
| 7 | Fuel Oil | 21363 | 10.27 | 219398 |
| 8 | Geothermal Steam | 92241 | 25.21 | 2325396 |
| 9 | Natural Gas Purchased | 521607 | 41.01 | 21391103 |
| 10 | Nuclear Fuel | 0 | 238.50 | 0 |
| 11 | Purchased Power | 1817021 | 47.39 | 86108625 |
| 12 | Payroll (+ Clearing Account) | 580930 | 13.77 | 7999410 |
| 13 | Property Insurance | 13870 | 5.96 | 82665 |
| 14 | Injuries and Damages | 49459 | 5.96 | 294776 |
| 15 | Pension Expense | 639 | -16.41 | -10492 |
| 16 | Group Life Expense | 10422 | 39.20 | 408539 |
| 17 | Savings Fund Plan | 16771 | 0.00 | 0 |
| 18 | Health, Vision & Dental | 75689 | 9.22 | 697856 |
| 19 | Goods and Services | 473124 | 32.94 | 15584705 |
| 20 | Materials From Storeroom | 184907 | 0.00 | 0 |
| 21 | Depreciation | 660185 | 0.00 | 0 |
| 22 | Ad Valorem Tax - California | 110539 | 44.15 | 4880297 |
| 23 | FICA Tax | 53451 | 3.84 | 205252 |
| 24 | Unemployment Tax - Federal | 544 | 75.33 | 40980 |
| 25 | Unemployment Tax - Calif. | 102 | 75.61 | 7712 |
| 26 | S.F. Payroll & Business Tax | 2417 | 141.18 | 341232 |
| 27 | Abandoned Project Amort. | 7729 | 0.00 | 0 |
| 28 | Deferred Income Taxes | 74704 | 0.00 | 0 |
| 29 | Adjustment to ERTA Tax Basis | 0 | 0.00 | 0 |
| 30 | TOTAL | 5337759 | | 198829202 |
| 31 | Expense Lag Days | 37.25 (Ln.30C / Ln.30A) | | |
| 32 | Revenue Lag Days | 43.21 | | |
| 33 | ADJUSTMENT TO RATE BASE | $87,159 (Ln.32-Ln.31) x Ln.30A / 365 | | |
| 34 | Rate Base | $9,229,817 | | |
| 35 | New Rate Base | $9,316,976 (Ln.33 + Ln.34) | | |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

WORKING CASH CAPITAL SUPPLIED BY INVESTORS
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Operational Cash Requirements | |
| 1 | Required Bank Balances | $43,510 |
| 2 | Special Deposits & Working Funds | 3,478 |
| 3 | Other Receivables | 38,825 |
| 4 | Prepayments | 9,286 |
| 5 | Deferred Debits, Company-Wide | 5,942 |
| 6 | Total | 101,041 |
| | Less: Amounts Not Supplied By Investors | |
| 7 | Accrued Vacation | 130,207 |
| 8 | Working Cash Capital | 11,041 |
| 9 | Total | 141,248 |
| 10 | Subtotal, Total Company | (40,206) |
| 11 | Electric Dept. Allocation Percentage | 67.45% |
| 12 | Electric Department Allocation | (27,119) |
| 13 | Prepayments - Electric Department | 934 |
| 14 | Total Operational Cash Requirement | (26,185) |
| | Plus: Average Amount Required | |
| 15 | Avg Amount Req. as a Result of Paying Expense in Advance of Collecting Rev. | 87,159 |
| 16 | Total | 87,159 |
| 17 | AVERAGE NET AMOUNT OF WORKING CASH CAPITAL SUPPLIED BY INVESTORS | 60,974 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

PLANT-IN-SERVICE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | ELECTRIC PLANT: | |
| 1 | Tangible Plant, BOY 1991 | 12,245,353 |
| 2 | Intangible Plant | 36,352 |
| 3 | Helms | 768,134 |
| 4 | Plant Held For Future Use (PFHU) | 7,129 |
| 5 | BOY 1991 | 13,056,968 |
| 6 | Tan/Intangible Plant Net Additions | 750,593 |
| 7 | Load Management Additions | 12,979 |
| 8 | Hazardous Waste Management Additions | 3,543 |
| 9 | PHFU Additions | (7,129) |
| 10 | BOY 1992 | 13,816,954 |
| 11 | Tan/Intangible Plant Net Additions | 750,015 |
| 12 | Geysers Retirement | (41,911) |
| 13 | Load Management Additions | 9,438 |
| 14 | Hazardous Waste Management Additions | 14,372 |
| 15 | Research, Development & Demonstration | 0 |
| 16 | BOY 1993 | 14,548,868 |
| 17 | Wtd Avg Tan/Intangible Plant Net Add. | 398,780 |
| 18 | Load Management | 5,669 |
| 19 | Hazardous Waste Management | 7,116 |
| 20 | Research, Development and Demonstration | 0 |
| 21 | 1993 Wtd Avg Electric Plant | 14,960,433 |
| | COMMON PLANT - ELECTRIC ALLOCATION: | |
| 22 | Beginning of Year 1991 | 1,190,542 |
| 23 | Helms | 711 |
| 24 | PHFU | 23 |
| 25 | Total BOY 1991 | 1,191,276 |
| 26 | Common Plant Net Additions | 213,131 |
| 27 | Sale of S.F. Steam System | 0 |
| 28 | Hazardous Waste Management | 3,314 |
| 29 | Clean Air Vehicles | 454 |
| 30 | PHFU Additions | (23) |
| 31 | BOY 1992 | 1,408,152 |
| 32 | Common Plant Net Additions | 170,235 |
| 33 | Hazardous Waste Mangement | 763 |
| 34 | Clean Air Vehicles | 613 |
| 35 | PHFU Additions | 0 |
| 36 | BOY 1993 | 1,579,763 |
| 37 | Wtd Avg Common Plant Net Additions | 85,134 |
| 38 | Hazardous Waste Mangement | 344 |
| 39 | Clean Air Vehicles | 0 |
| 40 | PHFU | 0 |
| 41 | 1993 Wtd Avg Common Plant (electric) | 1,665,240 |
| 42 | TOTAL 1993 WTD AVG ELECTRIC PLANT | 16,625,673 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

DEPRECIATION EXPENSE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Depreciation Expense | |
| 1 | Steam Production | $97,359 (a) |
| 2 | Nuclear Production | 0 |
| 3 | Hydraulic Production | 41,192 |
| 4 | Other Production | 3,516 |
| 5 | Transmission | 60,343 |
| 6 | Distribution | 290,224 |
| 7 | General | 7,638 |
| 8 | Subtotal | 500,272 |
| 9 | Fossil Decommissioning | 38,022 |
| 10 | Experimental Plant | 0 |
| 11 | Common Utility Plant Allocation | 121,891 |
| 12 | TOTAL DEPRECIATION EXPENSE | 660,185 |

(a) Reflects 5-year amortization of Geysers Unit 15's undepreciated plant balance ($30.176 million / 5 or $6.035 million).

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

DEPRECIATION RESERVE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED | |
|---|---|---|---|
| | | (B) | |
| | Depreciation Reserve, Beginning of Year | | |
| 1 | Steam Production | $1,278,624 | (a) |
| 2 | Nuclear Production | 0 | |
| 3 | Hydraulic Production | 590,255 | |
| 4 | Other Production | 40,103 | |
| 5 | Transmission | 809,156 | |
| 6 | Distribution | 2,886,554 | |
| 7 | General | 42,135 | |
| 8 | Common Allocation | 605,376 | |
| 9 | Total BOY Depreciation Reserve | 6,252,203 | |
| | Depreciation Reserve, End of Year | | |
| 10 | Steam Production | 1,394,958 | |
| 11 | Nuclear Production | 0 | |
| 12 | Hydraulic Production | 629,458 | |
| 13 | Other Production | 43,230 | |
| 14 | Transmission | 859,585 | |
| 15 | Distribution | 3,111,609 | |
| 16 | General | 49,722 | |
| 17 | Common Allocation | 729,397 | |
| 18 | Total EOY Depreciation Reserve | 6,817,959 | |
| 19 | WEIGHTED AVERAGE DEPRECIATION RESERVE | 6,535,081 | |

(a) Reflects removal of Geysers Unit 15's undepreciated plant balance of $30.176 million from rate base.

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

WEIGHTED AVERAGE DEPRECIATED RATE BASE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Weighted Average Electric Plant | |
| 1 | Electric Plant | $16,625,673 |
| 2 | Adjustments | 0 |
| 3 | Total Weighted Average Plant | 16,625,673 |
| | Working Capital | |
| 4 | Materials and Supplies - Fuel | 0 |
| 5 | Materials and Supplies - Other | 93,429 |
| 6 | Working Cash | 60,974 |
| 7 | Total Working Capital | 154,403 |
| | Tax Reform Act Deferrals | |
| 8 | Deferred Capitalized Interest | 37,565 |
| 9 | Deferred Vacation | 27,622 |
| 10 | Deferred CIAC Tax Effects | 60,351 |
| 11 | Total Adjustments | 125,538 |
| | Less Deductions | |
| 12 | Customer Advances | 114,310 |
| 13 | Accum. Deferred Taxes - Defense | 7,367 |
| 14 | Accum. Deferred Taxes - ACRS | 757,888 |
| 15 | Accum. Deferred Taxes - Other | (14,806) |
| 16 | Deferred ITC | 188,798 |
| 17 | Other | 0 |
| 18 | Total Deductions | 1,053,557 |
| 19 | Depreciation Reserve | 6,535,081 |
| 20 | Adjustments | 0 |
| 21 | TOTAL RATE BASE | 9,316,976 |



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APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Test Year 1993

NET-TO-GROSS MULTIPLIER

| Line No. | Description | (A) | (B) | (C=AxB) |
|---|---|---|---|---|
| 1 | Gross Operating Revenues | | 1.000000 | |
| 2 | Revenues From Customers | | | 0.997900 |
| 3 | Less: Uncollectibles | 0.003000 | 0.997900 | 0.002994 |
| 4 | | | | 0.997006 |
| 5 | Less: Franchise Requirements | 0.006430 | 0.994906 | 0.006397 |
| 6 | | | | 0.990609 |
| 7 | Less: Super Fund Tax | 0.001200 | 0.990609 | 0.001189 |
| 8 | | | | 0.989420 |
| 9 | Less: State Income Tax | 0.093000 | 0.989420 | 0.092016 |
| 10 | | | | 0.898593 |
| 11 | Less: Federal Income Tax | 0.340000 | 0.989420 | 0.336403 |
| 12 | Net Operating Revenues | | | 0.561001 |
| 13 | NET-TO-GROSS MULTIPLIER (Ln.13A / Ln.13B) | 1.000000 | 0.561001 | 1.782527 |

APPENDIX B
PACIFIC GAS AND ELECTRIC COMPANY
Test Year 1993

ESCALATION FACTORS - Total Company
COST OF CAPITAL -- CPUC Jurisdiction

| Line No. | Description | (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|---|---|
| | | | | | Estimated for Attrition Years | |
| | ANNUAL ESCALATION RATES | 1991 | 1992 | 1993 | 1994 | 1995 |
| 1 | Labor | 4.25% | 4.50% | 5.00% | 3.24% | 3.36% |
| 2 | Non-Labor | 3.15% | 2.79% | 3.74% | 3.73% | 3.54% |
| 3 | Other | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 4 | Medical | 12.70% | 13.70% | 10.00% | 3.73% | 3.54% |
| | COMPOSITE ESCALATION FACTORS (1990 dollars to 1993 dollars) | | | | | |
| 5 | Labor | | | 1.1439 | | |
| 6 | Non-Labor | | | 1.0999 | | |
| 7 | Other | | | 1.0000 | | |
| 8 | Medical | | | 1.4095 | | |
| | COST OF CAPITAL (a) | Cost | Capital-ization | Weighted Cost | | |
| 7 | Debt | 8.61% | 47.50% | 4.09% | | |
| 8 | Preferred Stock | 8.35% | 5.75% | 0.48% | | |
| 9 | Common Equity | 11.90% | 46.75% | 5.56% | | |
| 10 | Return on Rate Base (CPUC Jurisdiction) | | | 10.13% | | |

(End of Appendix B)

# APPENDIX C - ELECTRIC DEPARTMENT'S ATTRITION CALCULATION
## PACIFIC GAS AND ELECTRIC COMPANY
## Electric Department, Attrition Years 1994 and 1995

TABLE OF CONTENTS

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

TEST YEAR 1993 -- O&M EXPENSE FOR ATTRITION CALCULATION
(Thousands of Dollars)

| Line No. | Description | TY 1993 | Transfer | Adjusted TY 1993 | CPUC Adjd TY 1993 |
|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) |
| | Production | | | | |
| 1 | Labor | 122,817 | | 122,817 | 122,168 |
| 2 | Non-Labor | 144,654 | | 144,654 | 143,890 |
| 3 | Other | 27,971 | | 27,971 | 27,823 |
| 4 | Total | 295,442 | | 295,442 | 293,882 |
| | Storage | | | | |
| 5 | Labor | 0 | | 0 | 0 |
| 6 | Non-Labor | 0 | | 0 | 0 |
| 7 | Other | 0 | | 0 | 0 |
| 8 | Total | 0 | | 0 | 0 |
| | Transmission | | | | |
| 9 | Labor | 40,471 | | 40,471 | 36,449 |
| 10 | Non-Labor | 30,888 | | 30,888 | 27,819 |
| 11 | Other | 0 | | 0 | 0 |
| 12 | Total | 71,359 | | 71,359 | 64,268 |
| | Distribution | | | | |
| 13 | Labor | 155,089 | | 155,089 | 153,813 |
| 14 | Non-Labor | 125,315 | | 125,315 | 124,284 |
| 15 | Other | 0 | | 0 | 0 |
| 16 | Total | 280,404 | | 280,404 | 278,098 |
| | Customer Accounts | | | | |
| 17 | Labor | 86,462 | | 86,462 | 86,352 |
| 18 | Non-Labor | 29,577 | | 29,577 | 29,539 |
| 19 | Other (excl. Uncollect.) | 9,020 | | 9,020 | 9,009 |
| 20 | Total | 125,059 | | 125,059 | 124,900 |
| | Demand-Side Management | | | | |
| 21 | Labor | 36,546 | | 36,546 | 36,546 |
| 22 | Non-Labor | 181,267 | | 181,267 | 181,267 |
| 23 | Other | 0 | | 0 | 0 |
| 24 | Total | 217,813 | | 217,813 | 217,813 |
| | Administrative & General | | | | |
| 25 | Labor | 108,582 | 0 | 108,582 | 107,091 |
| 26 | Wage Related | 28,617 | 0 | 28,617 | 28,224 |
| 27 | Non-Labor | 136,757 | 0 | 136,757 | 134,879 |
| 28 | Other (excl. Franchise) | 172,213 | 0 | 172,213 | 169,848 |
| 29 | Medical | 62,615 | 0 | 62,615 | 61,755 |
| 30 | Total | 508,784 | 0 | 508,784 | 501,796 |
| | Labor Parity Adjustment | | | | |
| 31 | Labor | (15,385) | | (15,385) | (15,175) |
| 32 | Non-Labor | 0 | | 0 | 0 |
| 33 | Other | 0 | | 0 | 0 |
| 34 | Total | (15,385) | | (15,385) | (15,175) |
| 35 | Labor | 534,582 | 0 | 534,582 | 527,245 |
| 36 | Wage Related | 28,617 | 0 | 28,617 | 28,224 |
| 37 | Non-Labor | 648,458 | 0 | 648,458 | 641,678 |
| 38 | Other | 209,204 | 0 | 209,204 | 206,680 |
| 39 | Medical | 62,615 | 0 | 62,615 | 61,755 |
| 40 | TOTAL O&M EXPENSE | 1,483,476 | 0 | 1,483,476 | 1,465,582 |



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APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

ATTRITION YEARS 1994 & 1995 -- O&M EXPENSE, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | Labor & Wage-Rel. | Non-Labor | Other | Medical | TOTAL |
|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) |
| | Test Year 1993 | | | | | |
| 1 | Base (1993$) | 555,469 | 641,678 | 206,680 | 61,755 | 1,465,582 |
| 2 | 1993 Adopted in GRC | 0.0500 | 0.0374 | 0.0000 | 0.1000 | |
| 3 | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| 4 | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| 5 | Base (1990$) | 485,600 | 583,379 | 206,680 | 43,812 | 1,319,471 |
| | Attrition Year 1994 | | | | | |
| 6 | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| 7 | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| 8 | 1993 (use recorded) | 0.0500 | 0.0374 | 0.0000 | 0.1000 | |
| 9 | 1994 (use updated estimate) | 0.0324 | 0.0373 | 0.0000 | 0.0373 (a) | |
| 10 | Base (1994$) | 573,466 | 665,613 | 206,680 | 64,058 | 1,509,818 |
| 11 | 1994 Escalation | 17,997 | 23,935 | 0 | 2,303 | 44,235 |
| 12 | 1994 Uncollectibles | 54 | 72 | 0 | 7 | 134 |
| 13 | 1994 Franchise Requirement | 116 | 155 | 0 | 15 | 286 |
| 14 | TOTAL 1994 ESCALATION | 18,168 | 24,162 | 0 | 2,325 | 44,655 |
| | Attrition Year 1995 | | | | | |
| 15 | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| 16 | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| 17 | 1993 (use recorded) | 0.0500 | 0.0374 | 0.0000 | 0.1000 | |
| 18 | 1994 (use recorded) | 0.0324 | 0.0373 | 0.0000 | 0.0373 (a) | |
| 19 | 1995 (use updated estimate) | 0.0336 | 0.0354 | 0.0000 | 0.0354 (a) | |
| 20 | Base (1995$) | 592,735 | 689,176 | 206,680 | 66,326 | 1,554,916 |
| 21 | 1995 Escalation | 19,268 | 23,563 | 0 | 2,268 | 45,099 |
| 22 | 1995 Uncollectibles | 58 | 71 | 0 | 7 | 136 |
| 23 | 1995 Franchise Requirement | 124 | 152 | 0 | 15 | 291 |
| 24 | TOTAL 1995 ESCALATION | 19,451 | 23,786 | 0 | 2,289 | 45,526 |

(a) Use non-labor escalation rate for attrition year medical expense.

APPENDIX C

PACIFIC GAS AND ELECTRIC COMPANY

Electric Department, Attrition Years 1994 and 1995

TEST YEAR 1993 -- RATE BASE FOR ATTRITION CALCULATION

(Thousands of Dollars)

| Line No. | Description | Full Year 1993 (A) | Wtd Avg 1993 (B) |
|---|---|---|---|
| 1 | Plant-in-Service: Beginning of Year | 16,128,631 | 16,128,631 |
| 2 | : Additions | 1,092,359 | 497,043 |
| 3 | Total Plant-in-Service, End of Year | 17,220,989 | 16,625,673 |
| 4 | Plant Held For Future Use | 0 | 0 |
| 5 | Total Plant | 17,220,989 | 16,625,673 |
| 6 | Working Capital: Materials & Supplies | 93,429 | 93,429 |
| 7 | : Gas Line Pack | 0 | 0 |
| 8 | : Working Cash | 60,974 | 60,974 |
| 9 | Total Working Capital | 154,403 | 154,403 |
| 10 | TRA Adjustments: Deferred Cap. Interest | 41,042 | 37,565 |
| 11 | : Deferred Vacation Pay | 28,217 | 27,622 |
| 12 | : Deferred CIAC Tax | 64,542 | 60,351 |
| 13 | Total Adjustments | 133,801 | 125,538 |
| 14 | Customer Advances | 114,310 | 114,310 |
| 15 | Accumulated ACRS Deferred Taxes: BOY | 716,008 | 716,008 |
| 16 | : Additions | 81,356 | 41,880 |
| 17 | Total Accumulated ACRS Deferred Taxes | 797,364 | 757,888 |
| 18 | Accumulated Deferred: Investment Tax Credit | 184,912 | 188,798 |
| 19 | : Defense Facilities | 6,983 | 7,367 |
| 20 | : Other | (15,397) | (14,806) |
| 21 | Total Accumulated Deferred | 176,498 | 181,359 |
| 22 | Reserve: Beginning of Year | 6,252,203 | 6,252,203 |
| 23 | : Accrual | 622,163 | 311,082 |
| 24 | : Fossil Decommissioning | 38,022 | 19,011 |
| 25 | : Net Salvage | (94,574) | (47,287) |
| 26 | : Adjustment | 0 | 73 |
| 27 | Total Reserve | 6,817,814 | 6,535,081 |
| 28 | TOTAL RATE BASE | 9,603,207 | 9,316,976 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 -- RATE BASE
(Thousands of Dollars)

| Line No. | Description | Full Year 1994 (A) | Wtd Avg 1994 (B) | Wtd Avg 1994 Increase (C) |
|---|---|---|---|---|
| 1 | Plant-in-Service: BOY | 17,220,989 | 17,220,989 | 595,316 |
| 2 | : Additions | 1,025,239 | 466,502 | 466,502 |
| 3 | Total Plant-in-Service, EOY | 18,246,228 | 17,687,491 | 1,061,818 |
| 4 | Plant Held For Future Use | 0 | 0 | 0 |
| 5 | Total Plant-in-Service | 18,246,228 | 17,687,491 | 1,061,818 |
| 6 | Working Capital: Matls & Supplies | 93,429 | 93,429 | 0 |
| 7 | : Gas Line Pack | 0 | 0 | 0 |
| 8 | : Working Cash | 60,974 | 60,974 | 0 |
| 9 | Total Working Capital | 154,403 | 154,403 | 0 |
| 10 | TRA Adjustments: Def. Cap. Interest | 50,744 | 45,468 | 7,903 |
| 11 | : Def. Vacation Pay | 29,183 | 28,700 | 1,078 |
| 12 | : Def. CIAC Tax | 73,000 | 68,770 | 8,419 |
| 13 | Total Adjustments | 152,927 | 142,938 | 17,400 |
| 14 | Customer Advances | 114,310 | 114,310 | 0 |
| 15 | Accum. ACRS Defer. Taxes: BOY | 797,364 | 797,364 | 81,356 |
| 16 | : Additions | 88,747 | 44,373 | 2,493 |
| 17 | Total Accum. ACRS Deferred Taxes | 886,111 | 841,737 | 83,849 |
| 18 | Accumulated Deferred: Investment Tax | 177,203 | 181,058 | (7,740) |
| 19 | : Defense Facil. | 7,367 | 7,367 | 0 |
| 20 | : Other | (14,806) | (14,806) | 0 |
| 21 | Total Accumulated Deferred | 169,764 | 173,619 | (7,740) |
| 22 | Reserve: BOY | 6,817,814 | 6,817,814 | 282,733 |
| 23 | : Accrual | 661,898 | 330,949 | 299,653 |
| 24 | : Fossil Decommissioning | 38,022 | 19,011 | 0 |
| 25 | : Net Salvage | (100,614) | (50,307) | 0 |
| 26 | : Adjustment | 0 | 0 | 0 |
| 27 | Total Reserve | 7,417,120 | 7,117,467 | 582,386 |
| 28 | TOTAL RATE BASE | 9,966,253 | 9,737,699 | 420,723 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1995 -- RATE BASE
(Thousands of Dollars)

| Line No. | Description | Full Year 1995 (A) | Wtd Avg 1995 (B) | Wtd Avg 1995 Increase (C) |
|---|---|---|---|---|
| 1 | Plant-in-Service: BOY | 18,246,228 | 18,246,228 | 558,737 |
| 2 | : Additions | 1,077,455 | 490,261 | 490,261 |
| 3 | Total Plant, EOY | 19,323,683 | 18,736,489 | 1,048,998 |
| 4 | Plant Held For Future Use | 0 | 0 | 0 |
| 5 | Total Plant-in-Service | 19,323,683 | 18,736,489 | 1,048,998 |
| 6 | Working Capital: Matls & Supplies | 93,429 | 93,429 | 0 |
| 7 | : Gas Line Pack | 0 | 0 | 0 |
| 8 | : Working Cash | 60,974 | 60,974 | 0 |
| 9 | Total Working Capital | 154,403 | 154,403 | 0 |
| 10 | TRA Adjustments: Def. Cap. Interest | 60,242 | 55,456 | 9,988 |
| 11 | : Def. Vacation Pay | 30,134 | 29,658 | 958 |
| 12 | : Def. CIAC Tax | 81,000 | 77,000 | 8,230 |
| 13 | Total Adjustments | 171,376 | 162,114 | 19,176 |
| 14 | Customer Advances | 114,310 | 114,310 | 0 |
| 15 | Accum. ACRS Defer. Taxes: BOY | 886,111 | 886,111 | 88,747 |
| 16 | : Additions | 93,987 | 46,994 | 2,620 |
| 17 | Total Accum. ACRS Deferred Taxes | 980,098 | 933,105 | 91,367 |
| 18 | Accumulated Deferred: Investment Tax | 207,693 | 173,370 | (7,688) |
| 19 | : Defense Facil. | 7,367 | 7,367 | 0 |
| 20 | : Other | (14,806) | (14,806) | 0 |
| 21 | Total Accumulated Deferred | 200,254 | 165,931 | (7,688) |
| 22 | Reserve: BOY | 7,417,120 | 7,417,120 | 299,653 |
| 23 | : Accrual | 701,154 | 350,577 | 316,297 |
| 24 | : Fossil Decommissioning | 38,022 | 19,011 | 0 |
| 25 | : Net Salvage | (106,581) | (53,291) | 0 |
| 26 | : Adjustment | | | |
| 27 | Total Reserve | 8,049,715 | 7,733,418 | 615,950 |
| 28 | TOTAL RATE BASE | 10,305,085 | 10,106,243 | 368,545 |



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APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 1 of 4
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **Depreciation Expense** | | |
| 1 | 1993 Depreciation Expense | 622,163 | |
| 2 | 1993 Wtd Avg Plant-in-Service | 16,625,673 | |
| 3 | = System Average Depreciation Rate | 3.7422% | 3.7422% |
| 4 | x Plant-in-Service Weighted Average Increase | 1,061,818 | 1,048,998 |
| 5 | = Increase in Depreciation Expense | 39,735 | 39,256 |
| 6 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 7 | = Revenue Requirement | 70,829 | 69,974 |
| 8 | x CPUC Allocation Factor | 0.9814821 | 0.9814821 |
| 9 | = CPUC Jurisdiction Revenue Requirement | 69,517 | 68,678 |
| | **Ad Valorem Taxes** | | |
| 10 | 1993 Ad Valorem Taxes | 110,539 | |
| 12 | 1993 Plant-in-Service, BOY | 17,220,989 | |
| 13 | = System Average Ad Valorem Taxes | 0.6419% | 0.6419% |
| 14 | x Current Attrition Year Additions | 1,025,239 | 1,077,455 |
| 15 | = Increase in Ad Valorem Taxes | 6,581 | 6,916 |
| 16 | x Uncoll. & Franchise Net-to-Gross Multiplier | 1.009480 | 1.009480 |
| 17 | = Revenue Requirement | 6,643 | 6,982 |
| 18 | x CPUC Allocation Factor | 0.9794264 | 0.9794264 |
| 19 | = CPUC Jurisdiction Revenue Requirement | 6,506 | 6,838 |
| | **CCFT Depreciation** | | |
| 20 | 1993 CCFT Depreciation | 573,215 | |
| 21 | 1993 Plant-in-Service, BOY | 17,220,989 | |
| 22 | = System Average CCFT Depreciation Rate | 3.3286% | 3.3286% |
| 23 | x Current Attrition Year Additions | 1,025,239 | 1,077,455 |
| 24 | = Increase in CCFT Depreciation Expense | 34,126 | 35,864 |
| 25 | x -CCFT Rate | -9.30% | -9.30% |
| 26 | = California Corporate Franchise Tax | (3,174) | (3,335) |
| 27 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 28 | = Revenue Requirement | (5,657) | (5,945) |
| 29 | California Corporate Franchise Tax | (3,174) | (3,335) |
| 30 | x CPUC Allocation Factor | 0.9823874 | 0.9823874 |
| 31 | = CPUC State Income Taxes | (3,118) | (3,277) |
| 32 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 33 | = CPUC Jurisdiction Revenue Requirement | (5,558) | (5,841) |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 2 of 4
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **FIT Depreciation** | | |
| 1 | 1993 FIT Depreciation | 463,978 | |
| 2 | 1993 Plant-in-Service, BOY | 17,220,989 | |
| 3 | = System Average FIT Depreciation Rate | 2.6943% | 2.6943% |
| 4 | x Current Attrition Year Additions | 1,025,239 | 1,077,455 |
| 5 | = Increase in FIT Depreciation Expense | 27,623 | 29,030 |
| 6 | x -FIT Rate | -34.00% | -34.00% |
| 7 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 8 | = Revenue Requirement | (16,741) | (17,594) |
| 9 | x CPUC Allocation Factor | 0.9819270 | 0.9819270 |
| 10 | = CPUC Jurisdiction Revenue Requirement | (16,438) | (17,276) |
| 11 | Net Increase in FIT Depreciation Expense | 27,623 | 29,030 |
| 12 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 13 | x Super Fund Tax Net-to-Gross Multiplier | 1.010693 | 1.010693 |
| 14 | = Super Fund Tax Effect on Fed. Tax Dep. Incr | (34) | (35) |
| 15 | Total Revenue Requirement | (16,775) | (17,629) |
| 16 | x CPUC Allocation Factor | 0.9819270 | 0.9819270 |
| 17 | = Total CPUC Jurisdiction Revenue Requirement | (16,472) | (17,310) |
| | **Prior Year's CCFT Deductible for FIT** | | |
| 18 | Prior Year's Revenue Requirement (Excl. Super Fund Tax Effect) | | 70,829 |
| 19 | + Depreciation | | (4,662) |
| 20 | + CCFT Depreciation | | (13,105) |
| 21 | + FIT Depreciation | | 3,600 |
| 22 | + Rate Base: Preferred Stock | | 41,697 |
| 23 | + : Common Stock Equity | | (176) |
| 24 | + CCFT | | 98,183 |
| 25 | = Prior Year's Revenue Requirement | | 0.092016 |
| 26 | x CCFT Cumulative Component | | 9,034 |
| 27 | = CCFT Increase | | (2,616) |
| 28 | + Prior Year's CCFT for CCFT Depreciation Expense | | 6,419 |
| 29 | = Total CCFT Increase | | |
| 30 | Prior Year's CCFT Subtotal | 99,801 | 106,220 |
| 31 | - Prior Year's CCFT Deductible for FIT | 99,510 | 99,801 |
| 32 | = Increase in CCFT Deduction for FIT | 291 | 6,419 |
| 33 | x -FIT Rate | -34.00% | -34.00% |
| 34 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 35 | = Revenue Requirement (FIT) | (176) | (3,890) |
| 36 | Net Increase in CCFT Deductible for FIT | 291 | 6,419 |
| 37 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 38 | x Super Fund Tax Net-to-Gross Multiplier | 1.010693 | 1.010693 |
| 39 | = Super Fund Tax Effect on Incr. in Deduction | 0 | (8) |
| 40 | Total Revenue Requirement (FIT and Super Fund Tax) | (176) | (3,898) |



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APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 3 of 4
(Thousands of Dollars)

| Line No. | Description | 1994 | 1995 |
|---|---|---|---|
| | **CPUC Jurisdiction California Corporation Franchise Tax** | | |
| | Prior Year's Revenue Requirement (Excl. Super Fund Tax Effect) | | 69,517 |
| 1 | + Depreciation | | (4,581) |
| 2 | + CCFT Depreciation | | (12,868) |
| 3 | + FIT Depreciation | | 3,524 |
| 4 | + Rate Base: Preferred Stock | | 40,818 |
| 5 | + : Common Stock Equity | | (479) |
| 6 | + CCFT | | 95,931 |
| 7 | = Prior Year's Revenue Requirement | | 0.092016 |
| 8 | x CCFT Cumulative Component | | 8,827 |
| 9 | = CCFT Increase | | (2,570) |
| 10 | + Prior Year's CCFT for CCFT Depreciation Expense | | 6,258 |
| 11 | = Total CCFT Increase (CPUC Jurisdiction) | | |
| 12 | Prior Year's CCFT Subtotal | 97,757 | 104,014 |
| 13 | - Prior Year's CCFT Deduction for FIT | 96,967 | 97,757 |
| 14 | = Increase in CCFT Deduction for FIT | 790 | 6,258 |
| 15 | x -FIT Rate | -34.00% | -34.00% |
| 16 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 17 | = CPUC Jurisdiction Revenue Requirement (FIT) | (479) | (3,792) |
| 18 | Net Increase in CCFT Deduction on FIT | 790 | 6,258 |
| 19 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 20 | x Super Fund Tax Net-to-Gross Multiplier | 1.010693 | 1.010693 |
| 21 | = Super Fund Tax Effect on Incr. in Deduction | (1) | (8) |
| 22 | Total CPUC Jurisdiction Revenue Requirement (FIT and Super Fund Tax) | (480) | (3,800) |



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# APPENDIX C
## PACIFIC GAS AND ELECTRIC COMPANY
### Electric Department, Attrition Years 1994 and 1995

### AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 4 of 4
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | RATE BASE | | |
| 1 | Prior Year's Weighted Average Rate Base | 9,316,976 | 9,737,699 |
| 2 | Current Attrition Year's Wtd Avg Rate Base | 9,737,699 | 10,106,243 |
| | LONG-TERM DEBT | | |
| 3 | Prior Year's Return on Debt | 8.61% | 8.61% |
| 4 | x Prior Year's Debt Capitalization | 47.50% | 47.50% |
| 5 | = Prior Year's Weighted Cost of Debt | 4.09% | 4.09% |
| 6 | Change in Weighted Average Rate Base | 420,723 | 368,545 |
| 7 | x Prior Year's Weighted Average Cost of Debt | 4.09% | 4.09% |
| 8 | = Change in Weighted Cost of Debt | 17,208 | 15,073 |
| 9 | x Uncoll. & Franchise Net-to-Gross Multiplier | 1.009480 | 1.009480 |
| 10 | = Revenue Requirement | 17,371 | 15,216 |
| 11 | x CPUC Allocation Factor | 0.9789131 | 0.9789131 |
| 12 | = CPUC Jurisdiction Revenue Requirement | 17,005 | 14,895 |
| | PREFERRED STOCK | | |
| 13 | Prior Year's Return on Preferred Stock | 8.35% | 8.35% |
| 14 | x Prior Year's Preferred Stock Capitalization | 5.75% | 5.75% |
| 15 | = Prior Year's Wtd Cost of Preferred Stock | 0.48% | 0.48% |
| 16 | Change in Weighted Average Rate Base | 420,723 | 368,545 |
| 17 | x Prior Year's Wtd Cost of Preferred Stock | 0.48% | 0.48% |
| 18 | = Change in Weighted Cost of Preferred Stock | 2,019 | 1,769 |
| 19 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 20 | = Increase in Revenue Requirement | 3,600 | 3,153 |
| 21 | x CPUC Allocation Factor | 0.9789131 | 0.9789131 |
| 22 | = CPUC Jurisdiction Revenue Requirement | 3,524 | 3,087 |
| | COMMON EQUITY | | |
| 23 | Prior Year's Return on Common Equity | 11.90% | 11.90% |
| 24 | x Prior Year's Common Equity Capitalization | 46.75% | 46.75% |
| 25 | = Prior Year's Weighted Cost of Common Equity | 5.56% | 5.56% |
| 26 | Change in Weighted Average Rate Base | 420,723 | 368,545 |
| 27 | x Prior Year's Weighted Cost of Common Equity | 5.56% | 5.56% |
| 28 | = Change in Weighted Cost of Common Equity | 23,392 | 20,491 |
| 29 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 30 | = Increase in Revenue Requirement | 41,697 | 36,526 |
| 31 | x CPUC Allocation Factor | 0.9789131 | 0.9789131 |
| 32 | = CPUC Jurisdiction Revenue Requirement | 40,818 | 35,756 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- FINANCIAL COMPONENTS
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **RATE BASE** | | |
| 1 | Weighted Average Rate Base | 9,737,699 | 10,106,243 |
| | **LONG-TERM DEBT** | | |
| 2 | Prior Year's Return on Debt | 8.61% | |
| 3 | x Prior Year's Debt Capitalization | 47.50% | |
| 4 | x Uncoll.& Franchise Net-to-Gross Multiplier | 1.009480 | |
| 5 | = Prior Year's Gross Weighted Cost of Debt | 0.041288 | |
| 6 | Current Attrition Year's Return on Debt | 8.61% | 8.61% |
| 7 | x Current AY's Debt Capitalization | 47.50% | 47.50% |
| 8 | x Uncoll.& Franchise Net-to-Gross Multiplier | 1.009480 | 1.009480 |
| 9 | = AY Gross Weighted Cost of Debt | 0.041288 | 0.041288 |
| 10 | Change in Gross Weighted Cost of Debt | 0.000000 | 0.000000 |
| 11 | x Weighted Average Rate Base | 9,737,699 | 10,106,243 |
| 12 | = Change in Revenue Requirement | 0 | 0 |
| 13 | x CPUC Allocation Factor | 0.0000000 | 0.0000000 |
| 14 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |
| | **PREFERRED STOCK** | | |
| 15 | Prior Year's Return on Preferred Stock | 8.35% | |
| 16 | x Prior Year's Pref. Stock Capitalization | 5.75% | |
| 17 | x Net-to-Gross Mulitiplier | 1.782527 | |
| 18 | = Prior Year's Gross Wtd Cost of Pref. Stock | 0.008556 | |
| 19 | Current Attrition Year's Return on Pref. Stock | 8.35% | 8.35% |
| 20 | x Current AY's Pref. Stock Capitalization | 5.75% | 5.75% |
| 21 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 22 | = AY Gross Weighted Cost of Preferred Stock | 0.008556 | 0.008556 |
| 23 | Change in Gross Wtd Cost of Preferred Stock | 0.000000 | 0.000000 |
| 24 | x Weighted Average Rate Base | 9,737,699 | 10,106,243 |
| 25 | = Change in Revenue Requirement | 0 | 0 |
| 26 | x CPUC Allocation Factor | 0.0000000 | 0.0000000 |
| 27 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |
| | **COMMON EQUITY** | | |
| 28 | Prior Year's Return on Common Equity | 11.90% | |
| 29 | x Prior Year's Common Equity Capitalization | 46.75% | |
| 30 | x Net-to-Gross Mulitiplier | 1.782527 | |
| 31 | = Prior Yr's Gross Wtd Cost of Common Equity | 0.099109 | |
| 32 | Current Attrition Year's Return on Common Equit | 11.90% | 11.90% |
| 33 | x Current AY's Common Equity Capitalization | 46.75% | 46.75% |
| 34 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 35 | = AY Gross Weighted Cost of Common Equity | 0.099109 | 0.099109 |
| 36 | Change in Gross Wtd Cost of Common Equity | 0.000000 | 0.000000 |
| 37 | x Weighted Average Rate Base | 9,737,699 | 10,106,243 |
| 38 | = Change in Revenue Requirement | 0 | 0 |
| 39 | x CPUC Allocation Factor | 0.0000000 | 0.0000000 |
| 40 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- OTHER ITEMS & ADJUSTMENTS
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | State ADR Tax Depreciation Adjustment | | |
| 1 | State ADR Tax Depreciation Adjustment | (6,000) | (6,000) |
| 2 | x -CCFT Rate | -9.30% | -9.30% |
| 3 | = CCFT | 558 | 558 |
| 4 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 5 | = Revenue Requirement | 995 | 995 |
| 6 | California Corporate Franchise Tax | 558 | 558 |
| 7 | x CPUC Allocation Factor | 0.9823874 | 0.9823874 |
| 8 | = CPUC Jurisdiction CCFT | 548 | 548 |
| 9 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 10 | = CPUC Jurisdiction Revenue Requirement | 977 | 977 |
| | Federal ADR Tax Depreciation Adjustment | | |
| 11 | Federal ADR Tax Depreciation Adjustment | (6,000) | (6,000) |
| 12 | x -FIT Rate | -34.00% | -34.00% |
| 13 | x Net-to-Gross Mulitiplier | 1.782527 | 1.782527 |
| 14 | = Revenue Requirement | 3,636 | 3,636 |
| 15 | x CPUC Allocation Factor | 0.9819270 | 0.9819270 |
| 16 | = CPUC Jurisdiction Revenue Requirement | 3,570 | 3,570 |
| 17 | Federal ADR Tax Depreciation Adjustment | (6,000) | (6,000) |
| 18 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 19 | x Super Fund Tax Net-to-Gross Multiplier | 1.010693 | 1.010693 |
| 20 | = Super Fund Tax Effect on Change in FIT Dep. | 7 | 7 |
| 21 | Total Revenue Requirement | 3,643 | 3,643 |
| 22 | x CPUC Allocation Factor | 0.9819270 | 0.9819270 |
| 23 | = Total CPUC Jurisdiction Revenue Requirement | 3,577 | 3,577 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CHANGE IN REVENUE REQUIREMENT, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | Atttrition Year 1994 | Atttrition Year 1995 |
|---|---|---|---|
| | | (A) | (B) |
| | Operating & Maintenance Expense | | |
| 1 | Labor Escalation | $18,168 | $19,451 |
| 2 | Non-Labor Escalation | 24,162 | 23,786 |
| 3 | Medical Escalation | 2,325 | 2,289 |
| 4 | Total Operation & Maintenance Expense | 44,655 | 45,526 |
| | Capital-Related Items | | |
| 5 | Book Depreciation Expense | 69,517 | 68,678 |
| 6 | Ad Valorem Taxes | 6,506 | 6,838 |
| 7 | Prior Year's CCFT | (480) | (3,800) |
| 8 | State Tax Depreciation | (4,581) | (4,864) |
| 9 | Federal Tax Depreciation | (12,895) | (13,733) |
| 10 | Rate Base: Debt Cost | 17,005 | 14,895 |
| 11 | : Preferred Stock Cost | 3,524 | 3,087 |
| 12 | : Common Equity Cost | 40,818 | 35,756 |
| 13 | Total Capital-Related Items | 119,414 | 106,857 |
| | Financial Component | | |
| 14 | Debt Cost | 0 | 0 |
| 15 | Preferred Stock Cost | 0 | 0 |
| 16 | Common Equity Cost | 0 | 0 |
| 17 | Total Financial Component | 0 | 0 |
| | Other Items | | |
| 18 | Other | 0 | 0 |
| 19 | Total Other Items | 0 | 0 |
| 20 | SUBTOTAL | 164,069 | 152,383 |
| | Special Projects | | |
| 21 | NOx Reduction | 0 | 0 |
| 22 | TOTAL CHANGE IN REVENUE REQUIREMENT | $164,069 | $152,383 |



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APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 -- RESULTS OF OPERATIONS, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | TY 1993 Adopted | 1994 Increase | Attrition Year 1994 |
|---|---|---|---|---|
| | | (A) | (B) | (C=A+B) |
| | Operating Revenues | | | |
| 1 | Revenues | $3,753,557 | $164,072 | $3,917,630 |
| 2 | Total Operating Revenues | 3,753,557 | 164,072 | 3,917,630 |
| | Operating Expenses | | | |
| 3 | Energy Cost | 85 | 0 | 85 |
| 4 | Production | 265,444 | 0 | 265,444 |
| 5 | Transmission | 57,157 | 0 | 57,157 |
| 6 | Distribution | 247,460 | 0 | 247,460 |
| 7 | Customer Accounts | 111,354 | 0 | 111,354 |
| 8 | Uncollectibles | 11,430 | 491 | 11,921 |
| 9 | Demand-Side Management | 196,752 | 0 | 196,752 |
| 10 | Administrative & General | 454,583 | 0 | 454,583 |
| 11 | Franchise Requirements | 24,008 | 1,050 | 25,058 |
| 12 | Project Amortization | 7,465 | 0 | 7,465 |
| 13 | Adjustments | 0 | 0 | 0 |
| 14 | Subtotal (1990 Dollars) | 1,375,738 | 1,541 | 1,377,278 |
| 15 | Labor Adjustment To Parity | (15,175) | 0 | (15,175) |
| 16 | Labor Escalation Amount | 71,785 | 17,997 | 89,782 |
| 17 | Non-Labor Escalation Amount | 76,223 | 26,238 | 102,461 |
| 18 | Subtotal (1993 Dollars) | 1,508,571 | 45,776 | 1,554,347 |
| 19 | Super Fund Tax Increase | 343 | 88 | 430 |
| 20 | Depreciation | 648,416 | 39,000 | 687,416 |
| 21 | Nuclear Decommissioning Expense | 54,119 | 0 | 54,119 |
| 22 | Taxes Other Than On Income | 166,582 | 6,446 | 173,027 |
| 23 | Calif. Corporation Franchise Tax | 95,679 | 6,258 | 101,937 |
| 24 | Federal Income Tax | 355,941 | 24,785 | 380,726 |
| 25 | Total Operating Expenses | 2,829,650 | 122,352 | 2,952,001 |
| 26 | Net Operating Revenues | $923,908 | $41,720 | $965,628 |
| 27 | Net Return on Rate Base | 923,908 | 41,720 | 965,628 |
| 28 | Adjusted Rate Base | 9,120,510 | 411,851 | 9,532,361 |
| 29 | Rate of Return | 10.13% | 10.13% | 10.13% |

| | |
|---|---|
| Currently Adopted ROR | 10.13% |
| Net-to-Gross | 1.78253 |
| Additional Revenues | (0) |
| Revenues | 3,917,630 |
| New Revenue Estimate | 3,917,630 |



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APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1994 -- TAXES ON INCOME, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | TY 1993 Adopted (A) | 1994 Increase (B) | Attrition Year 1994 (C=A+B) |
|---|---|---|---|---|
| | California Corporation Franchise Tax | | | |
| 1 | Operating Revenues | $3,753,557 | $164,072 | $3,917,630 |
| 2 | Operating Expenses | 1,508,571 | 45,776 | 1,554,347 |
| 3 | Nuclear Decommissioning Expense | 54,119 | 0 | 54,119 |
| 4 | Taxes Other Than On Income | 166,582 | 6,446 | 173,027 |
| 5 | Income Tax Adjustments | 972,795 | 44,475 | 1,017,270 |
| 6 | Super Fund Tax Increase | 343 | 88 | 430 |
| 7 | California Taxable Income | 1,051,148 | 67,288 | 1,118,436 |
| 8 | CCFT Rate | 9.30% | 9.30% | 9.30% |
| 9 | CCFT | 97,757 | 6,258 | 104,015 |
| 10 | CCFT Adjustment | 0 | 0 | 0 |
| 11 | Subtotal | 97,757 | 6,258 | 104,015 |
| 12 | Defense Facilities Credit | (77) | 0 | (77) |
| 13 | Deferred Taxes - Interest | (1,731) | 0 | (1,731) |
| 14 | Deferred Taxes - Vacation | (270) | 0 | (270) |
| 15 | Total CCFT | $95,679 | $6,258 | $101,937 |
| | Federal Income Tax | | | |
| 16 | Operating Revenues | $3,753,557 | $164,072 | $3,917,630 |
| 17 | Operating Expenses | 1,508,571 | 45,776 | 1,554,347 |
| 18 | Nuclear Decommissioning Expens | 54,119 | 0 | 54,119 |
| 19 | Taxes Other Than On Income | 166,582 | 6,446 | 173,027 |
| 20 | Prior Year's CCFT | 96,967 | 790 | 97,757 |
| 21 | Income Tax Adjustments | 855,089 | 38,077 | 893,165 |
| 22 | Super Fund Tax Increase | 343 | 88 | 430 |
| 23 | Federal Taxable Income | 1,071,888 | 72,896 | 1,144,784 |
| 24 | FIT Rate | 34.00% | 34.00% | 34.00% |
| 25 | Federal Income Tax | 364,442 | 24,785 | 389,227 |
| 26 | Defense Facilities Credit | (674) | 0 | (674) |
| 27 | Flowback of Excess Deferred Tax | (1,194) | 0 | (1,194) |
| 28 | Deferred Tax - ACRS/MACRS | 0 | 0 | 0 |
| 29 | Deferred Tax - Interest | (5,737) | 0 | (5,737) |
| 30 | Deferred Tax - Vacation | (896) | 0 | (896) |
| 31 | Total FIT | $355,941 | $24,785 | $380,726 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1995 -- RESULTS OF OPERATIONS, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | Attrition Year 1994 | 1995 Increase | Attrition Year 1995 |
|---|---|---|---|---|
| | | (A) | (B) | (C=A+B) |
| | Operating Revenues | | | |
| 1 | Revenues | $3,917,630 | $152,385 | $4,070,015 |
| 2 | Total Operating Revenues | 3,917,630 | 152,385 | 4,070,015 |
| | Operating Expenses | | | |
| 3 | Energy Cost | 85 | 0 | 85 |
| 4 | Production | 265,444 | 0 | 265,444 |
| 5 | Transmission | 57,157 | 0 | 57,157 |
| 6 | Distribution | 247,460 | 0 | 247,460 |
| 7 | Customer Accounts | 111,354 | 0 | 111,354 |
| 8 | Uncollectibles | 11,921 | 456 | 12,377 |
| 9 | Demand-Side Management | 196,752 | 0 | 196,752 |
| 10 | Administrative & General | 454,583 | 0 | 454,583 |
| 11 | Franchise Requirements | 25,058 | 975 | 26,033 |
| 12 | Project Amortization | 7,465 | 0 | 7,465 |
| 13 | Adjustments | 0 | 0 | 0 |
| 14 | Subtotal (1990 Dollars) | 1,377,278 | 1,431 | 1,378,709 |
| 15 | Labor Adjustment To Parity | (15,175) | 0 | (15,175) |
| 16 | Labor Escalation Amount | 89,782 | 19,268 | 109,051 |
| 17 | Non-Labor Escalation Amount | 102,461 | 25,830 | 128,292 |
| 18 | Subtotal (1993 Dollars) | 1,554,347 | 46,530 | 1,600,877 |
| 19 | Super Fund Tax Increase | 430 | 67 | 497 |
| 20 | Depreciation | 687,416 | 38,529 | 725,944 |
| 21 | Nuclear Decommissioning Expense | 54,119 | 0 | 54,119 |
| 22 | Taxes Other Than On Income | 173,027 | 6,774 | 179,801 |
| 23 | Calif. Corporation Franchise Tax | 101,937 | 5,108 | 107,045 |
| 24 | Federal Income Tax | 380,726 | 18,832 | 399,558 |
| 25 | Total Operating Expenses | 2,952,001 | 115,839 | 3,067,840 |
| 26 | Net Operating Revenues | 965,628 | 36,546 | 1,002,174 |
| 27 | Net Return on Rate Base | 965,628 | 36,546 | 1,002,174 |
| 28 | Adjusted Rate Base | 9,532,361 | 360,773 | 9,893,134 |
| 29 | Rate of Return | 10.13% | 10.13% | 10.13% |

| | |
|---|---|
| Currently Adopted ROR | 10.13% |
| Net-to-Gross | 1.78253 |
| Additional Revenues | (0) |
| Revenues | 4,070,015 |
| New Revenue Estimate | $4,070,015 |

APPENDIX C
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department, Attrition Years 1994 and 1995

AY 1995 -- TAXES ON INCOME, CPUC Jurisdiction
(Thousands of Dollars)

| Line No. | Description | Attrition Year 1994 (A) | 1995 Increase (B) | Attrition Year 1995 (C=A+B) |
|---|---|---|---|---|
| | California Corporation Franchise Tax | | | |
| 1 | Operating Revenues | $3,917,630 | $152,385 | $4,070,015 |
| 2 | Operating Expenses | 1,554,347 | 46,530 | 1,600,877 |
| 3 | Nuclear Decommissioning Expense | 54,119 | 0 | 54,119 |
| 4 | Taxes Other Than On Income | 173,027 | 6,774 | 179,801 |
| 5 | Income Tax Adjustments | 1,017,270 | 44,094 | 1,061,364 |
| 6 | Super Fund Tax Increase | 430 | 67 | 497 |
| 7 | California Taxable Income | 1,118,436 | 54,921 | 1,173,357 |
| 8 | CCFT Rate | 9.30% | 9.30% | 9.30% |
| 9 | CCFT | 104,015 | 5,108 | 109,123 |
| 10 | CCFT Adjustment | 0 | 0 | 0 |
| 11 | Subtotal | 104,015 | 5,108 | 109,123 |
| 12 | Defense Facilities Credit | (77) | 0 | (77) |
| 13 | Deferred Taxes - Interest | (1,731) | 0 | (1,731) |
| 14 | Deferred Taxes - Vacation | (270) | 0 | (270) |
| 15 | Total CCFT | $101,937 | $5,108 | $107,045 |
| | Federal Income Tax | | | |
| 16 | Operating Revenues | $3,917,630 | $152,385 | $4,070,015 |
| 17 | Operating Expenses | 1,554,347 | 46,530 | 1,600,877 |
| 18 | Nuclear Decommissioning Expens | 54,119 | 0 | 54,119 |
| 19 | Taxes Other Than On Income | 173,027 | 6,774 | 179,801 |
| 20 | Prior Year's CCFT | 97,757 | 6,258 | 104,014 |
| 21 | Income Tax Adjustments | 893,165 | 37,369 | 930,535 |
| 22 | Super Fund Tax Increase | 430 | 67 | 497 |
| 23 | Federal Taxable Income | 1,144,784 | 55,388 | 1,200,172 |
| 24 | FIT Rate | 34.00% | 34.00% | 34.00% |
| 25 | Federal Income Tax | 389,227 | 18,832 | 408,059 |
| 26 | Defense Facilities Credit | (674) | 0 | (674) |
| 27 | Flowback of Excess Defer'd Tax | (1,194) | 0 | (1,194) |
| 28 | Deferred Tax - ACRS/MACRS | 0 | 0 | 0 |
| 29 | Deferred Tax - Interest | (5,737) | 0 | (5,737) |
| 30 | Deferred Tax - Vacation | (896) | 0 | (896) |
| 31 | Total FIT | $380,726 | $18,832 | $399,558 |

(End of Appendix C)

APPENDIX D - GAS DEPARTMENT'S RESULTS OF OPERATIONS
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

TABLE OF CONTENTS

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department

JANUARY 1, 1993 CONSOLIDATED REVENUE CHANGES
($000)

| LINE NO. | DESCRIPTION | PRESENT RATE REVENUE (c) | REVENUE CHANGE | ADOPTED REVENUE REQUIREMENT | |
|---|---|---|---|---|---|
| | | (A) | (B) | (C) | |
| 1 | Procurement | $850,153 | | $850,153 | |
| 2 | Firm Surcharge Credit | (5,830) | | (5,830) | |
| 3 | CPUC Fee | 4,388 | | 4,388 | |
| 4 | CFA | 4,874 | | 4,874 | |
| 5 | GEDA | 16,932 | | 16,932 | |
| 6 | ASS Interutility Account | 0 | | 0 | |
| 7 | LIRA | 8,928 | | 8,928 | |
| 8 | Transporation Cost & TOP True-Up | (7,443) | | (7,443) | |
| 9 | EOR | 716 | | 716 | |
| 10 | Non Base Gas Fixed Cost | 317,029 | | 317,029 | |
| 11 | GCEE Incentive Recovery | 901 | 3,414 | 4,315 | (b) |
| 12 | | ----------- | | ----------- | |
| 13 | Total Before Base | 1,190,648 | 3,414 | 1,194,062 | |
| 14 | | | | | |
| 15 | GENERAL RATE CASE REVENUES | | | 1,287,311 | (a) |
| 16 | OTHER OPERATING REVENUES | | | (7,105) | (a) |
| 17 | TEFRA RECOVERY (1st of 6 yrs) | | | 368 | (a) |
| 18 | | | | | |
| 19 | Preliminary Statement Adjustments | | | | |
| 20 | Long-Term Contract Revenue | 0 | | 0 | |
| 21 | EOR Forecasted from EOR Payments | (10,399) | | (10,399) | |
| 22 | Third-Party Interutility | 0 | | 0 | |
| 23 | Brokerage Fee | (6,637) | | (6,637) | |
| 24 | G-10 Allocated Employees Discount | 660 | | 660 | |
| 25 | | ----------- | | ----------- | |
| 26 | TOTAL GAS FIXED COST ACCOUNT - BASE | 1,199,325 | 64,873 | 1,264,198 | |
| 27 | | | | | |
| 28 | TOTAL REVENUES | 2,389,973 | 68,287 | 2,458,260 | |
| 29 | | | | | |
| 30 | Percent Increase Over Revenues at Present Rates | | 2.86% | | |

NOTES:
(a) Adopted in this decision.
(b) Adopted in PG&E's ECAC D.92-11-046.
(c) Reflects one-year average of the two-year BCAP revenues adopted in D.92-10-051.



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# APPENDIX D
## PACIFIC GAS AND ELECTRIC COMPANY
## Gas Department, Test Year 1993

### SUMMARY OF EARNINGS, COMPARISON
### (Thousands of Dollars)

| Line No. | Description | PG&E (A) | DRA (B) | ADOPTED (C) |
|---|---|---|---|---|
| | **Operating Revenues** | | | |
| 1 | GRC Revenues at Present Rates | $1,215,701 | $1,215,701 | $1,215,701 |
| 2 | GRC Change in Revenue | 113,396 | 2,470 | 71,610 |
| 3 | Total GRC Revenues | 1,329,097 | 1,218,171 | 1,287,311 |
| | **Operating Expenses** | | | |
| 4 | Natural Gas Used by Gas Dept | 0 | 0 | 0 |
| 5 | Underground and Local Storage | 10,145 | 7,645 | 7,645 |
| 6 | Production | 3,590 | 3,543 | 3,590 |
| 7 | Transmission | 40,604 | 40,443 | 40,604 |
| 8 | Distribution | 121,555 | 116,709 | 119,932 |
| 9 | Customer Accounts | 87,950 | 85,822 | 82,566 |
| 10 | Uncollectibles | 3,332 | 3,121 | 3,227 |
| 11 | Demand-Side Management | 62,973 | 57,797 | 56,149 |
| 12 | Administrative & General | 199,205 | 177,853 | 187,999 |
| 13 | Franchise Requirements | 9,712 | 9,095 | 9,407 |
| 14 | Project Amortization | 351 | 351 | 351 |
| 15 | Adjustments | 0 | 0 | 0 |
| 16 | Subtotal, 1990 Dollars | 539,417<br>0 | 502,379 | 511,470 |
| 17 | Labor Adjustment For Parity | 0 | (16,703) | (6,728) |
| 18 | Labor Escalation Amount | 33,573 | 0 | 31,844 |
| 19 | Non-Labor Escalation Amount | 28,738 | 18,223 | 27,269 |
| 20 | Subtotal, 1993 Dollars | 601,728 | 503,899 | 563,855 |
| 21 | Depreciation | 246,983 | 245,439 | 246,632 |
| 22 | Super Fund Tax Increase | 135 | (74) | 85 |
| 23 | Taxes Other Than On Income | 57,445 | 51,632 | 54,803 |
| 24 | California Corporation Franchise Tax | 31,096 | 30,789 | 31,058 |
| 25 | Federal Income Tax | 112,676 | 111,429 | 112,500 |
| 26 | Total Operating Expenses | 1,050,063 | 943,114 | 1,008,933 |
| 27 | Net Operating Revenues | 279,034 | 275,057 | 278,378 |
| 28 | Return on Rate Base | 279,034 | 275,057 | 278,378 |
| 29 | Rate Base | 2,753,720 | 2,715,270 | 2,748,051 |
| 30 | Rate of Return | 10.13% | 10.13% | 10.13% |

NOTE: For comparison purposes, columns A and B have been recalculated by CACD staff to reflect adopted 1993 cost of capital.

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

FRANCHISE FEES & UNCOLLECTIBLES
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | AT ADOPTED RATES | |
| 1 | General Rate Case Revenues | $1,287,311 |
| 2 | Percentage of Revenues From Customers | 83.57% |
| 3 | GRC Revenues From Customers | 1,075,806 |
| 1 | Uncollectible Factor | 0.3000% |
| 2 | Uncollectibles | 3,227 |
| 6 | Revenues From Customers | 1,075,806 |
| 7 | Uncollectibles | (3,227) |
| 8 | Net Revenues From Customers | 1,072,579 |
| 9 | Franchise Requirement Factor | 0.8770% |
| 10 | Franchise Requirements | 9,407 |
| 11 | Franchise Amortization | 0 |
| 12 | Total Franchise Requirements | 9,407 |



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# APPENDIX D
## PACIFIC GAS AND ELECTRIC COMPANY
## Gas Department, Test Year 1993

### EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | **TOTAL NON-ESCALATED** | |
| 1 | Production | $3,590 |
| 2 | Underground Storage | 7,212 |
| 3 | Local Storage | 433 |
| 4 | Other | 0 |
| 5 | Total Production and Storage | 11,235 |
| 6 | Transmission | 40,604 |
| 7 | Distribution | 119,932 |
| 8 | Customer Accounts | 85,614 |
| 9 | Demand-Side Management | 56,149 |
| 10 | Administrative and General | 196,882 |
| 11 | Total Non-Escalated (1990$) | 510,416 |
| 12 | Adjustments: | 3.20% |
| 13 | | 0.00% |
| | **TOTAL ESCALATED** | |
| 14 | Production | 4,050 |
| 15 | Underground Storage | 7,953 |
| 16 | Local Storage | 484 |
| 17 | Other | 0 |
| 18 | Total Production and Storage | 12,487 |
| 19 | Transmission | 45,616 |
| 20 | Distribution | 135,293 |
| 21 | Customer Accounts | 95,516 |
| 22 | Demand-Side Management | 62,162 |
| 23 | Administrative and General | 218,455 |
| 24 | Total Escalated (1993$) | 569,529 |
| | **TOTAL ESCALATION (1990$ to 1993$)** | |
| 25 | Production | 460 |
| 26 | Underground Storage | 741 |
| 27 | Local Storage | 51 |
| 28 | Other | 0 |
| 29 | Total Production and Storage | 1,252 |
| 30 | Transmission | 5,012 |
| 31 | Distribution | 15,361 |
| 32 | Customer Accounts | 9,902 |
| 33 | Demand-Side Management | 6,013 |
| 34 | Administrative and General | 21,573 |
| 35 | Total Escalation | 59,113 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

LABOR EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | LABOR NON-ESCALATED (1990$) | |
| 1 | Production | $2,283 |
| 2 | Underground Storage | 912 |
| 3 | Local Storage | 189 |
| 4 | Other | 0 |
| 5 | Total Production and Storage | 3,384 |
| 6 | Transmission | 21,709 |
| 7 | Distribution | 76,824 |
| 8 | Customer Accounts | 54,330 |
| 9 | Demand-Side Management | 9,171 |
| 10 | Administrative and General | 44,823 |
| 11 | Adjustments | 0 |
| 12 | Total Non-Escalated Labor | 210,241 |
| 13 | Non-Escalated Wage-Related A&G | 11,048 |
| 14 | Total | 221,289 |
| 14a | Parity Adjustment | (6,728) |
| 15 | Labor Escalation Factor | 1.1439 |
| | LABOR ESCALATED (1993$) | |
| 16 | Production | 2,612 |
| 17 | Underground Storage | 1,043 |
| 18 | Local Storage | 216 |
| 19 | Other | 0 |
| 20 | Total Production and Storage | 3,871 |
| 21 | Transmission | 24,833 |
| 22 | Distribution | 87,879 |
| 23 | Customer Accounts | 62,148 |
| 24 | Demand-Side Management | 10,491 |
| 25 | Administrative and General | 51,273 |
| 26 | Adjustments | 0 |
| 27 | Total Escalated Labor | 240,495 |
| 28 | Escalated Wage-Related A&G | 12,638 |
| 29 | Total Escalated Labor & Wage-Related | 253,133 |
| | LABOR ESCALATION (1990$ to 1993$) | |
| 30 | Production | 329 |
| 31 | Underground Storage | 131 |
| 32 | Local Storage | 27 |
| 33 | Other | 0 |
| 34 | Total Production and Storage | 487 |
| 35 | Transmission | 3,124 |
| 36 | Distribution | 11,055 |
| 37 | Customer Accounts | 7,818 |
| 38 | Demand-Side Management | 1,320 |
| 39 | Administrative and General | 6,450 |
| 40 | Adjustments | 0 |
| 41 | Total Labor Escalation | 30,254 |
| 42 | Wage-Related A&G Escalation | 1,590 |
| 43 | Total Labor & Wage-Related Escalation | 31,844 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

NON-LABOR EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | NON-LABOR NON-ESCALATED (1990$) | |
| 1 | Production | $1,307 |
| 2 | Underground Storage | 6,102 |
| 3 | Local Storage | 244 |
| 4 | Other | 0 |
| 5 | Total Production and Storage | 7,653 |
| 6 | Transmission | 18,895 |
| 7 | Distribution | 43,108 |
| 8 | Customer Accounts | 20,856 |
| 9 | Demand-Side Management | 46,978 |
| 10 | Administrative and General | 55,039 |
| 11 | Total Non-Escalated Non-Labor | 192,529 |
| 12 | Non-Labor Escalation Factor | 1.0999 |
| | NON-LABOR ESCALATED (1993$) | |
| 13 | Production | 1,438 |
| 14 | Underground Storage | 6,712 |
| 15 | Local Storage | 268 |
| 16 | Other | 0 |
| 17 | Total Production and Storage | 8,418 |
| 18 | Transmission | 20,783 |
| 19 | Distribution | 47,414 |
| 20 | Customer Accounts | 22,940 |
| 21 | Demand-Side Management | 51,671 |
| 22 | Administrative and General | 60,538 |
| 23 | Total Escalated Non-Labor | 211,764 |
| | NON-LABOR ESCALATION (1990$ to 1993$) | |
| 24 | Production | 131 |
| 25 | Underground Storage | 610 |
| 26 | Local Storage | 24 |
| 27 | Other | 0 |
| 28 | Total Production and Storage | 765 |
| 29 | Transmission | 1,888 |
| 30 | Distribution | 4,306 |
| 31 | Customer Accounts | 2,084 |
| 32 | Demand-Side Management | 4,693 |
| 33 | Administrative and General | 5,499 |
| 34 | Adjustments | 0 |
| 35 | Total Non-Labor Escalation | 19,235 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

OTHER EXPENSE SUMMARY
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Description | ADOPTED |
|---|---|---|
| | OTHER NON-ESCALATED (1990$) | |
| 1 | Production | $0 |
| 2 | Underground Storage | 198 |
| 3 | Local Storage | 0 |
| 4 | Other | 0 |
| 5 | Total Production and Storage | 198 |
| 6 | Transmission | 0 |
| 7 | Distribution | 0 |
| 8 | Customer Accounts | 10,428 |
| 9 | Demand-Side Management | 0 |
| 10 | A&G - Other & Medical | 85,972 |
| 11 | Total Non-Escalated Other | 96,598 |
| 12 | Medical Escalation Factor | 1.4095 |
| 13 | Other Escalation Factor | 1.0000 |
| | OTHER ESCALATED (1993$) | |
| 14 | Production | 0 |
| 15 | Underground Storage | 198 |
| 16 | Local Storage | 0 |
| 17 | Other | 0 |
| 18 | Total Production and Storage | 198 |
| 19 | Transmission | 0 |
| 20 | Distribution | 0 |
| 21 | Customer Accounts | 10,428 |
| 22 | Demand-Side Management | 0 |
| 23 | A&G - Other & Medical | 94,006 |
| 24 | Total Escalated Other | 104,632 |
| | OTHER (and Medical) ESCALATION | |
| 25 | Production | 0 |
| 26 | Underground Storage | 0 |
| 27 | Local Storage | 0 |
| 28 | Other | 0 |
| 29 | Total Production and Storage | 0 |
| 30 | Transmission | 0 |
| 31 | Distribution | 0 |
| 32 | Customer Accounts | 0 |
| 33 | Demand-Side Management | 0 |
| 34 | A&G - Other & Medical | 8,034 |
| 35 | Total Other (and Medical) Escalation | 8,034 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

PRODUCTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 710.0 | Supervision and Engineering | $4 |
| 2 | 717.0 | Liquifed Petroleum Gas | 0 |
| 3 | 733.0 | Gas Mixing | 3 |
| 4 | 735.0 | Miscellaneous Production | 6 |
| 5 | 798.0 | Gas Exploration & Development | 0 |
| 6 | 807.2 | Purchased Gas Meas. Stations | 582 |
| 7 | 807.4 | Purchased Gas Calculations | 1,580 |
| 8 | 807.5 | Other Purchased Gas Supply | 604 |
| 9 | 813.0 | Other Gas Supply | 313 |
| 10 | | Total Operation | 3,092 |
| | | Maintenance | |
| 11 | 740.0 | Supervision and Engineering | 45 |
| 12 | 741.0 | Structures and Inprovements | 3 |
| 13 | 742.0 | Production Equipment | 450 |
| 14 | | Total Maintenance | 498 |
| 15 | | TOTAL PRODUCTION (1990$) | 3,590 |
| | | Escalation Amounts, 1990 to 1993 | |
| 16 | | Labor | 329 |
| 17 | | Non-Labor | 131 |
| 18 | | Other | 0 |
| 19 | | Total Escalation | 460 |
| 20 | | TOTAL PRODUCTION (1993$) | 4,050 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

UNDERGROUND STORAGE EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 814.0 | Supervision and Engineering | $79 |
| 2 | 815.0 | Maps and Records | 0 |
| 3 | 816.0 | Wells | 112 |
| 4 | 817.0 | Lines | 0 |
| 5 | 818.0 | Compressor Station | 586 |
| 6 | 819.0 | Compressor Sta Fuel & Power | 3,486 |
| 7 | 820.0 | Measuring & Regulating Station | 322 |
| 8 | 821.0 | Purification | 0 |
| 9 | 824.0 | Other | 24 |
| 10 | 825.0 | Storage Well Royalties | 198 |
| 11 | | Total Operation | 4,807 |
| | | Maintenance | |
| 12 | 830.0 | Supervision and Engineering | 38 |
| 13 | 831.0 | Structures and Improvements | 1,730 |
| 14 | 832.0 | Reservoirs and Wells | 139 |
| 15 | 833.0 | Lines | 44 |
| 16 | 834.0 | Compressor Station Equipment | 13 |
| 17 | 835.0 | Measuring & Reg Station Equip. | 17 |
| 18 | 836.0 | Purification Equipment | 13 |
| 19 | 837.0 | Other Equipment | 411 |
| 20 | | Total Maintenance | 2,405 |
| 21 | | TOTAL UNDERGROUND STORAGE (1990$) | 7,212 |
| | | Escalation Amounts, 1990 to 1993 | |
| 22 | | Labor | 131 |
| 23 | | Non-Labor | 610 |
| 24 | | Other | 0 |
| 25 | | Total Escalation | 741 |
| 26 | | TOTAL UNDERGROUND STORAGE (1993$) | 7,953 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

LOCAL STORAGE EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 840.0 | Supervision and Engineering | $10 |
| 2 | 841.0 | Operation Labor and Expenses | 51 |
| 3 | 842.1 | Fuel | 0 |
| 4 | 842.2 | Power | 28 |
| 5 | | Total Operation | 89 |
| | | Maintenance | |
| 6 | 843.1 | Supervision and Engineering | 31 |
| 7 | 843.2 | Structures and Improvements | 0 |
| 8 | 843.3 | Gas Holders | 60 |
| 9 | 843.7 | Compressor Equipment | 253 |
| 10 | 843.9 | Other Equipment | 0 |
| 11 | | Total Maintenance | 344 |
| | | TOTAL LOCAL STORAGE (1990$) | 433 |
| | | Escalation Amounts, 1990 to 1993 | |
| 12 | | Labor | 27 |
| 13 | | Non-Labor | 24 |
| 14 | | Other | 0 |
| 15 | | Total Escalation | 51 |
| 16 | | TOTAL LOCAL STORAGE (1993$) | 484 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

TRANSMISSION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 850.0 | Supervision and Engineering | $4,034 |
| 2 | 851.0 | System Control & Load Dispatching | 6,312 |
| 3 | 853.0 | Compressor Station | 4,381 |
| 4 | 854.0 | Compressor Station Fuel | 0 |
| 5 | 855.0 | Other Fuel & Power for Com. Stations | 410 |
| 6 | 856.0 | Mains Expense | 2,129 |
| 7 | 856.0 | Revoval of Condensate | 312 |
| 8 | 857.0 | Measuring & Regulating Station Expense | 2,063 |
| 9 | 858.0 | Transmission & Comp. of Gas by Others | 0 |
| 10 | 859.0 | Transmission Maps & Records | 205 |
| 11 | 859.0 | Other Expenses | 3,471 |
| 12 | 859.0 | Joint Expenses | 1,271 |
| 13 | 860.0 | Rents | 78 |
| 14 | | Total Operation | 24,666 |
| | | Maintenance | |
| 15 | 861.0 | Supervision and Engineering | 1,446 |
| 16 | 862.0 | Structures and Improvements | 278 |
| 17 | 863.0 | Mains | 5,586 |
| 18 | 864.0 | Compressor Station Equipment | 7,216 |
| 18 | 865.0 | Measuring & Reg Station Equipment | 1,237 |
| 20 | 867.0 | Other Equipment | 175 |
| 21 | | Total Maintenance | 15,938 |
| 22 | | TOTAL TRANSMISSION (1990$) | 40,604 |
| | | Escalation Amounts, 1990 to 1993 | |
| 23 | | Labor | 3,124 |
| 24 | | Non-Labor | 1,888 |
| 25 | | Other | 0 |
| 26 | | Total Escalation | 5,012 |
| 27 | | TOTAL TRANSMISSION (1993$) | 45,616 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

DISTRIBUTION EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | OPERATION | |
| 1 | 870.0 | Supervision and Engineering | $10,240 |
| 2 | 871.0 | Load Dispatching | 754 |
| 3 | 874.0 | Mains and Services | 3,259 |
| 4 | 875.0 | Meas. & Reg. Stations - General | 618 |
| 5 | 876.0 | Meas. & Reg. Stations - Industrial | 764 |
| 6 | 877.0 | Rem & Reset Regulators | 19,272 |
| 7 | 878.0 | Rem & Reset Regs & Meters | 598 |
| 8 | 879.0 | Miscellaneous Meter Expenses | 0 |
| 9 | 879.0 | Customer Instal. Expense - General | 23,405 |
| 10 | 880.0 | Maps and Records | 3,882 |
| 11 | 880.0 | Other Expenses | 22,498 |
| 12 | 881.0 | Rents | 34 |
| | | Total Operation | 85,324 |
| | | MAINTENANCE | |
| 13 | 885.0 | Supervision and Engineering | 4,669 |
| 14 | 886.0 | Structures and Improvements | 1 |
| 15 | 887.0 | Mains - Leak Clamps | 1,606 |
| 16 | 887.0 | Mains - Other | 11,701 |
| 17 | 888.0 | Compressor Station Equipment | 0 |
| 18 | 889.0 | Meas. & Reg. Station - General | 2,018 |
| 19 | 890.0 | Meas. & Reg. Station - Industrial | 828 |
| 20 | 892.0 | Services | 9,244 |
| 21 | 893.0 | Meters | 3,208 |
| 22 | 893.0 | House Regulators | 909 |
| 23 | 894.0 | Other Equipment | 424 |
| 24 | | Total Maintenance | 34,608 |
| 25 | | TOTAL DISTRIBUTION (1990$) | 119,932 |
| | | Escalation Amounts, 1990 to 1993 | |
| 26 | | Labor | 11,055 |
| 27 | | Non-Labor | 4,306 |
| 28 | | Other | 0 |
| 29 | | Total Escalation | 15,361 |
| 30 | | TOTAL DISTRIBUTION (1993$) | 135,293 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

CUSTOMER ACCOUNTS EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| 1 | 901.0 | Supervision | $3,779 |
| 2 | 902.0 | Meter Reading Expenses | 16,027 |
| 3 | 903.0 | Customer Contracts and Orders | 25,552 |
| 4 | 903.0 | Customer Billing & Accounting | 7,490 |
| 5 | 903.0 | Mailing Customer Bills | 7,412 |
| 6 | 903.0 | Collecting Expenses | 14,664 |
| 7 | 904.0 | Uncollectible Accounts | 3,048 |
| 8 | 905.0 | Misc. Customer Accounts Expenses | 7,515 |
| 9 | 905.0 | Rents | 127 |
| 10 | | TOTAL CUSTOMER ACCOUNTS (1990$) | 85,614 |
| 11 | | Total (Less Uncollectibles) | 82,566 |
| | | Escalation Amounts, 1990 to 1993 | |
| 11 | | Labor | 7,818 |
| 12 | | Non-Labor | 2,084 |
| 13 | | Other | 0 |
| 14 | | Total Escalation | 9,902 |
| 15 | | TOTAL CUSTOMER ACCOUNTS (1993$) | 95,516 |
| 16 | | Total (Less Uncollectibles) | 92,468 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

DEMAND-SIDE MANAGEMENT EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Residential & Non-Residential Conservation, Measurement Evaluation and Other Program Expenses | |
| 1 | 907.0 | Supervision | $976 |
| 2 | 908.0 | Customer Assistance Expense | 47,669 |
| 3 | 909.0 | Informational & Instruct. Expense | 1,001 |
| 4 | 910.0 | Miscellaneous | 5,609 |
| 5 | | Subtotal | 55,255 |
| | | Load Retention & Load Building Expense | |
| 6 | 911.0 | Supervision | 73 |
| 7 | 912.0 | Demo/Selling - Load Retetion/Building | 776 |
| 8 | 912.0 | Demo/Selling - Clean Air Vehicle | 0 |
| 9 | 913.0 | Advertising | 0 |
| 10 | 916.0 | Miscellaneous | 45 |
| 11 | 916.0 | Rents | 0 |
| 12 | | Subtotal | 894 |
| 13 | | TOTAL DEMAND-SIDE MANAGEMENT (1990$) | 56,149 |
| | | Escalation Amounts, 1990 to 1993 | |
| 14 | | Labor | 1,320 |
| 15 | | Non-Labor | 4,693 |
| 16 | | Other | 0 |
| 17 | | Total Escalation | 6,013 |
| 18 | | TOTAL DEMAND-SIDE MANAGEMENT (1993$) | 62,162 |

NOTE: Adopted DSM total reflects Joint Recommendation's expense level (see p. D-15). Labor dollars include PG&E's Performance Incentive Program adjustment.

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

JOINT RECOMMENDATION ON DEMAND-SIDE MANAGEMENT
(Thousands of 1990 Dollars)

| Line No. | Program | Gas -- Joint Recommendation |
|---|---|---|
| | Conservation/Energy Efficiency | |
| | Information | |
| 1 | Residential | $751 |
| 2 | Nonresidential | 250 |
| | EM Services | |
| 3 | Residential | 9,051 |
| 4 | Nonresidential | 1,400 |
| 5 | Industrial | 800 |
| 6 | Agricultural | 600 |
| 7 | Direct Assistance | 16,488 |
| | New Contruction | |
| 8 | Residential | 10,332 |
| 9 | Nonresidential | 1,002 |
| | Retrofit Energy Efficiency Incentives | |
| 10 | Residential Weatherization | 4,000 |
| 11 | Residential Appliance Efficiency | 330 |
| 12 | Commercial EM Incentives | 2,500 |
| 13 | Industrial EM Incentives | 1,260 |
| 14 | Agricultural EM Incentives | 560 |
| 15 | Other DSM (Bidding) | 570 |
| | Other | |
| 16 | Residential | 602 |
| 17 | Nonresidential | 0 |
| 18 | TOTAL CONSERVATION/ENERGY EFFICIENCY | 50,496 |
| | Load Management | |
| 19 | Residential A/C Recycling | N/A |
| 20 | Interruptible/Curtailable | N/A |
| 21 | Group Load Curtailment | N/A |
| 22 | TOU (Res.; Nonres; Mandatory) | N/A |
| 23 | Real Time Pricing | N/A |
| 24 | Demand Control Center | N/A |
| 25 | Swimming Pool Pump | N/A |
| 26 | TOTAL LOAD MANAGEMENT (Capital dollars) | 0 |
| 27 | Fuel Substitution | 0 |
| 28 | Load Retention | 880 |
| 29 | Load Building | 0 |
| 30 | Measurement & Evaluation | 6,047 |
| 31 | TOTAL: | 57,423 |

NOTE: Total DSM excluding capital dollars is reflected on p. D-14.

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

ADMINISTRATIVE AND GENERAL EXPENSE
(Thousands of 1990 dollars unless otherwise indicated)

| Line No. | Account No. | Description | ADOPTED |
|---|---|---|---|
| | | Operation | |
| 1 | 920.0 | Administrative & General Salaries | $49,127 |
| 2 | 921.0 | Office Supplies and Expenses | 32,095 |
| 3 | 922.0 | Admin. & General Transfer Credit | (14,782) |
| 4 | 923.0 | Outside Services Employed | 11,772 |
| 5 | 924.0 | Property Insurance | 1,362 |
| 6 | 925.0 | Injuries and Damages | 11,043 |
| 7 | 926.0 | Employee Pensions and Benefits | 75,191 (a) |
| 8 | 927.0 | Franchise Requirements | 8,883 |
| 9 | 928.0 | Regulatory Commission Expenses | 59 |
| 10 | 930.0 | Research, Development, & Demonstration | 7,930 |
| 11 | 930.0 | | 0 |
| 12 | 930.2 | Other Miscellaneous General Expenses | 5,024 |
| 13 | 931.0 | Rents | 7,629 |
| 14 | | Total Operation | 195,333 |
| | | Maintenance | |
| 15 | 935.0 | Maintenance of General Plant | 1,549 |
| 16 | | Total Maintenance | 1,549 |
| 17 | | TOTAL ADMINISTRATIVE & GENERAL (1990$) | 196,882 |
| 18 | | Total (Less Franchise Requirements) | 187,999 |
| | | Escalation Amounts 1990 to 1993 | |
| 19 | | Labor | 6,450 |
| 20 | | Non-Labor | 5,498 |
| 21 | | Other | 0 |
| | | Medical | 8,034 |
| 22 | | Total Escalation | 11,948 |
| 23 | | TOTAL ADMINISTRATIVE & GENERAL (1993$) | 208,830 |
| 24 | | Total (Less Franchise Requirements) | 199,947 |

(a) Reflects total company Post Retirement Medical expense of $161,898,000 and Group Life expense of $18,749,000, as provided in PG&E's Reply Comments on Proposed Decision in A.91-11-036.



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

TAX OTHER THAN ON INCOME
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Ad Valorem Taxes | |
| 1 | California | $29,837 |
| 2 | Total Ad Valorem Taxes | 29,837 |
| | Payroll Taxes | |
| 3 | Federal Insurance Contribution Act | 22,401 |
| 4 | Federal Unemployment Insurance | 242 |
| 5 | State Unemployment Insurance | 61 |
| 6 | San Francisco Payroll Tax | 841 |
| 7 | Total Payroll Taxes | 23,545 |
| | Other Taxes | |
| 8 | Business Tax | 175 |
| 9 | Hazardous Substance Tax | 593 |
| 10 | Total Other Taxes | 768 |
| 11 | Super Fund Tax (excluding incremental) | 653 |
| 12 | TOTAL TAXES OTHER THAN ON INCOME | 54,803 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

INCOME TAX ADJUSTMENTS
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | California Income Tax Adjustments | |
| 1 | State Tax Depreciation-Dec. Bal.& Other | $212,622 |
| 2 | Fiscal/Calendar Year Adjustment | 593 |
| 3 | Interest Charges | 112,395 |
| 4 | Operating Expense Adjustment | (727) |
| 5 | Capitalized Interest Adjustment | (10,454) |
| 6 | Capitalized Inventory Adjustments | (1,343) |
| 7 | Vacation Accrual Reduction | (1,271) |
| 8 | Capitalized Use Taxes | 0 |
| 9 | Capitalized Ad Valorem Taxes | 0 |
| 10 | Capitalized Pension & Benefits | 0 |
| 11 | Removal Costs | 6,927 |
| 12 | Repair Allowance | 4,148 |
| 13 | Total CCFT Adjustments | 322,890 |
| | Federal Income Tax Adjustments | |
| 14 | Fiscal/Calendar Year Adjustment | $593 |
| 15 | Interest Charges | 112,395 |
| 16 | Operating Expense Adjustment | (727) |
| 17 | Capitalized Interest Adjustment | (10,454) |
| 18 | Capitalized Inventory Adjustments | (1,343) |
| 19 | Vacation Accrual Reduction | (1,271) |
| 20 | Capitalized Use Taxes | 0 |
| 21 | Capitalized Ad Valorem Taxes | 0 |
| 22 | Capitalized Pension & Benefits | 0 |
| 23 | Federal Operating Expense Adjustment | 0 |
| 24 | Federal Tax Depreciation-SLRL, ) | |
| 25 | Federal Tax Depreciation-Dec. Bal., ) | 180,705 |
| 26 | Federal Tax Depreciation-ACRS/MACRS& ) | |
| 27 | Federal Tax Depreciation-Other ) | |
| 28 | Removal Costs | 5,195 |
| 29 | Repair Allowance | 3,817 |
| 30 | Preferred Divident Credit | 697 |
| 31 | Total FIT Adjustments | 289,607 |
| 32 | Federal Tax Depreciation Deferred, ACRS/MACRS | 26,532 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

TAXES ON INCOME
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | California Corporation Franchise Tax | |
| 1 | Operating Revenues At Adopted Rates | $1,287,311 |
| 2 | Operating Expenses | 563,855 |
| 2a | Super Fund Tax Increase | 85 |
| 3 | Taxes Other Than On Income | 54,803 |
| 4 | Income Tax Adjustments | 322,890 |
| 5 | California Taxable Income | 345,678 |
| 6 | CCFT Rate | 9.30% |
| 7 | CCFT | 32,148 |
| 8 | Defense Facilities Credit | 0 |
| 9 | Deferred Taxes - Other | 0 |
| 10 | Deferred Taxes - Interest | (972) |
| 11 | Deferred Taxes - Vacation | (118) |
| 12 | TOTAL CALIF. CORPORATE FRANCHISE TAX | 31,058 |
| | Federal Income Tax | |
| 13 | Operating Revenues at Adopted Rates | 1,287,311 |
| 14 | Operating Expenses | 563,855 |
| 14a | Super Fund Tax Increase | 85 |
| 15 | Taxes Other Than On Income | 54,803 |
| 16 | Prior Year's CCFT | 35,796 |
| 17 | Income Tax Adjustments | 289,607 |
| 18 | Federal Taxable Income | 343,165 |
| 19 | FIT Rate | 34.00% |
| 21 | Federal Income Tax | 116,676 |
| 22 | Flowback of Excess Deferred Tax | (560) |
| 23 | Defense Facilities Credit | 0 |
| 24 | Deferred Tax - ACRS/MACRS | 0 |
| 25 | Deferred Tax - Interest & Vacation | (3,616) |
| 26 | Amortization of ITC | 0 |
| 27 | TOTAL FEDERAL INCOME TAX | 112,500 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

AVERAGE LAG IN PAYMENT OF EXPENSE
(Thousands of 1993 dollars)

| Line No. | Description | Expense | Average Lag Days | Product |
|---|---|---|---|---|
| | | (A) | (B) | (C=AxB) |
| 1 | Natural Gas Purchased | 526,186 | 41.01 | 21578888 |
| 2 | Federal Income Tax | 90,144 | 121.70 | 10970525 |
| 3 | State Income Tax | 32,148 | 83.41 | 2681465 |
| 4 | Franchise Requirements | 17,988 | 257.48 | 4631550 |
| 5 | Payroll (+ Clearing Account) | 254,035 | 13.77 | 3498061 |
| 6 | Property Insurance | 1,362 | 5.96 | 8118 |
| 7 | Injuries and Damages | 11,043 | 5.96 | 65816 |
| 8 | Pension Expense | 282 | -16.41 | -4628 |
| 9 | Group Life Expense | 4,602 | 39.20 | 180417 |
| 10 | Savings Fund Plan | 7,406 | 0.00 | 0 |
| 11 | Health, Vision & Dental | 33,448 | 9.22 | 308392 |
| 12 | Goods and Services | 147,092 | 32.94 | 4845210 |
| 13 | Materials From Storeroom | 57,487 | 0.00 | 0 |
| 14 | Depreciation | 246,632 | 0.00 | 0 |
| 15 | Ad Valorem Tax - California | 29,837 | 44.15 | 1317304 |
| 16 | FICA Tax | 22,401 | 3.84 | 86020 |
| 17 | Unemployment Tax - Federal | 242 | 75.33 | 18230 |
| 18 | Unemployment Tax - Calif. | 61 | 75.61 | 4612 |
| 19 | S.F. Payroll Tax | 1,016 | 141.18 | 143439 |
| 20 | Post Retirement Medical | 34,743 | -16.41 | -570133 |
| 21 | Deferred Income Taxes | 21,266 | 0.00 | 0 |
| 22 | Abandoned Project Amort. | 351 | 0.00 | 0 |
| 23 | TOTAL | 1,539,773 | | 49763286 |
| 24 | Expense Lag Days = (C)/(A) = | 32.32 (Ln.23C / Ln.23A) | | |
| 25 | Revenue Lag Days | 43.21 | | |
| 26 | ADJUSTMENT TO RATE BASE | $45,940 (Ln.25-Ln.24) x Ln.23A / 365 | | |
| 27 | Rate Base | $2,702,111 | | |
| 28 | New Rate Base | $2,748,051 (Ln.26 + Ln.27) | | |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

WOXRING CASH CAPITAL SUPPLIED BY INVESTORS
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Operational Cash Requirements | |
| 1 | Required Bank Balances | $43,510 |
| 2 | Special Deposits & Working Funds | 3,478 |
| 3 | Other Receivables | 38,825 |
| 4 | Prepayments | 9,286 |
| 5 | Deferred Debits, Company-Wide | 5,942 |
| 6 | Total | 101,041 |
| | Less: Amounts Not Supplied By Investors | |
| 7 | Accrued Vacation | 130,207 |
| 8 | Working Cash Capital | 11,041 |
| 9 | Total | 141,248 |
| 10 | Subtotal, Total Company | (40,206) |
| 11 | Gas Dept. Allocation Percentage | 32.44% |
| 12 | Gas Department Allocation | (13,043) |
| 13 | Miscell. Deferred Credits - Gas Dept. | 3 |
| 14 | Total Operational Cash Requirement | ($13,040) |
| | Plus: Average Amount Required | |
| 16 | Avg. Amount Req. as a Result of Paying Expense in Advance of Collecting Rev. | 45,940 |
| 17 | Total | 45,940 |
| 18 | AVERAGE NET AMOUNT OF WORKING CASH CAPITAL SUPPLIED BY INVESTORS | $32,900 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

PLANT-IN-SERVICE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | GAS PLANT: | |
| 1 | Tan/Intangible Plant, BOY 1991 | $3,640,569 |
| 2 | StanPac (6/7 Interest) | 20,212 |
| 3 | Plant Held For Future Use | 0 |
| 4 | BOY 1991 | 3,660,781 |
| 5 | Net Plant Additions | 330,680 |
| 6 | Hazardous Waste Management | (1,347) |
| 7 | CNG Vehicles | 316 |
| 8 | StanPac (6/7 Int) Net Additions | 4,315 |
| 9 | BOY 1992 | 3,994,745 |
| 10 | Net Plant Additions | 292,697 |
| 11 | Hazardous Waste Management | 6,427 |
| 12 | CNG Vehicles | 7,239 |
| 13 | StanPac (6/7 Int) Net Additions | 1,033 |
| 14 | BOY 1993 | 4,302,141 |
| 15 | Wtd Avg Net Plt Additions | 162,769 |
| 16 | Hazardous Waste Management | 2,208 |
| 17 | CNG Vehicles | (11) |
| 18 | StanPac (6/7) Wtd Avg Net Additions | 153 |
| 19 | Wtd Avg Gas Plant, 1993 | 4,467,260 |
| | COMMON PLANT - GAS ALLOCATION: | |
| 20 | Beginning of Year 1991 | 572,590 |
| 21 | Helms | 342 |
| 22 | Plant Held For Future Use | 11 |
| 23 | Total BOY 1991 | 572,943 |
| 24 | Common Plant Net Additions | 102,506 |
| 25 | Sale of S.F. Steam System | 0 |
| 26 | Hazardous Waste Management | 1,594 |
| 27 | CNG/Electric Vehicles | 219 |
| 28 | PHFU Additions | (11) |
| 29 | BOY 1992 | 677,251 |
| 30 | Common Plant Net Additions | 81,874 |
| 31 | Hazardous Waste Management | 367 |
| 32 | CNG/Electric Vehicles | 295 |
| 33 | BOY 1993 | 759,787 |
| 34 | Wtd Avg Common Plant Additions | 40,946 |
| 35 | Hazardous Waste Management | 166 |
| 36 | CNG/Electric Vehicles | 0 |
| 37 | PHFU Additions | 0 |
| 38 | Wtd Avg Common Plant, 1993 | 800,898 |
| 39 | TOTAL 1993 WTD AVERAGE GAS PLANT | 5,268,158 |



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

DEPRECIATION EXPENSE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Depreciation Expense | |
| 1 | Production | $179 |
| 2 | Underground Storage | 6,517 |
| 3 | Local Storage | 897 |
| 4 | Other | 0 |
| 5 | Transmission - Topock | 0 |
| 6 | Transmission - Canadian | 0 |
| 7 | Transmission - Other | 29,278 |
| 8 | Distribution | 148,976 |
| 9 | General | 1,496 |
| 10 | Subtotal | 187,343 |
| 11 | Net Additions | 0 |
| 12 | StanPac (6/7 Interest) | 665 |
| 13 | Common Utility Plant Allocation | 58,624 |
| 14 | TOTAL DEPRECIATION EXPENSE | 246,632 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

DEPRECIATION RESERVE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Depreciation Reserve, Beginning of Year | |
| 1 | Production | $869 |
| 2 | Underground Storage | 78,180 |
| 3 | Local Storage | 7,395 |
| 4 | Transmission | 467,008 |
| 5 | Distribution | 1,369,451 |
| 6 | General | 15,550 |
| 7 | 6/7 Interest in StanPac | 4,902 |
| 8 | Common Allocation | 291,156 |
| 9 | Total BOY Depreciation Reserve | 2,234,511 |
| | Depreciation Reserve, End of Year | |
| 10 | Production | 1,048 |
| 11 | Underground Storage | 84,274 |
| 12 | Local Storage | 8,292 |
| 13 | Transmission | 488,943 |
| 14 | Distribution | 1,497,692 |
| 15 | General | 17,004 |
| 16 | 6/7 Interest in StanPac | 5,550 |
| 17 | Common Allocation | 350,789 |
| 18 | Total EOY Depreciation Reserve | 2,453,592 |
| 19 | WEIGHTED AVERAGE DEPRECIATION RESERVE | 2,344,051 |

APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

WEIGHTED AVERAGE DEPRECIATED RATE BASE
(Thousands of 1993 dollars)

| Line No. | Description | ADOPTED |
|---|---|---|
| | Weighted Average Gas Plant | |
| 1 | Gas Plant | $5,268,158 |
| 2 | Total Weighted Average Plant | 5,268,158 |
| | Working Capital | |
| 3 | Materials and Supplies | 27,907 |
| 4 | Gas Line Pack | 7,505 |
| 5 | Working Cash | 32,900 |
| 6 | Total Working Capital | 68,312 |
| | Tax Reform Act Deferrals | |
| 7 | Deferred Capitalized Interest | 15,010 |
| 8 | Deferred Vacation | 11,837 |
| 9 | Deferred CIAC Tax Effects | 19,982 |
| 10 | Total Adjustments | 46,829 |
| | Less Deductions | |
| 11 | Customer Advances | 48,007 |
| 12 | Accumulated Deferred Taxes - Defense | 0 |
| 13 | Accumulated Deferred Taxes - ACRS | 192,731 |
| 14 | Accumulated Deferred Taxes - Other | (4,277) |
| 15 | Deferred ITC | 54,736 |
| 16 | Other | 0 |
| 17 | Total Deductions | 291,197 |
| 18 | Depreciation Reserve | 2,344,051 |
| 19 | TOTAL RATE BASE (a) | 2,748,051 |

(a) Includes NGV capital investment authorized in NGV D.91-07-018.



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APPENDIX D
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

NET-TO-GROSS MULTIPLIER

| Line No. | Description | (A) | (B) | (C=AxB) |
|---|---|---|---|---|
| 1 | Gross Operating Revenues | | | 1.000000 |
| 2 | Revenues From Customers | | | 0.835700 |
| 3 | Less: Uncollectibles | 0.003000 | 0.835700 | 0.002507 |
| 4 | | | | 0.997493 |
| 5 | Less: Franchise Requirements | 0.008770 | 0.833193 | 0.007307 |
| 6 | | | | 0.990186 |
| 7 | Less Super Fund Tax | 0.001200 | 0.990186 | 0.001188 |
| 8 | | | | 0.988998 |
| 9 | Less: State Income Tax | 0.093000 | 0.988998 | 0.091977 |
| 10 | | | | 0.898209 |
| 11 | Less: Federal Income Tax | 0.340000 | 0.988998 | 0.336259 |
| 12 | Net Operating Revenues | | | 0.560762 |
| 13 | Net-To-Gross Multiplier (Ln.13A / Ln.13B) | 1.000000 | 0.560762 | 1.783289 |

(End of Appendix D)

APPENDIX E - GAS DEPARTMENT'S ATTRITION CALCULATION
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

TEST YEAR 1993 -- O&M EXPENSE FOR ATTRITION CALCULATION
(Thousands of Dollars)

| Line No. | Description | TY 1993 | Transfer. | Adjusted TY 1993 |
|---|---|---|---|---|
| | | (A) | (B) | (C) |
| | Production | | | |
| 1 | Labor | $2,612 | | $2,612 |
| 2 | Non-Labor | 1,438 | | 1,438 |
| 3 | Other | 0 | | 0 |
| 4 | Total | 4,050 | | 4,050 |
| | Storage | | | |
| 5 | Labor | 1,259 | | 1,259 |
| 6 | Non-Labor | 6,980 | | 6,980 |
| 7 | Other | 198 | | 198 |
| 8 | Total | 8,437 | | 8,437 |
| | Transmission | | | |
| 9 | Labor | 24,833 | | 24,833 |
| 10 | Non-Labor | 20,783 | | 20,783 |
| 11 | Other | 0 | | 0 |
| 12 | Total | 45,616 | | 45,616 |
| | Distribution | | | |
| 13 | Labor | 87,879 | | 87,879 |
| 14 | Non-Labor | 47,414 | | 47,414 |
| 15 | Other | 0 | | 0 |
| 16 | Total | 135,293 | | 135,293 |
| | Customer Accounts | | | |
| 17 | Labor | 62,148 | | 62,148 |
| 18 | Non-Labor | 22,940 | | 22,940 |
| 19 | Other (Excl. Uncollectibles) | 7,380 | | 7,380 |
| 20 | Total | 92,468 | | 92,468 |
| | Demand-Side Management | | | |
| 21 | Labor | 10,491 | | 10,491 |
| 22 | Non-Labor | 51,671 | | 51,671 |
| 23 | Other | 0 | | 0 |
| 24 | Total | 62,162 | | 62,162 |
| | Administrative & General | | | |
| 25 | Labor | 51,273 | 0 | 51,273 |
| 26 | Wage Related | 12,638 | 0 | 12,638 |
| 27 | Non-Labor | 60,538 | 0 | 60,538 |
| 28 | Other (Excl. Franchise) | 57,471 | 0 | 57,471 |
| 29 | Medical | 27,652 | 0 | 27,652 |
| 30 | Total | 209,572 | 0 | 209,572 |
| | Labor Parity | | | |
| 31 | Labor | (6,728) | | (6,728) |
| 32 | Non-Labor | 0 | | 0 |
| 33 | Other | 0 | | 0 |
| 34 | Total | (6,728) | | (6,728) |
| 35 | Labor | 233,767 | 0 | 233,767 |
| 36 | Wage Related | 12,638 | 0 | 12,638 |
| 37 | Non-Labor | 211,764 | 0 | 211,764 |
| 38 | Other | 65,049 | 0 | 65,049 |
| 39 | Medical | 27,652 | 0 | 27,652 |
| 40 | TOTAL O&M EXPENSE | 550,870 | 0 | 550,870 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- O&M EXPENSE
(Thousands of Dollars)

| Line No. | Description | Labor & Wage-Rel. (A) | Non-Labor (B) | Other (C) | Medical (D) | TOTAL (E) |
|---|---|---|---|---|---|---|
| | **Test Year 1993** | | | | | |
| | Base (1993$) | $246,405 | $211,764 | $65,049 | $27,652 | $550,870 |
| | 1993 Adopted in GRC | 0.0500 | 0.0374 | 0.0000 | 0.1000 | |
| | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| | Base (1990$) (a) | 215,411 | 192,524 | 65,049 | 19,618 | 492,603 |
| | **Attrition Year 1994** | | | | | |
| | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| | 1993 (use recorded) | 0.0500 | 0.0374 | 0.0000 | 0.1000 | |
| | 1994 (use updated estimate) | 0.0324 | 0.0373 | 0.0000 | 0.0373 (a) | |
| | Base (1994$) | 254,389 | 219,663 | 65,049 | 28,684 | 567,784 |
| | 1994 Escalation | 7,984 | 7,899 | 0 | 1,031 | 16,914 |
| | 1994 Uncollectibles | 20 | 20 | 0 | 3 | 43 |
| | 1994 Franchise Requirement | 59 | 58 | 0 | 8 | 125 |
| | TOTAL 1994 ESCALATION | 8,063 | 7,977 | 0 | 1,042 | 17,081 |
| | **Attrition Year 1995** | | | | | |
| | 1991 Adopted in GRC | 0.0425 | 0.0315 | 0.0000 | 0.1270 | |
| | 1992 Adopted in GRC | 0.0450 | 0.0279 | 0.0000 | 0.1370 | |
| | 1993 (use recorded) | 0.0500 | 0.0374 | 0.0000 | 0.0373 (a) | |
| | 1994 (use recorded) | 0.0324 | 0.0373 | 0.0000 | 0.0354 (a) | |
| | 1995 (use updated estimate) | 0.0336 | 0.0354 | 0.0000 | | |
| | Base (1995$) | 262,936 | 227,439 | 65,049 | 29,699 | 585,123 |
| | 1995 Escalation | 8,547 | 7,776 | 0 | 1,015 | 17,339 |
| | 1995 Uncollectibles | 22 | 20 | 0 | 3 | 44 |
| | 1995 Franchise Requirement | 63 | 57 | 0 | 7 | 128 |
| | TOTAL 1995 ESCALATION | 8,632 | 7,853 | 0 | 1,025 | 17,511 |

(a) Use non-labor escalation rate for attrition year medical expense.

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

TEST YEAR 1993 -- RATE BASE FOR ATTRITION CALCULATION
(Thousands of Dollars)

| Line No. | Description | Full Year 1993 (A) | Wtd Avg 1993 (B) |
|---|---|---|---|
| 1 | Plant-in-Service: Beginning of Year | $5,061,928 | $5,061,928 |
| 2 | : Additions | 509,545 | 206,231 |
| 3 | Total Plant-in-Service | 5,571,473 | 5,268,158 |
| 4 | Plant Held for Future Use | 0 | 0 |
| 5 | Total Plant | 5,571,473 | 5,268,158 |
| 6 | Working Capital: Materials & Supplies | 27,907 | 27,907 |
| 7 | : Gas Line Pack | 7,505 | 7,505 |
| 8 | : Working Cash | 32,900 | 32,900 |
| 9 | Total Working Capital | 68,312 | 68,312 |
| 10 | TRA Adjustments: Deferred Cap. Interest | 17,121 | 15,010 |
| 11 | : Deferred Vacation Pay | 12,093 | 11,837 |
| 12 | : Deferred CIAC Tax | 21,289 | 19,982 |
| 13 | Total Adjustments | 50,503 | 46,829 |
| 14 | Customer Advances | 48,007 | 48,007 |
| 15 | Accumulated ACRS Deferred Taxes: BOY | 181,872 | 181,872 |
| 16 | : Additions | 25,876 | 10,859 |
| 17 | Total Accumulated ACRS Deferred Taxes | 207,748 | 192,731 |
| 18 | Accumulated Deferred: Investment Tax Credit | 53,847 | 54,736 |
| 19 | : Defense Facilities | 0 | 0 |
| 20 | : Other | (4,351) | (4,277) |
| 21 | Total Accumulated Deferred | 49,496 | 50,459 |
| 22 | Reserve: Beginning of Year | 2,234,511 | 2,234,511 |
| 23 | : Accrual | 246,632 | 123,316 |
| 24 | : Fossil Decommissioning | 0 | 0 |
| 25 | : Net Salvage | (27,608) | (13,804) |
| 26 | : Adjustment | | 29 |
| 27 | Total Reserve | 2,453,535 | 2,344,051 |
| 28 | TOTAL RATE BASE | 2,931,503 | 2,748,051 |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 -- RATE BASE
(Thousands of Dollars)

| Line No. | Description | Full Year 1994 (A) | Wtd Avg 1994 (B) | Wtd Avg 1994 Increase (C) |
|---|---|---|---|---|
| 1 | Plant-in-Service: Beg. of Year | $5,571,473 | $5,571,473 | $303,315 |
| 2 | : Additions | 432,504 | 175,049 | 175,049 |
| 3 | Total Plant-in-Service | 6,003,977 | 5,746,523 | 478,364 |
| 4 | Plant Held for Future Use | 0 | 0 | 0 |
| 5 | Total Plant | 6,003,977 | 5,746,523 | 478,364 |
| 6 | Working Capital: Matls & Supplies | 27,907 | 27,907 | 0 |
| 7 | : Gas Line Pack | 7,505 | 7,505 | 0 |
| 8 | : Working Cash | 32,900 | 32,900 | 0 |
| 9 | Total Working Capital | 68,312 | 68,312 | 0 |
| 10 | TRA Adjustments: Def. Cap. Interest | 21,117 | 18,882 | 3,872 |
| 11 | : Def. Vacation Pay | 12,506 | 12,299 | 462 |
| 12 | : Def. CIAC Tax | 24,000 | 22,645 | 2,663 |
| 13 | Total Adjustments | 57,623 | 53,826 | 6,997 |
| 14 | Customer Advances | 48,007 | 48,007 | 0 |
| 15 | Accum. ACRS Defer. Taxes: BOY | 207,748 | 207,748 | 25,876 |
| 16 | : Additions | 23,404 | 11,702 | 843 |
| 17 | Total Accum. ACRS Deferred Taxes | 231,152 | 219,450 | 26,719 |
| 18 | Accumulate Deferred: Investment Tax | 51,699 | 52,773 | (1,963) |
| 19 | : Defense Facil. | 0 | 0 | 0 |
| 20 | : Other | (4,277) | (4,277) | 0 |
| 21 | Total Accumulated Deferred | 47,422 | 48,496 | (1,963) |
| 22 | Reserve: Beginning of Year | 2,453,535 | 2,453,535 | 109,483 |
| 23 | : Accrual | 269,027 | 134,513 | 119,456 |
| 24 | : Fossil Decommissioning | 0 | 0 | 0 |
| 25 | : Net Salvage | (30,115) | (15,058) | 0 |
| 26 | : Adjustment | 0 | 0 | 0 |
| 27 | Total Reserve | 2,692,446 | 2,572,990 | 228,939 |
| 28 | TOTAL RATE BASE | 3,110,886 | 2,979,717 | 231,666 |



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## APPENDIX E
## PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

### AY 1995 -- RATE BASE
(Thousands of Dollars)

| Line No. | Description | Full Year 1995 (A) | Wtd Avg 1995 (B) | Wtd Avg 1995 Increase (C) |
|---|---|---|---|---|
| 1 | Plant-in-Service: Beg. of Year | $6,003,977 | $6,003,977 | $257,455 |
| 2 | : Additions | 455,678 | 184,429 | 184,429 |
| 3 | Total Plant-in-Service | 6,459,655 | 6,188,406 | 441,883 |
| 4 | Plant Held for Future Use | 0 | 0 | 0 |
| 5 | Total Plant | 6,459,655 | 6,188,406 | 441,883 |
| 6 | Working Capital: Matls & Supplies | 27,907 | 27,907 | 0 |
| 7 | : Gas Line Pack | 7,505 | 7,505 | 0 |
| 8 | : Working Cash | 32,900 | 32,900 | 0 |
| 9 | Total Working Capital | 68,312 | 68,312 | 0 |
| 10 | TRA Adjustments: Def. Cap. Interest | 23,181 | 22,334 | 3,452 |
| 11 | : Def. Vacation Pay | 12,914 | 12,710 | 411 |
| 12 | : Def. CIAC Tax | 27,000 | 25,500 | 2,855 |
| 13 | Total Adjustments | 63,095 | 60,544 | 6,718 |
| 14 | Customer Advances | 48,007 | 48,007 | 0 |
| 15 | Accum. ACRS Defer. Taxes: BOY | 231,152 | 231,152 | 23,404 |
| 16 | : Additions | 25,180 | 12,590 | 888 |
| 17 | Total Accum. ACRS Deferred Taxes | 256,331 | 243,741 | 24,292 |
| 18 | Accumulate Deferred: Investment Tax | 49,551 | 50,625 | (2,148) |
| 19 | : Defense Facil. | 0 | 0 | 0 |
| 20 | : Other | (4,277) | (4,277) | 0 |
| 21 | Total Accumulated Deferred | 45,274 | 46,348 | (2,148) |
| 22 | Reserve: Beginning of Year | 2,692,446 | 2,692,446 | 119,456 |
| 23 | : Accrual | 289,714 | 144,857 | 128,641 |
| 24 | : Fossil Decommissioning | 0 | 0 | 0 |
| 25 | : Net Salvage | (32,431) | (16,215) | 0 |
| 26 | : Adjustment | 0 | 0 | 0 |
| 27 | Total Reserve | 2,949,729 | 2,821,088 | 248,097 |
| 28 | TOTAL RATE BASE | 3,291,721 | 3,158,078 | 178,360 |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 1 of 3
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **Depreciation Expense** | | |
| 1 | 1993 Depreciation Expense | $246,632 | |
| 2 | 1993 Wtd Avg Plant-in-Service | 5,268,158 | |
| 3 | = System Average Depreciation Rate | 4.6816% | 4.6816% |
| 4 | x Plant-in-Service Weighted Average Increase | 478,364 | 441,883 |
| 5 | = Increase in Depreciation Expense | 22,395 | 20,687 |
| 6 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 7 | = Revenue Requirement | 39,937 | 36,891 |
| 8 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 9 | = CPUC Jurisdiction Revenue Requirement | 39,937 | 36,891 |
| | **Ad Valorem Taxes** | | |
| 10 | 1993 Ad Valorem Taxes | 29,837 | |
| 12 | 1993 Plant-in-Service, BOY | 5,571,473 | |
| 13 | = System Average Ad Valorem Taxes | 0.5355% | 0.5355% |
| 14 | x Current Attrition Year Additions | 432,504 | 455,678 |
| 15 | = Increase in Ad Valorem Taxes | 2,316 | 2,440 |
| 16 | x Uncoll. & Franchise Net-to-Gross Multiplier | 1.009911 | 1.009911 |
| 17 | = Revenue Requirement | 2,339 | 2,464 |
| 18 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 19 | = CPUC Jurisdiction Revenue Requirement | 2,339 | 2,464 |
| | **CCFT Depreciation** | | |
| 20 | 1993 CCFT Depreciation | 212,622 | |
| 21 | 1993 Plant-in-Service, BOY | 5,571,473 | |
| 22 | = System Average CCFT Depreciation Rate | 3.8163% | 3.8163% |
| 23 | x Current Attrition Year Additions | 432,504 | 455,678 |
| 24 | = Increase in CCFT Depreciation Expense | 16,506 | 17,390 |
| 25 | x -CCFT Rate | -9.30% | -9.30% |
| 26 | = California Corporate Franchise Tax | (1,535) | (1,617) |
| 27 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 28 | = Revenue Requirement | (2,737) | (2,884) |
| 29 | California Corporate Franchise Tax | (1,535) | (1,617) |
| 30 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 31 | = CPUC State Income Taxes | (1,535) | (1,617) |
| 32 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 33 | = CPUC Jurisdiction Revenue Requirement | (2,737) | (2,884) |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 2 of 3
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **FIT Depreciation** | | |
| 1 | 1993 FIT Depreciaton | $180,705 | |
| 2 | 1993 Plant-in-Service, BOY | 5,571,473 | |
| 3 | = System Average FIT Depreciation Rate | 3.2434% | 3.2434% |
| 4 | x Current Attrition Year Additions | 432,504 | 455,678 |
| 5 | = Increase in FIT Depreciation Expense | 14,028 | 14,779 |
| 6 | x -FIT Rate | -34.00% | -34.00% |
| 7 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 8 | = Revenue Requirement | (8,505) | (8,961) |
| 9 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 10 | = CPUC Jurisdiction Revenue Requirement | (8,505) | (8,961) |
| | | ========== | ========== |
| 11 | Net Increase in FIT Depreciation Expense | 14,028 | 14,779 |
| 12 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 13 | x Super Fund Tax Net-to-Gross Multiplier | 1.011125 | 1.011125 |
| 14 | = Super Fund Tax Effect on Fed. Tax Dep. Incr | (17) | (18) |
| 15 | Total Revenue Requirement | (8,522) | (8,979) |
| 16 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 17 | = Total CPUC Jurisdiction Revenue Requirement | (8,522) | (8,979) |
| | | ========== | ========== |
| | **Prior Year's CCFT Deductible for FIT** | | |
| 18 | Prior Year's Revenue Requirement (Excl. Super Fund Tax Effect) | | |
| 19 | + Depreciation | | 39,937 |
| 20 | + CCFT Depreciation | | (2,405) |
| 21 | + FIT Depreciation | | (7,292) |
| 22 | + Rate Base: Preferred Stock | | 1,983 |
| 23 | + : Common Stock Equity | | 22,970 |
| 24 | + CCFT | | 2,212 |
| 25 | = Prior Year's Revenue Requirement | | 57,405 |
| 26 | x CCFT Cumulative Component | | 0.091977 |
| 27 | = CCFT Increase | | 5,280 |
| 28 | + Prior Year's CCFT for CCFT Depreciation Expense | | (1,349) |
| 29 | = Total CCFT Increase | | 3,931 |
| 30 | Prior Year's CCFT Subtotal | 32,148 | 36,079 |
| 31 | - Prior Year's CCFT Deductible for FIT | 35,796 | 32,148 |
| 32 | = Increase in CCFT Deduction for FIT | (3,648) | 3,931 |
| 33 | x -FIT Rate | -34.00% | -34.00% |
| 34 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 35 | = Revenue Requirement (FIT) | 2,212 | (2,383) |
| | | ========== | ========== |
| 36 | Net Increase in CCFT Deductible for FIT | (3,648) | 3,931 |
| 37 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 38 | x Super Fund Tax Net-to-Gross Multiplier | 1.011125 | 1.011125 |
| 39 | = Super Fund Tax Effect on Incr. in Deduction | 4 | (5) |
| 40 | Total Revenue Requirement (FIT and Super Fund Tax) | 2,216 | (2,388) |
| | | ========== | ========== |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CAPITAL-RELATED ITEMS, 3 of 3
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | RATE BASE | | |
| 1 | Prior Year's Weighted Average Rate Base | 2,748,051 | 2,979,717 |
| 2 | Current Attrition Year's Wtd Avg Rate Base | 2,979,717 | 3,158,078 |
| | LONG-TERM DEBT | | |
| 3 | Prior Year's Return on Debt | 8.61% | 8.61% |
| 4 | x Prior Year's Debt Capitalization | 47.50% | 47.50% |
| 5 | = Prior Year's Weighted Cost of Debt | 4.09% | 4.09% |
| 6 | Change in Weighted Average Rate Base | 231,666 | 178,360 |
| 7 | x Prior Year's Weighted Average Cost of Debt | 4.09% | 4.09% |
| 8 | = Change in Weighted Cost of Debt | 9,475 | 7,295 |
| 9 | x Uncoll. & Franchise Net-to-Gross Multiplier | 1.009911 | 1.009911 |
| 10 | = Revenue Requirement | 9,569 | 7,367 |
| 11 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 12 | = CPUC Jurisdiction Revenue Requirement | 9,569 | 7,367 |
| | PREFERRED STOCK | | |
| 13 | Prior Year's Return on Preferred Stock | 8.35% | 8.35% |
| 14 | x Prior Year's Preferred Stock Capitalization | 5.75% | 5.75% |
| 15 | = Prior Year's Wtd Cost of Preferred Stock | 0.48% | 0.48% |
| 16 | Change in Weighted Average Rate Base | 231,666 | 178,360 |
| 17 | x Prior Year's Wtd Cost of Preferred Stock | 0.48% | 0.48% |
| 18 | = Change in Weighted Cost of Preferred Stock | 1,112 | 856 |
| 19 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 20 | = Increase in Revenue Requirement | 1,983 | 1,527 |
| 21 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 22 | = CPUC Jurisdiction Revenue Requirement | 1,983 | 1,527 |
| | COMMON EQUITY | | |
| 23 | Prior Year's Return on Common Equity | 11.90% | 11.90% |
| 24 | x Prior Year's Common Equity Capitalization | 46.75% | 46.75% |
| 25 | = Prior Year's Weighted Cost of Common Equity | 5.56% | 5.56% |
| 26 | Change in Weighted Average Rate Base | 231,666 | 178,360 |
| 27 | x Prior Year's Weighted Cost of Common Equity | 5.56% | 5.56% |
| 28 | = Change in Weighted Cost of Common Equity | 12,881 | 9,917 |
| 29 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 30 | = Increase in Revenue Requirement | 22,970 | 17,685 |
| 31 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 32 | = CPUC Jurisdiction Revenue Requirement | 22,970 | 17,685 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Test Year 1993

AY 1994 & 1995 -- FINANCIAL COMPONENTS
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **RATE BASE** | | |
| 1 | Weighted Average Rate Base | $2,979,717 | $3,158,078 |
| | **LONG-TERM DEBT** | | |
| 2 | Prior Year's Return on Debt | 8.61% | |
| 3 | x Prior Year's Debt Capitalization | 47.50% | |
| 4 | x Uncoll.& Franchise Net-to-Gross Multiplier | 1.009911 | |
| 5 | = Prior Year's Gross Weighted Cost of Debt | 0.041305 | |
| 6 | Current Attrition Year's Return on Debt | 8.61% | 8.61% |
| 7 | x Current AY's Debt Capitalization | 47.50% | 47.50% |
| 8 | x Uncoll.& Franchise Net-to-Gross Multiplier | 1.009911 | 1.009911 |
| 9 | = AY Gross Weighted Cost of Debt | 0.041305 | 0.041305 |
| 10 | Change in Gross Weighted Cost of Debt | 0.000000 | 0.000000 |
| 11 | x Weighted Average Rate Base | 2,979,717 | 3,158,078 |
| 12 | = Change in Revenue Requirement | 0 | 0 |
| 13 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 14 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |
| | **PREFERRED STOCK** | | |
| 15 | Prior Year's Return on Preferred Stock | 8.35% | |
| 16 | x Prior Year's Pref. Stock Capitalization | 5.75% | |
| 17 | x Net-to-Gross Mulitiplier | 1.783289 | |
| 18 | = Prior Year's Gross Wtd Cost of Pref. Stock | 0.008560 | |
| 19 | Current Attrition Year's Return on Pref. Stock | 8.35% | 8.35% |
| 20 | x Current AY's Pref. Stock Capitalization | 5.75% | 5.75% |
| 21 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 22 | = AY Gross Weighted Cost of Preferred Stock | 0.008560 | 0.008560 |
| 23 | Change in Gross Wtd Cost of Preferred Stock | 0.000000 | 0.000000 |
| 24 | x Weighted Average Rate Base | 2,979,717 | 3,158,078 |
| 25 | = Change in Revenue Requirement | 0 | 0 |
| 26 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 27 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |
| | **COMMON EQUITY** | | |
| 28 | Prior Year's Return on Common Equity | 11.90% | |
| 29 | x Prior Year's Common Equity Capitalization | 46.75% | |
| 30 | x Net-to-Gross Mulitiplier | 1.783289 | |
| 31 | = Prior Yr's Gross Wtd Cost of Common Equity | 0.099151 | |
| 32 | Current Attrition Yr's Return on Common Equity | 11.90% | 11.90% |
| 33 | x Current AY's Common Equity Capitalization | 46.75% | 46.75% |
| 34 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 35 | = AY Gross Weighted Cost of Common Equity | 0.099151 | 0.099151 |
| 36 | Change in Gross Wtd Cost of Common Equity | 0.000000 | 0.000000 |
| 37 | x Weighted Average Rate Base | 2,979,717 | 3,158,078 |
| 38 | = Change in Revenue Requirement | 0 | 0 |
| 39 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 40 | = CPUC Jurisdiction Revenue Requirement | 0 | 0 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- OTHER ITEMS & ADJUSTMENTS
(Thousands of Dollars)

| Line No. | Description | 1994 (A) | 1995 (B) |
|---|---|---|---|
| | **State ADR Tax Depreciation Adjustment** | | |
| 1 | State ADR Tax Depreciation Adjustment | ($2,000) | ($2,000) |
| 2 | x -CCFT Rate | -9.30% | -9.30% |
| 3 | = CCFT | 186 | 186 |
| 4 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 5 | = Revenue Requirement | 332 | 332 |
| 6 | California Corporate Franchise Tax | 186 | 186 |
| 7 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 8 | = CPUC Jurisdiction CCFT | 186 | 186 |
| 9 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 10 | = CPUC Jurisdiction Revenue Requirement | 332 | 332 |
| | **Federal ADR Tax Depreciation Adjustment** | | |
| 11 | Federal ADR Tax Depreciation Adjustment | (2,000) | (2,000) |
| 12 | x -FIT Rate | -34.00% | -34.00% |
| 13 | x Net-to-Gross Mulitiplier | 1.783289 | 1.783289 |
| 14 | = Revenue Requirement | 1,213 | 1,213 |
| 15 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 16 | = CPUC Jurisdiction Revenue Requirement | 1,213 | 1,213 |
| 17 | Federal ADR Tax Depreciation Adjustment | (2,000) | (2,000) |
| 18 | x -Super Fund Tax Rate | -0.12% | -0.12% |
| 19 | x Super Fund Tax Net-to-Gross Multiplier | 1.011125 | 1.011125 |
| 20 | = Super Fund Tax Effect on Change in FIT Dep. | 2 | 2 |
| 21 | Total Revenue Requirement | 1,215 | 1,215 |
| 22 | x CPUC Allocation Factor | 1.0000000 | 1.0000000 |
| 23 | = Total CPUC Jurisdiction Revenue Requirement | 1,215 | 1,215 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 & 1995 -- CHANGE IN REVENUE REQUIREMENT
(Thousands of Dollars)

| Line No. | Description | Attrition Year 1994 (A) | Attrition Year 1995 (B) |
|---|---|---|---|
| | Operating & Maintenance Expense | | |
| 1 | Labor Escalation | $8,063 | $8,632 |
| 2 | Non-Labor Escalation | 7,977 | 7,853 |
| 3 | Medical Escalation | 1,042 | 1,025 |
| 4 | Total Operation & Maintenance Expense | 17,082 | 17,510 |
| | Capital-Related Items | | |
| 5 | Book Depreciation Expense | 39,937 | 36,891 |
| 6 | Ad Valorem Taxes | 2,339 | 2,464 |
| 7 | Prior Year's CCFT | 2,216 | (2,388) |
| 8 | State Tax Depreciation | (2,405) | (2,552) |
| 9 | Federal Tax Depreciation | (7,307) | (7,764) |
| 10 | Rate Base: Debt Cost | 9,569 | 7,367 |
| 11 | : Preferred Stock Cost | 1,983 | 1,527 |
| 12 | : Common Equity Cost | 22,970 | 17,685 |
| 13 | Total Capital-Related Items | 69,302 | 53,230 |
| | Financial Components | | |
| 14 | Debt Cost | 0 | 0 |
| 15 | Preferred Stock Cost | 0 | 0 |
| 16 | Common Equity Cost | 0 | 0 |
| 17 | Total Financial Components | 0 | 0 |
| | Other Items | | |
| 18 | Other | 0 | 0 |
| 19 | Total Other Items | 0 | 0 |
| 20 | SUBTOTAL | 86,384 | 70,740 |
| | Special Projects | | |
| 21 | NOx Reduction | 0 | 0 |
| 22 | TOTAL CHANGE IN REVENUE REQUIREMENT | 86,384 | 70,740 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 -- RESULTS OF OPERATIONS
(Thousands of Dollars)

| Line No. | Description | TY 1993 Adopted (A) | 1994 Increase (B) | Attrition Year 1994 (C=A+B) |
|---|---|---|---|---|
| | Operating Revenues | | | |
| 1 | Revenues | $1,287,311 | $86,383 | $1,373,693 |
| 2 | Total Operating Revenues | 1,287,311 | 86,383 | 1,373,693 |
| | Operating Expenses | | | |
| 3 | Natural Gas Used by Gas Department | 0 | 0 | 0 |
| 4 | Storage | 7,645 | 0 | 7,645 |
| 5 | Production | 3,590 | 0 | 3,590 |
| 6 | Transmission | 40,604 | 0 | 40,604 |
| 7 | Distribution | 119,932 | 0 | 119,932 |
| 8 | Customer Accounts | 82,566 | 0 | 82,566 |
| 9 | Uncollectibles | 3,227 | 217 | 3,444 |
| 10 | Demand-Side Management | 56,149 | 0 | 56,149 |
| 11 | Administrative & General | 187,999 | 0 | 187,999 |
| 12 | Franchise Requirements | 9,407 | 631 | 10,038 |
| 13 | Project Amortization | 351 | 0 | 351 |
| 14 | Adjustments | 0 | 0 | 0 |
| 15 | Subtotal (1990 Dollars) | 511,470 | 848 | 512,318 |
| 16 | Labor Adjustment To Parity | (6,728) | 0 | (6,728) |
| 17 | Labor Escalation Amount | 31,844 | 7,984 | 39,828 |
| 18 | Non-Labor Escalation Amount | 27,269 | 8,930 | 36,199 |
| 19 | Subtotal (1993 Dollars) | 563,855 | 17,762 | 581,617 |
| 20 | Super Fund Tax Increase | 85 | 58 | 143 |
| 21 | Depreciation | 246,632 | 22,395 | 269,027 |
| 22 | Taxes Other Than On Income | 54,803 | 2,316 | 57,119 |
| 23 | CA Corporation Franchise Tax | 31,058 | 3,931 | 34,989 |
| 24 | Federal Income Tax | 112,500 | 16,453 | 128,953 |
| 25 | Total Operating Expenses | 1,008,933 | 62,915 | 1,071,848 |
| 26 | Net Operating Revenues | 278,378 | 23,468 | 301,845 |
| 27 | Net Return on Rate Base | 278,378 | 23,468 | 301,845 |
| 28 | Adjusted Rate Base | 2,748,051 | 231,666 | 2,979,717 |
| 29 | Rate of Return | 10.13% | 10.13% | 10.13% |

| | |
|---|---|
| Currently Adopted ROR | 10.13% |
| Net-to-Gross | 1.78329 |
| Additional Revenues | 0 |
| Revenues | 1,373,693 |
| New Revenue Estimate | 1,373,693 |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1994 -- TAXES ON INCOME
(Thousands of Dollars)

| Line No. | Description | TY 1993 Adopted | 1994 Increase | Attrition Year 1994 |
|---|---|---|---|---|
| | | (A) | (B) | (C=A+B) |
| | **California Corporation Franchise Tax** | | | |
| 1 | Operating Revenues | $1,287,311 | $86,383 | $1,373,693 |
| 2 | Operating Expenses | 563,855 | 17,762 | 581,617 |
| 3 | Super Fund Tax Increase | 85 | 58 | 143 |
| 4 | Taxes Other Than On Income | 54,803 | 2,316 | 57,119 |
| 5 | Income Tax Adjustments | 322,890 | 23,981 | 346,871 |
| 7 | California Taxable Income | 345,678 | 42,266 | 387,944 |
| 8 | CCFT Rate | 9.30% | 9.30% | 9.30% |
| 9 | CCFT | 32,148 | 3,931 | 36,079 |
| 10 | Defense Facilities Credit | 0 | 0 | 0 |
| 11 | Deferred Taxes - Other | 0 | 0 | 0 |
| 12 | Deferred Taxes - Interest | (972) | 0 | (972) |
| 13 | Deferred Taxes - Vacation | (118) | 0 | (118) |
| 14 | Adjustment | 0 | 0 | 0 |
| 15 | Adjustment | 0 | 0 | 0 |
| 16 | Total CCFT | 31,058 | 3,931 | 34,989 |
| | **Federal Income Tax** | | | |
| 17 | Operating Revenues | 1,287,311 | 86,383 | 1,373,693 |
| 18 | Operating Expenses | 563,855 | 17,762 | 581,617 |
| 19 | Super Fund Tax Increase | 85 | 58 | 143 |
| 20 | Taxes Other Than On Income | 54,803 | 2,316 | 57,119 |
| 21 | Prior Year's CCFT | 35,796 | (3,648) | 32,148 |
| 22 | Income Tax Adjustments | 289,607 | 21,503 | 311,110 |
| 23 | Federal Taxable Income | 343,165 | 48,392 | 391,557 |
| 24 | FIT Rate | 34.00% | 34.00% | 34.00% |
| 25 | Federal Income Tax | 116,676 | 16,453 | 133,129 |
| 26 | Flowback of Excess Deferred Tax | (560) | 0 | (560) |
| 27 | Defense Facilities Credit | 0 | 0 | 0 |
| 28 | Deferred Taxes - ACRS/MACRS | 0 | 0 | 0 |
| 29 | Deferred Taxes - Interest & Vacation | (3,616) | 0 | (3,616) |
| 30 | Amortization of ITC | 0 | 0 | 0 |
| 31 | Total FIT | 112,500 | 16,453 | 128,953 |

APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1995 -- RESULTS OF OPERATIONS
(Thousands of Dollars)

| Line No. | Description | Attrition Year 1994 (A) | 1995 Increase (B) | Attrition Year 1995 (C=A+B) |
|---|---|---|---|---|
| | **Operating Revenues** | | | |
| 1 | Revenues | $1,373,693 | $70,742 | $1,444,435 |
| 2 | Total Operating Revenues | 1,373,693 | 70,742 | 1,444,435 |
| | **Operating Expenses** | | | |
| 3 | Natural Gas Used by Gas Department | 0 | 0 | 0 |
| 4 | Storage | 7,645 | 0 | 7,645 |
| 5 | Production | 3,590 | 0 | 3,590 |
| 6 | Transmission | 40,604 | 0 | 40,604 |
| 7 | Distribution | 119,932 | 0 | 119,932 |
| 8 | Customer Accounts | 82,566 | 0 | 82,566 |
| 9 | Uncollectibles | 3,444 | 177 | 3,621 |
| 10 | Demand-Side Management | 56,149 | 0 | 56,149 |
| 11 | Administrative & General | 187,999 | 0 | 187,999 |
| 12 | Franchise Requirements | 10,038 | 518 | 10,556 |
| 13 | Project Amortization | 351 | 0 | 351 |
| 14 | Adjustments | 0 | 0 | 0 |
| 15 | Subtotal (1990 Dollars) | 512,318 | 696 | 513,013 |
| 16 | Labor Adjustment To Parity | (6,728) | 0 | (6,728) |
| 17 | Labor Escalation Amount | 39,828 | 8,547 | 48,375 |
| 18 | Non-Labor Escalation Amount | 36,199 | 8,791 | 44,990 |
| 19 | Subtotal (1993 Dollars) | 581,617 | 18,034 | 599,651 |
| 20 | Super Fund Tax Increase | 143 | 32 | 175 |
| 21 | Depreciation | 269,027 | 20,687 | 289,714 |
| 22 | Taxes Other Than On Income | 57,119 | 2,440 | 59,559 |
| 23 | CA Corporation Franchise Tax | 34,989 | 2,562 | 37,551 |
| 24 | Federal Income Tax | 128,953 | 8,918 | 137,871 |
| 25 | Total Operating Expenses | 1,071,848 | 52,674 | 1,124,522 |
| 26 | Net Operating Revenues | 301,845 | 18,068 | 319,913 |
| 27 | Net Return on Rate Base | 301,845 | 18,068 | 319,913 |
| 28 | Adjusted Rate Base | 2,979,717 | 178,360 | 3,158,078 |
| 29 | Rate of Return | 10.13% | 10.13% | 10.13% |

| | |
|---|---|
| Currently Adopted ROR | 10.13% |
| Net-to-Gross | 1.78329 |
| Additional Revenues | 0 |
| Revenues | 1,444,435 |
| New Revenue Estimate | 1,444,435 |



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APPENDIX E
PACIFIC GAS AND ELECTRIC COMPANY
Gas Department, Attrition Years 1994 and 1995

AY 1995 -- TAXES ON INCOME
(Thousands of Dollars)

| Line No. | Description | TY 1994 Adopted (A) | 1995 Increase (B) | Attrition Year 1995 (C=A+B) |
|---|---|---|---|---|
| | California Corporation Franchise Tax | | | |
| 1 | Operating Revenues | $1,373,693 | $70,742 | $1,444,435 |
| 2 | Operating Expenses | 581,617 | 18,034 | 599,651 |
| 3 | Super Fund Tax Increase | 143 | 32 | 175 |
| 4 | Taxes Other Than On Income | 57,119 | 2,440 | 59,559 |
| 5 | Income Tax Adjustments | 346,871 | 22,685 | 369,555 |
| 7 | California Taxable Income | 387,944 | 27,550 | 415,494 |
| 8 | CCFT Rate | 9.30% | 9.30% | 9.30% |
| 9 | CCFT | 36,079 | 2,562 | 38,641 |
| 10 | Defense Facilities Credit | 0 | 0 | 0 |
| 11 | Deferred Taxes - Other | 0 | 0 | 0 |
| 12 | Deferred Taxes - Interest | (972) | 0 | (972) |
| 13 | Deferred Taxes - Vacation | (118) | 0 | (118) |
| 14 | Adjustment | 0 | 0 | 0 |
| 15 | Adjustment | 0 | 0 | 0 |
| 16 | Total CCFT | 34,989 | 2,562 | 37,551 |
| | Federal Income Tax | | | |
| 17 | Operating Revenues | 1,373,693 | 70,742 | 1,444,435 |
| 18 | Operating Expenses | 581,617 | 18,034 | 599,651 |
| 19 | Super Fund Tax Increase | 143 | 32 | 175 |
| 20 | Taxes Other Than On Income | 57,119 | 2,440 | 59,559 |
| 21 | Prior Year's CCFT | 32,148 | 3,931 | 36,079 |
| 22 | Income Tax Adjustments | 311,110 | 20,074 | 331,184 |
| 23 | Federal Taxable Income | 391,557 | 26,230 | 417,786 |
| 24 | FIT Rate | 34.00% | 34.00% | 34.00% |
| 25 | Federal Income Tax | 133,129 | 8,918 | 142,047 |
| 26 | Flowback of Excess Deferred Tax | (560) | 0 | (560) |
| 27 | Defense Facilities Credit | 0 | 0 | 0 |
| 28 | Deferred Taxes - ACRS/MACRS | 0 | 0 | 0 |
| 29 | Deferred Taxes - Interest & Vacation | (3,616) | 0 | (3,616) |
| 30 | Amortization of ITC | 0 | 0 | 0 |
| 31 | Total FIT | 128,953 | 8,918 | 137,871 |

(End of Appendix E)

# APPENDIX F
# PACIFIC GAS & ELECTRIC COMPANY
# 1993 GENERAL RATE CASE

## Appendix F - Electric Marginal Costs

# APPENDIX F
# PACIFIC GAS & ELECTRIC COMPANY
# 1993 GENERAL RATE CASE
# SUMMARY OF MARGINAL ENERGY COSTS

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| Line No. | | SUMMER PEAK | SUMMER PART PEAK | SUMMER OFF PEAK | WINTER PART PEAK | WINTER OFF PEAK | ANNUAL |
|---|---|---|---|---|---|---|---|
| | GENERATION | | | | | | |
| 1 | ENERGY (includes O&M, geothermal adder, and emissions adder) | 3.93 | 3.27 | 3.02 | 4.41 | 3.61 | 3.58 |
| 2 | CASH WORKING CAPITAL (line 1*2.12%) | 0.0833 | 0.0693 | 0.0640 | 0.0935 | 0.0765 | 0.0759 |
| 3 | REV. REQ. FOR CASH WORKING CAPITAL (line 2*15.52%) | 0.0129 | 0.0108 | 0.0099 | 0.0145 | 0.0119 | 0.0118 |
| 4 | MARGINAL ENERGY COST (line 1 + line 3) | 3.9429 | 3.2808 | 3.0299 | 4.4245 | 3.6219 | 3.5918 |
| 5 | MARG. EGY COST INCLUDING FF&U (line 4*1.00942) | 3.9801 | 3.3117 | 3.0585 | 4.4662 | 3.6560 | 3.6256 |
| | TRANSMISSION | | | | | | |
| 6 | TRANSMISSION LOSS FACTOR | 1.0240 | 1.0103 | 1.0124 | 1.0115 | 1.0165 | 1.0165 |
| 7 | MARG. EGY COST WITH LINE LOSSES (line 5*line 6) | 4.0756 | 3.3458 | 3.0964 | 4.5176 | 3.7163 | 3.6854 |
| | PRIMARY DIST. | | | | | | |
| 8 | PRIMARY LOSS FACTOR | 1.0330 | 1.0320 | 1.0240 | 1.0270 | 1.0230 | 1.0230 |
| 9 | MARG. EGY COST + LINE LOSSES (line 7 * line 8) | 4.2101 | 3.4528 | 3.1707 | 4.6395 | 3.8018 | 3.7702 |
| | SECONDARY DIST. | | | | | | |
| 10 | SECONDARY LOSS FAC | 1.0484 | 1.0291 | 1.0195 | 1.0487 | 1.0196 | 1.0196 |
| 11 | MARG. EGY COST + LINE LOSSES (line 9 * line 10) | 4.4139 | 3.5533 | 3.2325 | 4.8655 | 3.8763 | 3.8441 |



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# APPENDIX F
## PACIFIC GAS & ELECTRIC COMPANY
## 1993 GENERAL RATE CASE
## MARGINAL GENERATION CAPACITY COSTS
(used for revenue allocation)

| Year | Marginal Capacity Costs ($/kW year) | Combustion Turbine Escalation Rate | Marginal Capacity Costs (1993 $/kW year) |
|---|---|---|---|
| 1993 | 5.24 | | 5.24 |
| 1994 | 5.42 | 1.036 | 5.23 |
| 1995 | 5.31 | 1.036 | 4.95 |
| 1996 | 10.75 | 1.037 | 9.66 |
| 1997 | 14.79 | 1.051 | 12.64 |
| 1998 | 18.70 | 1.054 | 15.17 |
| Six Year Average | | | 8.81 |



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# APPENDIX F
## PACIFIC GAS & ELECTRIC COMPANY
## 1993 General Rate Case
## AREA TRANSMISSION MARGINAL CAPACITY COSTS

| | Annualized Cost 1993 $ per kW Year |
|---|---|
| **DIVISION LEVEL PROJECTS:** | |
| Project 1: SF Near Term Reinforcement | 9.67 |
| Project 2: SF/East Bay Reinforcement | 70.77 |
| Project 3: Metcalf-Monta Vista Reinforcement | 13.80 |
| Project 4: Fresno Area Reinforcement | 28.22 |
| **AREA TRANSMISSION PROJECTS:** | |
| 1. Fulton Junction - Fulton Trans Relief | 72.46 |
| 2. Fulton - Santa Rosa 115 kV Relief | 1.51 |
| 3. Cotati Substation 115 kV Conversion | 19.78 |
| 4. Ignacio - Sausalito 60 kV Reconductoring | 39.25 |
| 5. Glenn Transformer Bank Increase | 52.74 |
| 6. Connect New Chico Substation | 2.42 |
| 7. Colgate 115 kV Transmission Relief | 2.42 |
| 8. Table Mountain 115 kV Transmission Line | 14.16 |
| 9. Rio Oso - Vaca Dixon 115 kV Transmission Line | 0.41 |
| 10. Atlantic Area Transmission Development | 5.33 |
| 11. Yolo Area Transmission Relief | 9.50 |
| 12. Reconductor Hillsdale Jct. - Half Moon Bay | 78.35 |
| 13. Install 230/60 kV Capability at Las Positas | 6.05 |
| 14. Concord Area 115 kV Transmission Relief | 4.48 |
| 15. Newark - Magnesium 115 kV Trans. Reinforcement | 20.92 |
| 16. Reconductor Newark - Metcalf 115 kV Line | 7.74 |
| 17. Metcalf El Patio 115 kV Trans. Reinforcement | 0.47 |
| 18. Santa Clara Transmission Service | 0.46 |
| 19. Metcalf 230/115 kV Transformer Bank Increase | 2.12 |
| 20. Clovis - Sanger 115 kV Emergency Relief | 3.57 |
| 21. Westpark - Magunden 115 kV Relief | 2.14 |

# APPENDIX F
## PACIFIC GAS & ELECTRIC COMPANY
### 1993 General Rate Case
### PRIMARY DISTRIBUTION MARGINAL CAPACITY COSTS BY DIVISION

| DIVISION | Annualized Cost 1993 $ per kW Year |
|---|---|
| East Bay | 53.50 |
| Golden Gate | 50.50 |
| North Bay | 61.77 |
| Sacramento | 48.19 |
| San Jose | 67.32 |
| De Sabla | 67.22 |
| Colgate | 77.68 |
| Shasta | 83.16 |
| Drum | 80.89 |
| Stockton | 65.17 |
| Coast Valley | 58.69 |
| Humboldt | 76.37 |
| San Joaquin | 44.95 |

# APPENDIX F
## PACIFIC GAS & ELECTRIC COMPANY
## 1993 General Rate Case
## SECONDARY DISTRIBUTION MARGINAL CAPACITY COSTS BY DIVISION

| DIVISION | Annualized Cost 1993 $ per kW Year |
|---|---|
| East Bay | 0.79 |
| Golden Gate | 0.92 |
| North Bay | 1.99 |
| Sacramento | 0.49 |
| San Jose | 1.26 |
| De Sabla | 1.59 |
| Colgate | 2.16 |
| Shasta | 2.67 |
| Drum | 0.74 |
| Stockton | 0.69 |
| Coast Valley | 1.65 |
| Humboldt | 1.80 |
| San Joaquin | 1.19 |

# APPENDIX F
## PACIFIC GAS AND ELECTRIC COMPANY
## 1993 GENERAL RATE CASE
## MARGINAL CUSTOMER COSTS
(1993 $ per customer year)

| Customer Class | East Bay | Golden Gate | Mission Trail | Redwood | Sacramento Valley | San Joaquin Valley |
|---|---|---|---|---|---|---|
| Residential | 106.89 | 88.24 | 134.31 | 132.69 | 140.02 | 120.67 |
| Small Light & Power | 258.32 | 203.44 | 195.57 | 183.53 | 197.42 | 188.00 |
| Medium Light & Power: Secondary | 1,082.21 | 1,587.32 | 1,279.42 | 1,308.88 | 1,277.92 | 1,228.94 |
| Medium Light & Power: Primary | 1,737.68 | 1,335.69 | 1,315.85 | 1,127.51 | 1,396.47 | 1,186.07 |
| Large Light & Power (E-19): Secondary | 2,058.14 | 2,658.77 | 2,658.77 | 2,658.77 | 2,658.77 | 2,658.88 |
| Large Light & Power (E-19): Primary | 1,272.48 | 1,434.78 | 1,239.83 | 1,239.83 | 1,239.83 | 1,453.75 |
| E-20: Primary | 10,020.31 | 10,363.05 | 10,162.45 | 10,299.28 | 10,165.51 | 10,331.50 |
| E-20: Secondary | 12,489.44 | 12,989.41 | 12,476.93 | 12,477.05 | 12,495.87 | 12,459.36 |
| E-19 and E-20: Transmission | 13,503.62 | 13,503.62 | 13,503.62 | 13,503.62 | 13,503.62 | 13,503.62 |
| Agriculture - Ag A | 465.63 | 310.52 | 347.11 | 426.93 | 351.27 | 349.22 |
| Agriculture - Ag B | 628.98 | 310.63 | 432.25 | 610.52 | 610.77 | 901.76 |
| Streetlighting | 198.19 | 198.19 | 198.19 | 198.19 | 198.19 | 198.19 |

# APPENDIX F
## PACIFIC GAS AND ELECTRIC COMPANY
## 1993 GENERAL RATE CASE
## MARGINAL CUSTOMER COSTS USED FOR REVENUE ALLOCATION
(1993 $ per customer year)

| Class | $/Customer Year |
|---|---|
| Residential | $68.66 |
| Small Light and Power | $157.20 |
| Medium Light and Power: Secondary | $877.33 |
| Medium Light and Power: Primary | $846.46 |
| E-19: Secondary | $2,902.32 |
| E-19: Primary | $676.46 |
| E-20: Secondary | $10,245.16 |
| E-20: Primary | $9,749.47 |
| E-19 and E-20: Transmission | $14,416.27 |
| Agriculture - A | $246.71 |
| Agriculture - B & C | $353.98 |
| Streetlighting | $123.14 |

# APPENDIX F
## PACIFIC GAS & ELECTRIC COMPANY
## 1993 GENERAL RATE CASE
## COMBUSTION TURBINE COST
(as agreed to and recorded in Exhibit 231)
1993 Dollars

| Line No. | | | | |
|---|---|---|---|---|
| | Long Term Investment | | | |
| 1 | Installation (on-site) | 582.80 | | Settlement Costs |
| | Overheads | | | |
| 2 | General Plant Loading | 21.68 | | Line 1 * 0.0372 |
| 3 | SUBTOTAL | 604.48 | | Line 1 + Line 2 |
| 4 | Annualized Cost | | 58.69 | Line 3 * 9.71% constant $ carrying charge |
| | Short Run Costs | | | |
| 5 | Fixed O&M Expenses | | 4.60 | |
| 6 | A&G Loading | | 1.52 | Line 5*0.3314 |
| 7 | SUBTOTAL | | $64.82 | Line 4 + Line 5 + Line 6 |
| | Working Capital Allowance | | | |
| 8 | Materials Supplies On Hand | 6.71 | | Line 3*0.0111 |
| 9 | O&M Allowance | 0.13 | | |
| 10 | Revenue Requirement (Annualized Working Cash) | 6.84 | 0.66 | (Line 8 + Line 9)*9.71% carrying charge |
| 11 | TOTAL ANNUALIZED COST | | $65.48 | Line 7 + Line 10 |
| 12 | Franchise Fees and Uncollectibles | | 0.64 | Line 11*0.00971 |
| 13 | ADJUSTED TOTAL ANNUALIZED COST | | $66.12 | Line 11 + Line 12 |

END OF APPENDIX F

# APPENDIX G
# PACIFIC GAS & ELECTRIC COMPANY
# 1993 GENERAL RATE CASE

## Appendix G - Electric Revenue Allocation

# APPENDIX G

## PACIFIC GAS AND ELECTRIC COMPANY
## 1993 General Rate Case
## ADOPTED REVENUE ALLOCATION
For Rates Effective on January 1, 1993
All Revenues in Thousands of Dollars

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total Sales (MWh) | Present Revenue at 6/1/92 Rates | Present Revenue at EPMC | % Change | Revenue Allocation at EPMC | % Change | Revenue Allocation at SAPC | % Change | Adopted Revenue Allocation | % Change |
| Residential | 24,057,069 | $2,845,547 | $2,887,462 | 1.47% | $2,985,855 | 4.93% | $2,942,550 | 3.41% | $2,969,778 | 4.37% |
| Agricultural | 3,387,729 | $388,017 | $432,615 | 11.49% | $447,275 | 15.27% | $401,197 | 3.40% | $412,729 | 6.37% |
| Streetlighting | 304,659 | $45,028 | $44,683 | -0.77% | $45,539 | 1.14% | $45,896 | 1.93% | $45,539 | 1.14% |
| Small L&P | 6,906,441 | $961,814 | $867,890 | -9.77% | $897,450 | -6.69% | $994,489 | 3.40% | $965,706 | 0.40% |
| Medium L&P | 9,690,383 | $1,024,029 | $1,016,028 | -0.78% | $1,050,805 | 2.61% | $1,059,071 | 3.42% | $1,045,228 | 2.07% |
| E-19 Class | 9,903,439 | $909,971 | $916,837 | 0.75% | $948,403 | 4.22% | $941,309 | 3.44% | $943,362 | 3.67% |
| E-20 Class Tariff | 15,885,760 | $1,205,606 | $1,214,498 | 0.74% | $1,259,101 | 4.44% | $1,249,914 | 3.68% | $1,252,085 | 3.86% |
| E-20 Contracts | 790,225 | $51,920 | $51,920 | 0.00% | $51,920 | 0.00% | $51,920 | 0.00% | $51,920 | 0.00% |
| Total E-20 Class | 16,675,984 | $1,257,526 | $1,266,418 | 0.71% | $1,311,021 | 4.25% | $1,301,834 | 3.52% | $1,304,005 | 3.70% |
| TOTAL SYSTEM | 70,925,705 | $7,431,932 | $7,431,932 | 0.00% | $7,686,347 | 3.42% | $7,686,347 | 3.42% | $7,686,347 | 3.42% |
| TOTAL INCREASE | | | | | $254,415 | | $254,415 | | $254,415 | 5/ |

1/ This table shows net revenues. Net revenues include non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) load management, UCB, and nonfirm service discounts, (f) power factor revenues, (g) CCSF Hetch Hetchy Credits, (h) Residential A/C load control credit and master meter discounts, (i) LIRA surcharge revenues, and (j) unconventional generation credits.

2/ Negotiated contract revenues are excluded from the allocation process and estimated using escalation factors in the contracts.

3/ E-20 Class and System sales and revenues exclude the kWh and refunded ECAC revenue associated with energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to Net Revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1. The total increase in allocated revenues excluding special contracts is 3.32% rather than 3.42%.

5/ Streetlight revenues at present rates reflect facility charges at the levels adopted in PG&E's 1990 GRC adjusted to the 1993 GRC forecast period.

# APPENDIX G
## PACIFIC GAS AND ELECTRIC COMPANY
## 1993 General Rate Case
## INTRACLASS NET REVENUE ALLOCATION 1/2/3/4/

All Revenues in Thousands of Dollars



| A<br>Class/Rate Sch Volt Lvl | B<br>Sales | C<br>Net 6/1/92 Revenue | D<br>Average 6/1/92 Rates | E<br>Net Present Revenue at EPMC | F<br>% Change | G<br>Net Revenue at EPMC | H<br>Average Rates at EPMC | I<br>% Change | J<br>Net Revenue | K<br>Average Rates | L<br>% Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RESIDENTIAL: | | | | | | | | | | | |
| E-1 S | 21,126,636 | $2,550,991 | $0.12075 | $2,728,132 | 0.99% | $2,821,237 | $.12475 | 4.44% | $2,663,268 | $.12606 | 4.40% |
| EL-1 S | 1,489,360 | $150,379 | $0.10097 | | | | | | $156,233 | $.10490 | 3.89% |
| E-7 S | 1,408,319 | $140,724 | $0.09992 | $155,721 | 10.66% | $160,884 | $.11424 | 14.33% | $146,672 | $.10415 | 4.23% |
| E-8 S | 30,717 | $3,199 | $0.10415 | $3,363 | 5.11% | $3,478 | $.11322 | 8.71% | $3,339 | $.10870 | 4.37% |
| Standby | 2,037 | $254 | $0.12486 | $247 | -2.80% | $256 | $.12551 | 0.52% | $265 | $.13030 | 4.36% |
| TOTAL | 24,057,069 | $2,845,547 | $0.11828 | $2,887,462 | 1.47% | $2,985,855 | $.12412 | 4.93% | $2,969,778 | $.12345 | 4.37% |
| AGRICULTURAL | | | | | | | | | | | |
| AG-1 A S | 242,188 | $51,245 | $0.21159 | $55,386 | 8.08% | $57,251 | $.23639 | 11.72% | $54,509 | $.22507 | 6.37% |
| AG-RA S | 24,531 | $3,423 | $0.13953 | $3,863 | 12.85% | $3,988 | $.16258 | 16.52% | $3,631 | $.14802 | 6.08% |
| AG-VA S | 40,768 | $5,596 | $0.13727 | $6,299 | 12.56% | $6,505 | $.15955 | 16.23% | $5,938 | $.14566 | 6.11% |
| AG-4A S | 113,619 | $15,825 | $0.13929 | $17,958 | 13.48% | $18,541 | $.16319 | 17.16% | $16,789 | $.14776 | 6.09% |
| AG-5A S | 80,884 | $8,997 | $0.11123 | $10,515 | 16.87% | $10,865 | $.13433 | 20.77% | $9,559 | $.11818 | 6.26% |
| AG-1 B S | 436,195 | $69,733 | $0.15757 | $63,343 | -7.84% | $65,495 | $.15015 | -4.71% | $73,123 | $.16764 | 6.39% |
| AG-RB S | 30,609 | $4,085 | $0.13346 | $3,864 | -5.42% | $3,994 | $.13049 | -2.23% | $4,344 | $.14190 | 6.33% |
| AG-VB S | 24,973 | $3,283 | $0.13147 | $3,160 | -3.15% | $3,287 | $.13162 | 0.12% | $3,491 | $.13979 | 6.33% |
| AG-4B | 386,782 | $48,276 | $0.12481 | $48,472 | 0.41% | $50,109 | $.12955 | 3.80% | $51,337 | $.13273 | 6.34% |
| AG-4C S | 18,850 | $2,426 | $0.12870 | $2,385 | -1.69% | $2,465 | $.13078 | 1.61% | $2,579 | $.13683 | 6.32% |
| AG-5B | 1,921,489 | $170,872 | $0.08893 | $210,200 | 23.02% | $217,376 | $.11313 | 27.22% | $181,833 | $.09463 | 6.41% |
| AG-5C S | 66,529 | $5,225 | $0.07854 | $7,118 | 36.23% | $7,362 | $.11066 | 40.90% | $5,562 | $.08360 | 6.45% |
| Standby | 312 | $31 | $0.10046 | $34 | 7.36% | $35 | $.11154 | 11.03% | $33 | $.10691 | 6.41% |
| TOTAL | 3,387,729 | $388,017 | $0.11454 | $432,615 | 11.49% | $447,275 | $.13203 | 15.27% | $412,729 | $.12183 | 6.37% |

# APPENDIX G
## PACIFIC GAS AND ELECTRIC COMPANY
### 1993 General Rate Case
### INTRACLASS NET REVENUE ALLOCATION 1/2/3/4/
All Revenues in Thousands of Dollars



| A<br>Class/Rate Sch Volt Lvl | B<br>Sales | C<br>Net 6/1/92 Revenue | D<br>Average 6/1/92 Rates | E<br>Net Present Revenue at EPMC | F<br>% Change | G<br>Net Revenue at EPMC | H<br>Average Rates at EPMC | I<br>% Change | J<br>Net Revenue | K<br>Average Rates | L<br>% Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| STREETLIGHTS /6 | | | | | | | | | | | |
| LS-1 S | 101,357 | $26,946 | $0.26585 | | | | | | $27,115 | $.26752 | 0.63% |
| LS-2 S | 187,522 | $15,037 | $0.08019 | | | | | | $15,349 | $.08185 | 2.08% |
| LS-3 S | 2,430 | $182 | $0.07483 | | | | | | $186 | $.07649 | 2.23% |
| OL-1 S | 13,349 | $2,863 | $0.21448 | | | | | | $2,887 | $.21628 | 0.84% |
| TOTAL | $304,659 | $45,028 | $0.14780 | $44,683 | -0.77% | $45,539 | $.14948 | 1.14% | $45,539 | $.14948 | 1.14% |
| SMALL L&P | | | | | | | | | | | |
| A-1 S | 6,349,638 | $903,781 | $0.14234 | $811,344 | -10.23% | $839,007 | $.13213 | -7.17% | $907,448 | $.14291 | 0.41% |
| A-6 S | 427,917 | $42,984 | $0.10045 | $39,330 | -8.50% | $40,664 | $.09503 | -5.40% | $43,173 | $.10089 | 0.44% |
| A-15 S | 1,770 | $470 | $0.26552 | $564 | 20.07% | $581 | $.32797 | 23.52% | $471 | $.26634 | 0.31% |
| TC-1 S | 120,166 | $13,545 | $0.11272 | $15,594 | 15.13% | $16,111 | $.13407 | 18.94% | $13,588 | $.11308 | 0.32% |
| Standby | 6,950 | $1,034 | $0.14876 | $1,058 | 2.37% | $1,088 | $.15653 | 5.22% | $1,026 | $.14767 | -0.73% |
| TOTAL | 6,906,441 | $961,814 | $0.13926 | $867,890 | -9.77% | $897,450 | $.12994 | -6.69% | $965,706 | $.13983 | 0.40% |
| MEDIUM L&P | | | | | | | | | | | |
| A-10 | 9,684,189 | $1,023,287 | $0.10567 | $1,015,297 | -0.78% | $1,050,052 | $.10843 | 2.62% | $1,044,473 | $.10785 | 2.07% |
| Standby | 6,193 | $742 | $0.11981 | $731 | -1.53% | $753 | $.12157 | 1.47% | $754 | $.12180 | 1.66% |
| TOTAL | 9,690,383 | $1,024,029 | $0.10567 | $1,016,028 | -0.78% | $1,050,805 | $.10844 | 2.61% | $1,045,228 | $.10786 | 2.07% |
| E-19 CLASS | | | | | | | | | | | |
| E-19 T | 8,593 | $727 | $0.08456 | $960 | 32.08% | $993 | $.11551 | 36.60% | $753 | $.08768 | 3.69% |
| E-19/25 P | 562,797 | $47,339 | $0.08411 | $43,071 | -9.02% | $44,583 | $.07922 | -5.82% | $49,100 | $.08724 | 3.72% |
| E-19/25 S | 9,288,525 | $857,054 | $0.09227 | 866,855 | 1.14% | $896,690 | $.09654 | 4.62% | $888,496 | $.09566 | 3.67% |
| A-RTP-19 S | 25,993 | $2,399 | $0.09230 | $2,278 | -5.07% | $2,355 | $.09062 | -1.82% | $2,486 | $.09565 | 3.63% |
| Standby | 17,531 | $2,452 | $0.13986 | $3,673 | 49.81% | $3,782 | $.21574 | 54.25% | $2,526 | $.14408 | 3.02% |
| TOTAL | 9,903,439 | $909,971 | $0.09188 | $916,837 | 0.75% | $948,403 | $.09576 | 4.22% | $943,362 | $.09526 | 3.67% |

APPENDIX G

## PACIFIC GAS AND ELECTRIC COMPANY

1993 General Rate Case

## INTRACLASS NET REVENUE ALLOCATION 1/2/3/4/

All Revenues in Thousands of Dollars



| A<br>Class/Rate Sch Volt Lvl | B<br>Sales | C<br>Net 6/1/92 Revenue | D<br>Average 6/1/92 Rates | E<br>Net Present Revenue at EPMC | F<br>% Change | G<br>Net Revenue at EPMC | H<br>Average Rates at EPMC | I<br>% Change | J<br>Net Revenue | K<br>Average Rates | L<br>% Change |
|---|---|---|---|---|---|---|---|---|---|---|---|
| E-20 CLASS | | | | | | | | | | | |
| E-20 T | 3,681,356 | $210,684 | $0.05723 | $200,163 | -4.99% | $208,117 | $.05653 | -1.22% | $219,383 | $.05959 | 4.13% |
| E-20 P | 7,069,090 | $539,592 | $0.07633 | $518,649 | -3.88% | $537,856 | $.07609 | -0.32% | $560,467 | $.07928 | 3.87% |
| E-20 S | 4,585,173 | $407,915 | $0.08896 | $449,141 | 10.11% | $464,936 | $.10140 | 13.98% | $423,059 | $.09227 | 3.71% |
| A-RTP-20 P | 70,234 | $6,085 | $0.08664 | $5,395 | -11.35% | $5,582 | $.07947 | -8.28% | $6,305 | $.08978 | 3.61% |
| A-RTP-20 S | 174,094 | $14,535 | $0.08349 | $14,941 | 2.79% | $15,454 | $.08877 | 6.32% | $15,059 | $.08650 | 3.61% |
| Standby | 305,813 | $26,795 | $0.08762 | $26,210 | -2.18% | $27,156 | $.08880 | 1.35% | $27,810 | $.09094 | 3.79% |
| E-20 Tariffs | 15,885,760 | $1,205,606 | $0.07589 | $1,214,498 | 0.74% | $1,259,101 | $.07926 | 4.44% | $1,252,085 | $.07882 | 3.86% |
| Contracts: T | 398,288 | $27,255 | $0.06843 | $27,255 | 0.00% | $27,255 | $.06843 | 0.00% | $27,255 | $.06843 | 0.00% |
| Contracts: P | 362,646 | $22,895 | $0.06313 | $22,895 | 0.00% | $22,895 | $.06313 | 0.00% | $22,895 | $.06313 | 0.00% |
| Contracts: S | 29,291 | $1,770 | $0.06044 | $1,770 | 0.00% | $1,770 | $.06044 | 0.00% | $1,770 | $.06044 | 0.00% |
| Total Contracts | 790,225 | $51,920 | $0.06570 | $51,920 | 0.00% | $51,920 | $.06570 | | $51,920 | $.06570 | 0.00% |
| TOTAL E-20 | 16,675,984 | $1,257,526 | $0.07541 | $1,266,418 | 0.71% | $1,311,021 | $.07862 | 4.25% | $1,304,005 | $.07820 | 3.70% |
| SYSTEM TOTAL | 70,925,705 | $7,431,932 | $0.10478 | $7,431,932 | 0.00% | $7,686,347 | $.10785 | 3.42% | $7,686,347 | $.10837 | 3.42% |
| Check | 70,925,705 | $7,431,932 | | $7,431,932 | | $7,686,347 | | | $7,686,347 | | 5/ |
| TOTAL INCREASE | | | | | | $254,415 | | | $254,415 | | |

1/ This table shows net revenues. Net revenues include allocated revenues and non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) UCB, load mgmt, and nonfirm discounts, (f) power factor revenues, (g) CCSF Credits, (h) Residential A/C load control and master meter discounts, (h) LIRA surcharge revenue, and (i) unconventional generation credits.

2/ Negotiated contract revenues are excluded from the allocation process and escalated using escalation factors in the contracts.

3/ E-20 Class and System sales exclude energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to Net Revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1. The total increase in allocated revenues excluding special contracts is "&ROUND($EF$176*100,2)&"% rather than "&ROUND($EL$177*100,2)&"%."

5/ Streetlight revenues at present rates reflect facility charges at the levels adopted in PG&E's 1990 GRC for the ECAC forecast period.

# APPENDIX G
## PACIFIC GAS AND ELECTRIC COMPANY
## 1993 General Rate Case
## Calculation of Low-Income Ratepayer Assistance Surcharge

| LIRA Program Costs | | A | B | C | D | E |
|---|---|---|---|---|---|---|
| Line No. | Description: | Pre-surcharge Non-LIRA Rate | LIRA Rate | Effective Discount (Col A-Col B) | Billing Determinants | Low-Income Discount (Col C*Col D) |
| 1 | EL-1 Tier 1 | 0.11928 | 0.10139 | 0.01789 | 1,118,158,664 | $20,003,858 |
| 2 | EL-1 Tier 2 | 0.13779 | 0.11712 | 0.02067 | 370,653,462 | $7,661,407 |
| 3 | EL-1 Minimum Bill | 5.00 | 4.25 | 0.75 | 27,910 | $20,933 |
| 4 | EL-7 Meter Charge | 4.40 | 0.00 | 4.4 | 20,632 | $90,781 |
| 5 | EL-8 Customer Charge | 13.92 | 11.83 | 2.09 | 258 | $539 |
| 6 | EL-8 Summer | 0.12260 | 0.10421 | 0.01839 | 156,221 | $2,873 |
| 7 | EL-8 Winter | 0.07034 | 0.05979 | 0.01055 | 152,146 | $1,605 |
| 8 | Total (Sum of Lines 1 through 7) | | | | | $27,781,996 |
| 9 | Forecast LIRA Account Balance on 12/31/92 | | | | | ($544,000) |
| 10 | Total LIRA Program Costs (Line 8 + Line 9) | | | | | $27,237,996 |

**Sales Subject to LIRA Surcharge**

| | | |
|---|---|---|
| 11 | Total Forecast Sales (kWh) (Adjusted for EE discount & includes CCSF power from Hetch Hetchy sales) | 71,267,079,748 |
| | Adjustments: | |
| 12 | EE Adjustment (already included in line 11) | 0 |
| 13 | Low-income forecast period sales (Col D Lines 1,2,6, and 7)) | 1,489,120,493 |
| 14 | Low-income forecast period minimum bill sales | 547,618 |
| 15 | Street Light Sales (LS-1, LS-2, LS-3, TC-1) | 406,623,875 |
| 16 | Special Contract Sales | 790,224,515 |
| 17 | Total Adjustments (Sum of Lines 12 through 16) | 2,686,516,501 |
| 18 | Total kWh Sales Subject to LIRA Surcharge (Line 11 - Line 17) | 68,580,563,247 |

**Calculation of the LIRA Surcharge**

| | | |
|---|---|---|
| 19 | Total LIRA Program Costs ($) (Line 10) | $27,237,996 |
| 20 | Total kWh Sales Subject to LIRA Surcharge (Line 18) | 68,580,563,247 |
| 21 | LIRA surcharge ($/kWh) [(Line 17/Line 18)] | 0.00040 |

Notes:

1. The LIRA administrative costs will be recovered in base rates rather than the LIRA surcharge beginning in January 1993. Line 9, however, does include LIRA administrative costs incurred through the end of 1992.
2. The Residential rates shown are interim numbers, and do not reflect revisions PG&E might propose in the rate design phase of this proceeding.

END OF APPENDIX G



CACD/jsl/2

## APPENDIX H - ELECTRIC RATES
## PACIFIC GAS AND ELECTRIC COMPANY

### TABLE OF CONTENTS

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

RESIDENTIAL RATES, 1 of 2

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-1 | | | | | | |
| 2 | | | | | | | |
| 3 | MINIMUM BILL ($/MONTH) | $5.00 | $5.00 | $5.00 | $5.00 | 0.0% | 0.0% |
| 4 | ES UNIT DISCOUNT ($/UNIT/MONTH) | $3.22 | $3.22 | $3.22 | $3.22 | 0.0% | 0.0% |
| 5 | ET UNIT DISCOUNT ($/UNIT/MONTH) | $11.01 | $11.01 | $11.01 | $11.01 | 0.0% | 0.0% |
| 6 | ES/ET MINIMUM RATE LIMITER ($/KWH) | $0.05091 | $0.05091 | $0.04893 | $0.04893 | -3.9% | -3.9% |
| 7 | | | | | | | |
| 8 | TIER 1 ENERGY ($/KWH) | $0.11439 | $0.11439 | $0.11968 | $0.11968 | 4.6% | 4.6% |
| 9 | TIER 2 ENERGY ($/KWH) | $0.13290 | $0.13290 | $0.13819 | $0.13819 | 4.0% | 4.0% |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | SCHEDULE EL-1 (LIRA) | | | | | | |
| 13 | | | | | | | |
| 14 | MINIMUM BILL ($/MONTH) | $4.25 | $4.25 | $4.25 | $4.25 | 0.0% | 0.0% |
| 15 | | | | | | | |
| 16 | TIER 1 ENERGY ($/KWH) | $0.09701 | $0.09701 | $0.10139 | $0.10139 | 4.5% | 4.5% |
| 17 | TIER 2 ENERGY ($/KWH) | $0.11274 | $0.11274 | $0.11712 | $0.11712 | 3.9% | 3.9% |
| 18 | | | | | | | |
| 19 | | | | | | | |
| 20 | SCHEDULES E-7 AND EL-7 | | | | | | |
| 21 | | | | | | | |
| 22 | MINIMUM BILL ($/MONTH) | $5.00 | $5.00 | $5.00 | $5.00 | 0.0% | 0.0% |
| 23 | E-7 METER CHARGE ($/MONTH) | $4.40 | $4.40 | $4.40 | $4.40 | 0.0% | 0.0% |
| 24 | EL-7 METER CHARGE($/MONTH) | $0.00 | $0.00 | $0.00 | $0.00 | 0.0% | 0.0% |
| 25 | | | | | | | |
| 26 | ON-PEAK ENERGY ($/KWH) | $0.31399 | $0.10113 | $0.32724 | $0.10516 | 4.2% | 4.0% |
| 27 | OFF-PEAK ENERGY ($/KWH) | $0.09219 | $0.07728 | $0.09585 | $0.08028 | 4.0% | 3.9% |
| 28 | BASELINE DISCOUNT ($/KWH) | $0.01851 | $0.01851 | $0.01850 | $0.01850 | -0.1% | -0.1% |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | SCHEDULE E-8 | | | | | | |
| 32 | | | | | | | |
| 33 | CUSTOMER CHARGE ($/MONTH) | $13.92 | $13.92 | $13.92 | $13.92 | 0.0% | 0.0% |
| 34 | ENERGY CHARGE ($/KWH) | $0.11742 | $0.06722 | $0.12300 | $0.07074 | 4.8% | 5.2% |
| 35 | | | | | | | |
| 36 | | | | | | | |
| 37 | SCHEDULE EL-8 (LIRA) | | | | | | |
| 38 | | | | | | | |
| 39 | CUSTOMER CHARGE ($/MONTH) | $11.83 | $11.83 | $11.83 | $11.83 | 0.0% | 0.0% |
| 40 | ENERGY CHARGE ($/KWH) | $0.09958 | $0.05691 | $0.10421 | $0.05979 | 4.7% | 5.1% |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

RESIDENTIAL RATES, 2 of 2

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULES E-A7 AND EL-A7 | | | | | | |
| 2 | | | | | | | |
| 3 | MINIMUM BILL ($/MONTH) | $5.00 | $5.00 | $5.00 | $5.00 | 0.0% | 0.0% |
| 4 | E-A7 METER CHARGE ($/MONTH) | $4.40 | $4.40 | $4.40 | $4.40 | 0.0% | 0.0% |
| 5 | EL-A7 METER CHARGE($/MONTH) | $0.00 | $0.00 | $0.00 | $0.00 | 0.0% | 0.0% |
| 6 | | | | | | | |
| 7 | ON-PEAK ENERGY ($/KWH) | $0.37839 | $0.10041 | $0.37808 | $0.10427 | -0.1% | 3.8% |
| 8 | OFF-PEAK ENERGY ($/KWH) | $0.08190 | $0.07743 | $0.08783 | $0.08041 | 7.2% | 3.8% |
| 9 | BASELINE DISCOUNT ($/KWH) | $0.01851 | $0.01851 | $0.01850 | $0.01850 | -0.1% | -0.1% |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | SCHEDULE E-B7 | | | | | | |
| 13 | | | | | | | |
| 14 | MINIMUM BILL ($/MONTH) | $5.00 | $5.00 | $5.00 | $5.00 | 0.0% | 0.0% |
| 15 | E-B7 METER CHARGE ($/MONTH) | $4.40 | $4.40 | $4.40 | $4.40 | 0.0% | 0.0% |
| 16 | | | | | | | |
| 17 | CRITICAL ($/KWH) | $0.55856 | $0.55856 | $0.55777 | $0.55777 | -0.1% | -0.1% |
| 18 | HIGH ($/KWH) | $0.32186 | | $0.32107 | | -0.2% | |
| 19 | MEDIUM ($/KWH) | | $0.09294 | | $0.09640 | | 3.7% |
| 20 | LOW ($/KWH) | $0.07278 | $0.07278 | $0.07682 | $0.07682 | 5.6% | 5.6% |
| 21 | | | | | | | |
| 22 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

SMALL L&P RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE A-1 | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE: SINGLE-PHASE ($/MO.) | $7.50 | $7.50 | $7.50 | $7.50 | 0.0% | 0.0% |
| 4 | CUSTOMER CHARGE: POLYPHASE ($/MO.) | $8.75 | $8.75 | $8.75 | $8.75 | 0.0% | 0.0% |
| 5 | | | | | | | |
| 6 | ENERGY ($/KWH) | $0.14940 | $0.12279 | $0.15003 | $0.12331 | 0.4% | 0.4% |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | SCHEDULE A-6 | | | | | | |
| 10 | | | | | | | |
| 11 | CUSTOMER CHARGE ($/MONTH) | $7.50 | $7.50 | $7.50 | $7.50 | 0.0% | 0.0% |
| 12 | METER CHARGE ($/MONTH) | $6.20 | $6.20 | $6.20 | $6.20 | 0.0% | 0.0% |
| 13 | POLYPHASE CHARGE ($/MO.) | $8.75 | $8.75 | $8.75 | $8.75 | 0.0% | 0.0% |
| 14 | | | | | | | |
| 15 | ON-PEAK ENERGY ($/KWH) | $0.28698 | | $0.28829 | | 0.5% | |
| 16 | PART-PEAK ENERGY ($/KWH) | $0.14349 | $0.07654 | $0.14415 | $0.07689 | 0.5% | 0.5% |
| 17 | OFF-PEAK ENERGY ($/KWH) | $0.07462 | $0.05741 | $0.07496 | $0.05767 | 0.5% | 0.5% |
| 18 | | | | | | | |
| 19 | | | | | | | |
| 20 | SCHEDULE A-15 | | | | | | |
| 21 | | | | | | | |
| 22 | CUSTOMER CHARGE ($/MONTH) | $7.50 | $7.50 | $7.50 | $7.50 | 0.0% | 0.0% |
| 23 | FACILITY CHARGE ($/MONTH) | $7.80 | $7.80 | $7.80 | $7.80 | 0.0% | 0.0% |
| 24 | | | | | | | |
| 25 | ENERGY ($/KWH) | $0.18400 | $0.16427 | $0.18487 | $0.16505 | 0.5% | 0.5% |
| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | SCHEDULE TC-1 | | | | | | |
| 29 | | | | | | | |
| 30 | CUSTOMER CHARGE ($/MONTH) | $7.50 | $7.50 | $7.50 | $7.50 | 0.0% | 0.0% |
| 31 | | | | | | | |
| 32 | ENERGY ($/KWH) | $0.10591 | $0.10591 | $0.10627 | $0.10627 | 0.3% | 0.3% |
| 33 | | | | | | | |
| 34 | | | | | | | |
| 35 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

MEDIUM L&P RATES

| LINE NO. | | CURRENT 6/1/92 RATES SUMMER | CURRENT 6/1/92 RATES WINTER | ADOPTED 1/1/93 RATES SUMMER | ADOPTED 1/1/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE A-10 | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $63.00 | $63.00 | $63.00 | $63.00 | 0.0% | 0.0% |
| 4 | MAXIMUM DEMAND - TRANSMISSION ($/KW/MO) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 5 | MAXIMUM DEMAND - PRIMARY ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 6 | MAXIMUM DEMAND - SECONDARY ($/KW/MONTH | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 7 | | | | | | | |
| 8 | ENERGY CHARGE($/KWH) | $0.09918 | $0.07687 | $0.10107 | $0.07834 | 1.9% | 1.9% |
| 9 | | | | | | | |
| 10 | | | | | | | |
| 11 | SCHEDULE E-14 | | | | | | |
| 12 | | | | | | | |
| 13 | CUSTOMER CHARGE ($/MONTH) | $63.00 | $63.00 | $63.00 | $63.00 | 0.0% | 0.0% |
| 14 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 15 | MAXIMUM DEMAND - TRANSMISSION ($/KW/MO) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 16 | MAXIMUM DEMAND - PRIMARY ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 17 | MAXIMUM DEMAND - SECONDARY ($/KW/MONTH | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 18 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $11.10 | | $12.05 | | 8.6% | |
| 19 | | | | | | | |
| 20 | ON-PEAK ENERGY ($/KWH) | $0.13881 | | $0.15427 | | 11.1% | |
| 21 | PART-PEAK ENERGY ($/KWH) | $0.08583 | $0.06451 | $0.07924 | $0.06775 | -7.7% | 5.0% |
| 22 | OFF-PEAK ENERGY ($/KWH) | $0.05761 | $0.05587 | $0.06049 | $0.05869 | 5.0% | 5.1% |
| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | | | | | | | |
| 26 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

E-19 FIRM RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-19 T FIRM | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE > 500 KW ($/MONTH) | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | CUSTOMER CHARGE < 500 KW ($/MONTH) | $63.00 | $63.00 | $63.00 | $63.00 | 0.0% | 0.0% |
| 5 | TOU METER CHARGE < 500 KW | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 7 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $9.00 | | $9.35 | | 3.9% | |
| 8 | ON-PEAK ENERGY ($/KWH) | $0.11409 | | $0.11198 | | -1.8% | |
| 9 | PARTIAL-PEAK ENERGY ($/KWH) | $0.07744 | $0.06621 | $0.07601 | $0.06499 | -1.8% | -1.8% |
| 10 | OFF-PEAK ENERGY ($/KWH) | $0.05912 | $0.05735 | $0.05803 | $0.05629 | -1.8% | -1.8% |
| 11 | ON-PEAK RATE LIMIT ($/KWH) | $0.66285 | | $0.71886 | | 8.5% | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | SCHEDULE E-19 P FIRM | | | | | | |
| 15 | | | | | | | |
| 16 | CUSTOMER CHARGE > 500 KW ($/MONTH) | $250.00 | $250.00 | $250.00 | $250.00 | 0.0% | 0.0% |
| 17 | CUSTOMER CHARGE < 500 KW ($/MONTH) | $63.00 | $63.00 | $63.00 | $63.00 | 0.0% | 0.0% |
| 18 | TOU METER CHARGE < 500 KW | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 19 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 20 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $10.90 | | $11.30 | | 3.7% | |
| 21 | ON-PEAK ENERGY ($/KWH) | $0.10773 | | $0.11112 | | 3.1% | |
| 22 | PARTIAL-PEAK ENERGY ($/KWH) | $0.07313 | $0.06252 | $0.07543 | $0.06449 | 3.1% | 3.1% |
| 23 | OFF-PEAK ENERGY ($/KWH) | $0.05583 | $0.05416 | $0.05759 | $0.05586 | 3.1% | 3.1% |
| 24 | AVERAGE RATE LIMIT ($/KWH) | $0.15379 | | $0.16679 | | 8.5% | |
| 25 | ON-PEAK RATE LIMIT ($/KWH) | $0.90501 | | $0.98148 | | 8.5% | |
| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | SCHEDULE E-19 S FIRM | | | | | | |
| 29 | | | | | | | |
| 30 | CUSTOMER CHARGE > 500 KW ($/MONTH) | $280.00 | $280.00 | $280.00 | $280.00 | 0.0% | 0.0% |
| 31 | CUSTOMER CHARGE < 500 KW ($/MONTH) | $63.00 | $63.00 | $63.00 | $63.00 | 0.0% | 0.0% |
| 32 | TOU METER CHARGE < 500 KW | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 33 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 34 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $11.60 | | $12.05 | | 3.9% | |
| 35 | ON-PEAK ENERGY ($/KWH) | $0.11277 | | $0.11675 | | 3.5% | |
| 36 | PARTIAL-PEAK ENERGY ($/KWH) | $0.07654 | $0.06544 | $0.07924 | $0.06775 | 3.5% | 3.5% |
| 37 | OFF-PEAK ENERGY ($/KWH) | $0.05843 | $0.05669 | $0.06049 | $0.05869 | 3.5% | 3.5% |
| 38 | AVERAGE RATE LIMIT ($/KWH) | $0.15379 | | $0.16679 | | 8.5% | |
| 39 | ON-PEAK RATE LIMIT ($/KWH) | $0.91033 | | $0.98725 | | 8.5% | |
| 40 | | | | | | | |
| 41 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

E-19 NONFIRM RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-19 T NONFIRM | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 5 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 7 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $3.12 | | $3.47 | | 11.2% | |
| 8 | ON-PEAK ENERGY ($/KWH) | $0.08512 | | $0.08301 | | -2.5% | |
| 9 | PARTIAL-PEAK ENERGY ($/KWH) | $0.06728 | $0.06489 | $0.06585 | $0.06367 | -2.1% | -1.9% |
| 10 | OFF-PEAK ENERGY ($/KWH) | $0.05780 | $0.05603 | $0.05671 | $0.05497 | -1.9% | -1.9% |
| 11 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 12 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | SCHEDULE E-19 P NONFIRM | | | | | | |
| 16 | | | | | | | |
| 17 | CUSTOMER CHARGE ($/MONTH) | $250.00 | $250.00 | $250.00 | $250.00 | 0.0% | 0.0% |
| 18 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 19 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 20 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 21 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $5.02 | | $5.42 | | 8.0% | |
| 22 | ON-PEAK ENERGY ($/KWH) | $0.07876 | | $0.08215 | | 4.3% | |
| 23 | PARTIAL-PEAK ENERGY ($/KWH) | $0.06297 | $0.06120 | $0.06527 | $0.06317 | 3.7% | 3.2% |
| 24 | OFF-PEAK ENERGY ($/KWH) | $0.05451 | $0.05284 | $0.05627 | $0.05454 | 3.2% | 3.2% |
| 25 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 26 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 27 | | | | | | | |
| 28 | | | | | | | |
| 29 | SCHEDULE E-19 S NONFIRM | | | | | | |
| 30 | | | | | | | |
| 31 | CUSTOMER CHARGE ($/MONTH) | $280.00 | $280.00 | $280.00 | $280.00 | 0.0% | 0.0% |
| 32 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 33 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 34 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 35 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $5.72 | | $6.17 | | 7.9% | |
| 36 | ON-PEAK ENERGY ($/KWH) | $0.08380 | | $0.08778 | | 4.8% | |
| 37 | PARTIAL-PEAK ENERGY ($/KWH) | $0.06638 | $0.06412 | $0.06908 | $0.06643 | 4.1% | 3.6% |
| 38 | OFF-PEAK ENERGY ($/KWH) | $0.05711 | $0.05537 | $0.05917 | $0.05737 | 3.6% | 3.6% |
| 39 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 40 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 41 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

E-20 FIRM RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-20 T | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH)-FIRM | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 5 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $9.00 | | $9.35 | | 3.9% | |
| 6 | ON-PEAK ENERGY ($/KWH) | $0.08485 | | $0.08801 | | 3.7% | |
| 7 | PARTIAL-PEAK ENERGY ($/KWH) | $0.05759 | $0.04924 | $0.05974 | $0.05107 | 3.7% | 3.7% |
| 8 | OFF-PEAK ENERGY ($/KWH) | $0.04397 | $0.04265 | $0.04561 | $0.04424 | 3.7% | 3.7% |
| 9 | ON-PEAK RATE LIMIT ($/KWH) | $0.65109 | | $0.70630 | | 8.5% | |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | SCHEDULE E-20 P FIRM | | | | | | |
| 13 | | | | | | | |
| 14 | CUSTOMER CHARGE ($/MONTH) | $220.00 | $220.00 | $220.00 | $220.00 | 0.0% | 0.0% |
| 15 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 16 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $10.90 | | $11.30 | | 3.7% | |
| 17 | ON-PEAK ENERGY ($/KWH) | $0.10278 | | $0.10635 | | 3.5% | |
| 18 | PARTIAL-PEAK ENERGY ($/KWH) | $0.06976 | $0.05965 | $0.07218 | $0.06172 | 3.5% | 3.5% |
| 19 | OFF-PEAK ENERGY ($/KWH) | $0.05326 | $0.05166 | $0.05511 | $0.05345 | 3.5% | 3.5% |
| 20 | AVERAGE RATE LIMIT ($/KWH) | $0.13106 | | $0.14217 | | 8.5% | |
| 21 | ON-PEAK RATE LIMIT ($/KWH) | $0.88895 | | $0.96433 | | 8.5% | |
| 22 | | | | | | | |
| 23 | | | | | | | |
| 24 | SCHEDULE E-20 S FIRM | | | | | | |
| 25 | | | | | | | |
| 26 | CUSTOMER CHARGE ($/MONTH) | $330.00 | $330.00 | $330.00 | $330.00 | 0.0% | 0.0% |
| 27 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 28 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $11.60 | | $12.05 | | 3.9% | |
| 29 | ON-PEAK ENERGY ($/KWH) | $0.11116 | | $0.11519 | | 3.6% | |
| 30 | PARTIAL-PEAK ENERGY ($/KWH) | $0.07545 | $0.06451 | $0.07819 | $0.06685 | 3.6% | 3.6% |
| 31 | OFF-PEAK ENERGY ($/KWH) | $0.05760 | $0.05588 | $0.05969 | $0.05791 | 3.6% | 3.6% |
| 32 | AVERAGE RATE LIMIT ($/KWH) | $0.13106 | | $0.14217 | | 8.5% | |
| 33 | ON-PEAK RATE LIMIT ($/KWH) | $0.89418 | | $0.97001 | | 8.5% | |
| 34 | | | | | | | |
| 35 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

## E-20 NONFIRM RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-20 T NONFIRM | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 5 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 7 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $3.12 | | $3.47 | | 11.2% | |
| 8 | ON-PEAK ENERGY ($/KWH) | $0.05588 | | $0.05904 | | 5.7% | |
| 9 | PARTIAL-PEAK ENERGY ($/KWH) | $0.04743 | $0.04792 | $0.04958 | $0.04975 | 4.5% | 3.8% |
| 10 | OFF-PEAK ENERGY ($/KWH) | $0.04265 | $0.04133 | $0.04429 | $0.04292 | 3.8% | 3.8% |
| 11 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 12 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | SCHEDULE E-20 P NONFIRM | | | | | | |
| 16 | | | | | | | |
| 17 | CUSTOMER CHARGE ($/MONTH) | $220.00 | $220.00 | $220.00 | $220.00 | 0.0% | 0.0% |
| 18 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 19 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 20 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 21 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $5.02 | | $5.42 | | 8.0% | |
| 22 | ON-PEAK ENERGY ($/KWH) | $0.07381 | | $0.07738 | | 4.8% | |
| 23 | PARTIAL-PEAK ENERGY ($/KWH) | $0.05960 | $0.05833 | $0.06202 | $0.06040 | 4.1% | 3.6% |
| 24 | OFF-PEAK ENERGY ($/KWH) | $0.05194 | $0.05034 | $0.05379 | $0.05213 | 3.6% | 3.6% |
| 25 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 26 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 27 | | | | | | | |
| 28 | | | | | | | |
| 29 | SCHEDULE E-20 S NONFIRM | | | | | | |
| 30 | | | | | | | |
| 31 | CUSTOMER CHARGE ($/MONTH) | $330.00 | $330.00 | $330.00 | $330.00 | 0.0% | 0.0% |
| 32 | CURTAILABLE METER CHARGE($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 33 | INTERRUPTIBLE METER CHARGE ($/MONTH) | $200.00 | $200.00 | $200.00 | $200.00 | 0.0% | 0.0% |
| 34 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 35 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $5.72 | | $6.17 | | 7.9% | |
| 36 | ON-PEAK ENERGY ($/KWH) | $0.08219 | | $0.08622 | | 4.9% | |
| 37 | PARTIAL-PEAK ENERGY ($/KWH) | $0.06529 | $0.06319 | $0.06803 | $0.06553 | 4.2% | 3.7% |
| 38 | OFF-PEAK ENERGY ($/KWH) | $0.05628 | $0.05456 | $0.05837 | $0.05659 | 3.7% | 3.7% |
| 39 | UFR CREDIT ($/KWH) | $0.00091 | $0.00091 | $0.00091 | $0.00091 | 0.0% | 0.0% |
| 40 | NONCOMPLIANCE PENALTY ($/KWH/EVENT) | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | $8.40/$4.20 | | |
| 41 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

REAL TIME PRICING RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE A-RTP PRIMARY | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | E-20 CUSTOMER CHARGE ($/MONTH) | $220.00 | $220.00 | $220.00 | $220.00 | 0.0% | 0.0% |
| 5 | OPTIONAL SERVICE CHARGE ($/MONTH) | $275.00 | $275.00 | $275.00 | $275.00 | 0.0% | 0.0% |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.55 | $3.55 | 9.2% | 9.2% |
| 7 | | | | | | | |
| 8 | BASE ENERGY RATE ($/KWH) | $0.00334 | $0.00334 | $0.00346 | $0.00346 | 3.7% | 3.7% |
| 9 | | | | | | | |
| 10 | ON-PEAK ENERGY MULTIPLIER | 2.5818 | | 2.6287 | | 1.8% | |
| 11 | PART-PEAK ENERGY MULTIPLIER | 2.5818 | 1.8944 | 2.6287 | 1.9087 | 1.8% | 0.8% |
| 12 | OFF-PEAK ENERGY MULTIPLIER | 1.8944 | 1.8944 | 1.9087 | 1.9087 | 0.8% | 0.8% |
| 13 | | | | | | | |
| 14 | LOAD MANAGEMENT PRICE SIGNAL ($/KWH) | $0.63 | | $0.65 | | 3.2% | |
| 15 | TRANSMISSION & DISTRIBUTION ADDER ($/KWH) | $0.09195 | | $0.09331 | | 1.5% | |
| 16 | | | | | | | |
| 17 | | | | | | | |
| 18 | SCHEDULE A-RTP SECONDARY | | | | | | |
| 19 | | | | | | | |
| 20 | E-19 CUSTOMER CHARGE ($/MONTH) | $280.00 | $280.00 | $280.00 | $280.00 | 0.0% | 0.0% |
| 21 | E-20 CUSTOMER CHARGE ($/MONTH) | $330.00 | $330.00 | $330.00 | $330.00 | 0.0% | 0.0% |
| 22 | OPTIONAL SERVICE CHARGE ($/MONTH) | $275.00 | $275.00 | $275.00 | $275.00 | 0.0% | 0.0% |
| 23 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.50 | $4.50 | 8.4% | 8.4% |
| 24 | | | | | | | |
| 25 | BASE ENERGY RATE ($/KWH) | $0.00334 | $0.00334 | $0.00346 | $0.00346 | 3.7% | 3.7% |
| 26 | | | | | | | |
| 27 | ON-PEAK ENERGY MULTIPLIER | 2.5818 | | 2.6287 | | 1.8% | |
| 28 | PART-PEAK ENERGY MULTIPLIER | 2.5818 | 1.8944 | 2.6287 | 1.9087 | 1.8% | 0.8% |
| 29 | OFF-PEAK ENERGY MULTIPLIER | 1.8944 | 1.8944 | 1.9087 | 1.9087 | 0.8% | 0.8% |
| 30 | | | | | | | |
| 31 | LOAD MANAGEMENT PRICE SIGNAL ($/KWH) | $0.63 | | $0.65 | | 3.2% | |
| 32 | TRANSMISSION & DISTRIBUTION ADDER ($/KWH) | $0.09195 | | $0.09331 | | 1.5% | |
| 33 | | | | | | | |
| 34 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

E-25 LARGE L&P RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-25T | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 5 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $9.00 | | $9.35 | | 3.9% | |
| 6 | ON-PEAK ENERGY ($/KWH) | $0.13242 | | $0.12997 | | -1.8% | |
| 7 | PART-PEAK ENERGY ($/KWH) | $0.07744 | $0.06621 | $0.07601 | $0.06499 | -1.8% | -1.8% |
| 8 | OFF-PEAK ENERGY ($/KWH) | $0.05912 | $0.05735 | $0.05803 | $0.05629 | -1.8% | -1.8% |
| 9 | ON-PEAK RATE LIMIT ($/KWH) | $0.66285 | | $0.71886 | | 8.5% | |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | SCHEDULE E-25P | | | | | | |
| 13 | | | | | | | |
| 14 | CUSTOMER CHARGE ($/MONTH) | $250.00 | $250.00 | $250.00 | $250.00 | 0.0% | 0.0% |
| 15 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 16 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $10.90 | | $11.30 | | 3.7% | |
| 17 | ON-PEAK ENERGY ($/KWH) | $0.12504 | | $0.12896 | | 3.1% | |
| 18 | PART-PEAK ENERGY ($/KWH) | $0.07313 | $0.06252 | $0.07543 | $0.06449 | 3.1% | 3.1% |
| 19 | OFF-PEAK ENERGY ($/KWH) | $0.05583 | $0.05416 | $0.05759 | $0.05586 | 3.1% | 3.1% |
| 20 | AVERAGE RATE LIMIT ($/KWH) | $0.15379 | | $0.16679 | | 8.5% | |
| 21 | ON-PEAK RATE LIMIT ($/KWH) | $0.90501 | | $0.98148 | | 8.5% | |
| 22 | | | | | | | |
| 23 | | | | | | | |
| 24 | SCHEDULE E-25S | | | | | | |
| 25 | | | | | | | |
| 26 | CUSTOMER CHARGE ($/MONTH) | $280.00 | $280.00 | $280.00 | $280.00 | 0.0% | 0.0% |
| 27 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 28 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $11.60 | | $12.05 | | 3.9% | |
| 29 | ON-PEAK ENERGY ($/KWH) | $0.13088 | | $0.13551 | | 3.5% | |
| 30 | PART-PEAK ENERGY ($/KWH) | $0.07654 | $0.06544 | $0.07924 | $0.06775 | 3.5% | 3.5% |
| 31 | OFF-PEAK ENERGY ($/KWH) | $0.05843 | $0.05669 | $0.06049 | $0.05869 | 3.5% | 3.5% |
| 32 | AVERAGE RATE LIMIT ($/KWH) | $0.15379 | | $0.16679 | | 8.5% | |
| 33 | ON-PEAK RATE LIMIT ($/KWH) | $0.91033 | | $0.98725 | | 8.5% | |
| 34 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

E-26 LARGE L&P RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE E-26T | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $510.00 | $510.00 | $510.00 | $510.00 | 0.0% | 0.0% |
| 4 | CURTAILABLE METER CHARGE ($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 5 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 6 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $4.74 | | $5.09 | | 7.4% | |
| 7 | ON-PEAK ENERGY ($/KWH) | $0.09041 | | $0.08796 | | -2.7% | |
| 8 | PART-PEAK ENERGY ($/KWH) | $0.07253 | $0.06525 | $0.07110 | $0.06403 | -2.0% | -1.9% |
| 9 | OFF-PEAK ENERGY ($/KWH) | $0.05816 | $0.05639 | $0.05707 | $0.05533 | -1.9% | -1.9% |
| 10 | EXCESS DEMAND CHARGE / KWH | $6.10 | $6.10 | $6.10 | $6.10 | 0.0% | 0.0% |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | SCHEDULE E-26P | | | | | | |
| 14 | | | | | | | |
| 15 | CUSTOMER CHARGE ($/MONTH) | $220.00 | $220.00 | $220.00 | $220.00 | 0.0% | 0.0% |
| 16 | CURTAILABLE METER CHARGE ($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 17 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 18 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $6.64 | | $7.04 | | 6.0% | |
| 19 | ON-PEAK ENERGY ($/KWH) | $0.08303 | | $0.08695 | | 4.7% | |
| 20 | PART-PEAK ENERGY ($/KWH) | $0.06822 | $0.06156 | $0.07052 | $0.06353 | 3.4% | 3.2% |
| 21 | OFF-PEAK ENERGY ($/KWH) | $0.05487 | $0.05320 | $0.05663 | $0.05490 | 3.2% | 3.2% |
| 22 | EXCESS DEMAND CHARGE / KWH | $6.10 | $6.10 | $6.10 | $6.10 | 0.0% | 0.0% |
| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | | | | | | | |
| 26 | SCHEDULE E-26S | | | | | | |
| 27 | | | | | | | |
| 28 | CUSTOMER CHARGE ($/MONTH) | $330.00 | $330.00 | $330.00 | $330.00 | 0.0% | 0.0% |
| 29 | CURTAILABLE METER CHARGE ($/MONTH) | $190.00 | $190.00 | $190.00 | $190.00 | 0.0% | 0.0% |
| 30 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 31 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $7.34 | | $7.79 | | 6.1% | |
| 32 | ON-PEAK ENERGY ($/KWH) | $0.08887 | | $0.09350 | | 5.2% | |
| 33 | PART-PEAK ENERGY ($/KWH) | $0.07163 | $0.06448 | $0.07433 | $0.06679 | 3.8% | 3.6% |
| 34 | OFF-PEAK ENERGY ($/KWH) | $0.05747 | $0.05573 | $0.05953 | $0.05773 | 3.6% | 3.6% |
| 35 | EXCESS DEMAND CHARGE / KWH | $6.10 | $6.10 | $6.10 | $6.10 | 0.0% | 0.0% |
| 36 | | | | | | | |
| 37 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

STANDBY RATES

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE S - TRANSMISSION | | | | | | |
| 2 | | | | | | | |
| 3 | CONTRACT CAPACITY CHARGE ($/KW/MO.) | $0.60 | $0.60 | $0.60 | $0.60 | 0.0% | 0.0% |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | SCHEDULE S - PRIMARY | | | | | | |
| 8 | | | | | | | |
| 9 | CONTRACT CAPACITY CHARGE ($/KW/MO.) | $3.25 | $3.25 | $3.40 | $3.40 | 4.6% | 4.6% |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | SCHEDULE S - SECONDARY | | | | | | |
| 14 | | | | | | | |
| 15 | CONTRACT CAPACITY CHARGE ($/KW/MO.) | $4.15 | $4.15 | $4.30 | $4.30 | 3.6% | 3.6% |
| 16 | | | | | | | |
| 17 | | | | | | | |
| 18 | | | | | | | |
| 19 | REDUCED CUSTOMER CHARGES ($/MO) | | | | | | |
| 20 | | | | | | | |
| 21 | A-1 / A-6 | $3.20 | $3.20 | $3.20 | $3.20 | 0.0% | 0.0% |
| 22 | A-10 / E19 V | $27.00 | $27.00 | $27.00 | $27.00 | 0.0% | 0.0% |
| 23 | E-19 TRANSMISSION / E-20 TRANSMISSION | $426.00 | $426.00 | $426.00 | $426.00 | 0.0% | 0.0% |
| 24 | | | | | | | |
| 25 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

AGRICULTURAL RATES, 1 of 5

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE AG-1A | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 4 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $2.15 | $2.15 | $2.30 | $2.30 | 7.0% | 7.0% |
| 5 | | | | | | | |
| 6 | ENERGY CHARGE ($/KWH) | $0.14035 | $0.14035 | $0.15041 | $0.15041 | 7.2% | 7.2% |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | SCHEDULE AG-RA | | | | | | |
| 10 | | | | | | | |
| 11 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 12 | METER CHARGE ($/MONTH) | $6.20 | $6.20 | $6.20 | $6.20 | 0.0% | 0.0% |
| 13 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $2.15 | $2.15 | $2.30 | $2.30 | 7.0% | 7.0% |
| 14 | | | | | | | |
| 15 | ON-PEAK ENERGY ($/KWH) | $0.33665 | | $0.36022 | | 7.0% | |
| 16 | PART-PEAK ENERGY ($/KWH) | | $0.07053 | | $0.07547 | | 7.0% |
| 17 | OFF-PEAK ENERGY ($/KWH) | $0.07851 | $0.05609 | $0.08401 | $0.06002 | 7.0% | 7.0% |
| 18 | | | | | | | |
| 19 | | | | | | | |
| 20 | SCHEDULE AG-VA | | | | | | |
| 21 | | | | | | | |
| 22 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 23 | METER CHARGE ($/MONTH) | $6.20 | $6.20 | $6.20 | $6.20 | 0.0% | 0.0% |
| 24 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $2.15 | $2.15 | $2.30 | $2.30 | 7.0% | 7.0% |
| 25 | | | | | | | |
| 26 | ON-PEAK ENERGY ($/KWH) | $0.33063 | | $0.35348 | | 6.9% | |
| 27 | PART-PEAK ENERGY ($/KWH) | | $0.06927 | | $0.07406 | | 6.9% |
| 28 | OFF-PEAK ENERGY ($/KWH) | $0.07539 | $0.05509 | $0.08060 | $0.05890 | 6.9% | 6.9% |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | SCHEDULE AG-4A | | | | | | |
| 32 | | | | | | | |
| 33 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 34 | METER CHARGE ($/MONTH) | $6.20 | $6.20 | $6.20 | $6.20 | 0.0% | 0.0% |
| 35 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $2.15 | $2.15 | $2.30 | $2.30 | 7.0% | 7.0% |
| 36 | | | | | | | |
| 37 | ON-PEAK ENERGY ($/KWH) | $0.32821 | | $0.35114 | | 7.0% | |
| 38 | PART-PEAK ENERGY ($/KWH) | | $0.06876 | | $0.07356 | | 7.0% |
| 39 | OFF-PEAK ENERGY ($/KWH) | $0.06601 | $0.05468 | $0.07062 | $0.05850 | 7.0% | 7.0% |
| 40 | | | | | | | |
| 41 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

AGRICULTURAL RATES, 2 of 5

| | | CURRENT | | ADOPTED | | | |
|---|---|---|---|---|---|---|---|
| LINE NO. | | 06/01/92 RATES SUMMER | 06/01/92 RATES WINTER | 01/01/93 RATES SUMMER | 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
| 1 | SCHEDULE AG-5A | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 4 | METER CHARGE ($/MONTH) | $6.20 | $6.20 | $6.20 | $6.20 | 0.0% | 0.0% |
| 5 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $5.15 | $5.15 | $5.50 | $5.50 | 6.8% | 6.8% |
| 6 | ON-PEAK ENERGY ($/KWH) | $0.23441 | | $0.25002 | | 6.7% | |
| 7 | PART-PEAK ENERGY ($/KWH) | | $0.04911 | | $0.05238 | | 6.7% |
| 8 | OFF-PEAK ENERGY ($/KWH) | $0.04823 | $0.03906 | $0.05144 | $0.04166 | 6.7% | 6.7% |
| 9 | | | | | | | |
| 10 | | | | | | | |
| 11 | SCHEDULE AG-6A | | | | | | |
| 12 | | | | | | | |
| 13 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 14 | CONNECTED LOAD CHARGE ($/KW/MONTH) | $5.15 | $5.15 | $5.50 | $5.50 | 6.8% | 6.8% |
| 15 | ENERGY CHARGE ($/KWH) | $0.08215 | $0.04276 | $0.08745 | $0.04588 | 6.4% | 7.3% |
| 16 | | | | | | | |
| 17 | | | | | | | |
| 18 | SCHEDULE AG-1B | | | | | | |
| 19 | | | | | | | |
| 20 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 21 | MAXIMUM DEMAND CHARGE | | | | | | |
| 22 | SECONDARY VOLTAGE ($/KW/MONTH) | $2.60 | $1.80 | $2.75 | $1.90 | 5.8% | 5.6% |
| 23 | PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH) | $0.40 | $0.30 | $0.45 | $0.30 | 0 | 0 |
| 24 | ENERGY CHARGE ($/KWH) | $0.12155 | $0.12155 | $0.12975 | $0.12975 | 6.7% | 6.7% |
| 25 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | SCHEDULE AG-RB | | | | | | |
| 29 | | | | | | | |
| 30 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 31 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 32 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.60 | | $2.75 | | 5.8% | |
| 33 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 34 | SECONDARY VOLTAGE ($/KW/MONTH) | $2.60 | $1.80 | $2.75 | $1.90 | 5.8% | 5.6% |
| 35 | PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH) | $0.40 | $0.30 | $0.45 | $0.30 | 12.5% | 0.0% |
| 36 | ON-PEAK ENERGY ($/KWH) | $0.29134 | | $0.31386 | | 7.73% | |
| 37 | PART-PEAK ENERGY ($/KWH) | | $0.07914 | | $0.08460 | | 6.9% |
| 38 | OFF-PEAK ENERGY ($/KWH) | $0.08544 | $0.06294 | $0.09133 | $0.06728 | 6.9% | 6.9% |
| 39 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 40 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

AGRICULTURAL RATES, 3 of 5

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE AG-VB | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 4 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 5 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.60 | | $2.75 | | 5.8% | |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 7 | SECONDARY VOLTAGE ($/KW/MONTH) | $2.60 | $1.80 | $2.75 | $1.90 | 5.8% | 5.6% |
| 8 | PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH) | $0.40 | $0.30 | $0.45 | $0.30 | 12.5% | 0.0% |
| 9 | ON-PEAK ENERGY ($/KWH) | $0.25887 | | $0.27876 | | 7.7% | |
| 10 | PART-PEAK ENERGY ($/KWH) | | $0.07676 | | $0.08205 | | 6.9% |
| 11 | OFF-PEAK ENERGY ($/KWH) | $0.06032 | $0.06103 | $0.08585 | $0.06523 | 6.9% | 6.9% |
| 12 | | | | | | | |
| 13 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 14 | | | | | | | |
| 15 | | | | | | | |
| 16 | SCHEDULE AG-4B | | | | | | |
| 17 | | | | | | | |
| 18 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 19 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 20 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.60 | | $2.75 | | 5.8% | |
| 21 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 22 | SECONDARY VOLTAGE ($/KW/MONTH) | $2.60 | $1.80 | $2.75 | $1.90 | 5.8% | 5.6% |
| 23 | PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH) | $0.40 | $0.30 | $0.45 | $0.30 | 12.5% | 0.0% |
| 24 | ON-PEAK ENERGY ($/KWH) | $0.21464 | | $0.22946 | | 6.9% | |
| 25 | PART-PEAK ENERGY ($/KWH) | | $0.07089 | | $0.07583 | | 7.0% |
| 26 | OFF-PEAK ENERGY ($/KWH) | $0.06735 | $0.05636 | $0.07204 | $0.06029 | 7.0% | 7.0% |
| 27 | | | | | | | |
| 28 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 29 | | | | | | | |
| 30 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

AGRICULTURAL RATES, 4 of 5

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE AG-4C | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 4 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 5 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.60 | | $2.75 | | 5.8% | |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 7 | SECONDARY VOLTAGE ($/KW/MONTH) | $2.60 | $1.80 | $2.75 | $1.90 | 5.8% | 5.6% |
| 8 | PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH) | $0.40 | $0.30 | $0.45 | $0.30 | 12.5% | 0.0% |
| 9 | ON-PEAK ENERGY ($/KWH) | $0.21464 | | $0.22946 | | 6.9% | |
| 10 | PART-PEAK ENERGY ($/KWH) | $0.09658 | $0.07089 | $0.10449 | $0.07583 | 8.2% | 7.0% |
| 11 | OFF-PEAK ENERGY ($/KWH) | $0.06257 | $0.05636 | $0.06769 | $0.06029 | 8.2% | 7.0% |
| 12 | | | | | | | |
| 13 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 14 | | | | | | | |
| 15 | | | | | | | |
| 16 | SCHEDULE AG-5B | | | | | | |
| 17 | | | | | | | |
| 18 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 19 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 20 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.55 | | $2.70 | | 5.9% | |
| 21 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 22 | SECONDARY VOLTAGE | $6.15 | $4.15 | $6.55 | $4.40 | 6.5% | 6.0% |
| 23 | PRIMARY VOLTAGE DISCOUNT | $0.90 | $0.60 | $1.00 | $0.65 | 11.1% | 8.3% |
| 24 | ON-PEAK ENERGY ($/KWH) | $0.13997 | | $0.14964 | | 6.9% | |
| 25 | PART-PEAK ENERGY ($/KWH) | | $0.04149 | | $0.04419 | | 6.5% |
| 26 | OFF-PEAK ENERGY ($/KWH) | $0.04003 | $0.03299 | $0.04264 | $0.03514 | 6.5% | 6.5% |
| 27 | | | | | | | |
| 28 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 29 | | | | | | | |



CACD/czw/2

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

AGRICULTURAL RATES, 5 of 5

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE AG-5C | | | | | | |
| 2 | | | | | | | |
| 3 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 4 | METER CHARGE ($/MONTH) | $5.10 | $5.10 | $5.10 | $5.10 | 0.0% | 0.0% |
| 5 | ON-PEAK DEMAND CHARGE ($/KW/MONTH) | $2.55 | | $2.70 | | 5.9% | |
| 6 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 7 | SECONDARY VOLTAGE | $6.15 | $4.15 | $6.55 | $4.40 | 6.5% | 6.0% |
| 8 | PRIMARY VOLTAGE DISCOUNT | $0.90 | $0.60 | $1.00 | $0.65 | 11.1% | 8.3% |
| 9 | | | | | | | |
| 10 | ON-PEAK ENERGY ($/KWH) | $0.13997 | | $0.14964 | | 6.9% | |
| 11 | PART-PEAK ENERGY ($/KWH) | $0.05508 | $0.04149 | $0.05900 | $0.04419 | 7.1% | 6.5% |
| 12 | OFF-PEAK ENERGY ($/KWH) | $0.03503 | $0.03299 | $0.03752 | $0.03514 | 7.1% | 6.5% |
| 13 | | | | | | | |
| 14 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 15 | | | | | | | |
| 16 | | | | | | | |
| 17 | SCHEDULE AG-6B | | | | | | |
| 18 | | | | | | | |
| 19 | CUSTOMER CHARGE ($/MONTH) | $10.00 | $10.00 | $10.00 | $10.00 | 0.0% | 0.0% |
| 20 | MAXIMUM DEMAND CHARGE ($/KW/MONTH) | | | | | | |
| 21 | SECONDARY VOLTAGE | $6.15 | $4.15 | $6.55 | $4.40 | 6.5% | 6.0% |
| 22 | PRIMARY VOLTAGE DISCOUNT | $0.90 | $0.60 | $1.00 | $0.65 | 11.1% | 8.3% |
| 23 | | | | | | | |
| 24 | ENERGY CHARGE ($/KWH) | $0.06836 | $0.03626 | $0.07566 | $0.04066 | 10.7% | 12.1% |
| 25 | | | | | | | |
| 26 | RATE LIMITER ($/KWH) | $1.15549 | $1.15549 | $1.22848 | $1.22848 | 6.3% | 6.3% |
| 27 | | | | | | | |
| 28 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
*Electric Department*
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

STREETLIGHTING RATES, 1 of 2

| LINE NO. | | CURRENT 06/01/92 RATES SUMMER | CURRENT 06/01/92 RATES WINTER | ADOPTED 01/01/93 RATES SUMMER | ADOPTED 01/01/93 RATES WINTER | % CHANGE SUMMER | % CHANGE WINTER |
|---|---|---|---|---|---|---|---|
| 1 | SCHEDULE LS-1 | | | | | | |
| 2 | | | | | | | |
| 3 | ENERGY CHARGE ($/KWH) | $0.07290 | $0.07290 | $0.07457 | $0.07457 | 2.3% | 2.3% |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | SCHEDULE LS-2 | | | | | | |
| 8 | | | | | | | |
| 9 | ENERGY CHARGE ($/KWH) | $0.07290 | $0.07290 | $0.07457 | $0.07457 | 2.3% | 2.3% |
| 10 | | | | | | | |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | SCHEDULE LS-3 | | | | | | |
| 14 | | | | | | | |
| 15 | SERVICE CHARGE ($/METER/MO.) | $3.00 | $3.00 | $3.00 | $3.00 | 0.0% | 0.0% |
| 16 | | | | | | | |
| 17 | SWITCHING CHARGE ($/CIRCUIT) | $3.25 | $3.25 | $3.25 | $3.25 | 0.0% | 0.0% |
| 18 | | | | | | | |
| 19 | ENERGY CHARGE ($/KWH) | $0.07290 | $0.07290 | $0.07457 | $0.07457 | 2.3% | 2.3% |
| 20 | | | | | | | |
| 21 | | | | | | | |
| 22 | | | | | | | |
| 23 | SCHEDULE OL-1 | | | | | | |
| 24 | | | | | | | |
| 25 | ENERGY CHARGE ($/KWH) | $0.07317 | $0.07317 | $0.07497 | $0.07497 | 2.5% | 2.5% |
| 26 | | | | | | | |
| 27 | | | | | | | |

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993
STREETLIGHTING RATES, 2 of 2

| NOMINAL LAMP RATINGS | | | ALL NIGHT RATES PER LAMP PER MONTH | | | | | | | | | | | | | HALF-HOUR AD | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | AVERAGE | | SCHEDULE LS-2 | | | SCHEDULE LS-1 | | | | | | | | | | LS-1 & | |
| LAMP WATTS | KWHR PER MONTH | INITIAL LUMENS | A | B | C | A | B | C | D | D1 | E | E1 | F | F1 | OL-1 | LS-2 | OL-1 |
| MERCURY VAPOR LAMPS | | | | | | | | | | | | | | | | | |
| 100 | 40 | 3,500 | 3.134 | 4.029 | 4.534 | 9.634 | - | 7.949 | - | - | - | - | - | - | - | 0.136 | - |
| 175 | 68 | 7,500 | 5.222 | 6.061 | 6.565 | 11.164 | 8.106 | 10.206 | - | - | 13.655 | 13.655 | 20.239 | 19.174 | 11.191 | 0.230 | 0.232 |
| 250 | 97 | 11,000 | 7.364 | 8.306 | 8.812 | 14.403 | 10.622 | - | - | - | - | - | - | - | - | 0.329 | - |
| 400 | 152 | 21,000 | 11.486 | 12.381 | 12.885 | 18.670 | 14.726 | - | - | - | - | - | - | - | 18.730 | 0.515 | 0.518 |
| 700 | 266 | 37,000 | 19.987 | 21.249 | 21.753 | 27.748 | 23.817 | - | - | - | - | - | - | - | - | 0.902 | - |
| 1,000 | 377 | 57,000 | 28.264 | 29.441 | 29.946 | - | - | - | - | - | - | - | - | - | - | 1.278 | - |
| INCANDESCENT LAMPS | | | | | | | | | | | | | | | | | |
| 58 | 20 | 600 | - | - | - | 10.063 | - | - | - | - | - | - | - | - | - | 0.068 | - |
| 92 | 31 | 1,000 | 2.463 | 5.060 | 5.564 | 10.903 | - | - | - | - | - | - | - | - | - | 0.105 | - |
| 189 | 65 | 2,500 | 4.998 | 7.780 | 8.284 | 13.639 | 9.946 | - | - | - | - | - | - | - | - | 0.220 | - |
| 295 | 101 | 4,000 | 7.683 | 10.533 | 11.037 | 16.399 | 12.706 | - | - | - | - | - | - | - | - | 0.342 | - |
| 405 | 139 | 6,000 | 10.516 | 13.737 | 14.242 | 19.636 | - | - | - | - | - | - | - | - | - | 0.471 | - |
| 620 | 212 | 10,000 | 15.960 | 19.141 | 19.645 | - | - | - | - | - | - | - | - | - | - | 0.719 | - |
| 860 | 294 | 15,000 | 22.075 | 25.609 | - | - | - | - | - | - | - | - | - | - | - | 0.997 | - |
| LOW PRESSURE SODIUM VAPOR LAMPS | | | | | | | | | | | | | | | | | |
| 35 | 21 | 4,800 | 1.717 | - | - | - | - | - | - | - | - | - | - | - | - | 0.071 | - |
| 55 | 29 | 8,000 | 2.314 | - | - | - | - | - | - | - | - | - | - | - | - | 0.098 | - |
| 90 | 45 | 13,500 | 3.507 | - | - | - | - | - | - | - | - | - | - | - | - | 0.153 | - |
| 135 | 62 | 21,500 | 4.774 | - | - | - | - | - | - | - | - | - | - | - | - | 0.210 | - |
| 180 | 78 | 33,000 | 5.967 | - | - | - | - | - | - | - | - | - | - | - | - | 0.264 | - |
| HIGH PRESSURE SODIUM VAPOR LAMPS | | | | | | | | | | | | | | | | | |
| AT 120 VOLTS | | | | | | | | | | | | | | | | | |
| 70 | 29 | 5,800 | 2.314 | 3.360 | 3.864 | 8.011 | - | 6.946 | 10.119 | 10.119 | 10.160 | 10.160 | 15.707 | 15.178 | 8.022 | 0.098 | 0.099 |
| 100 | 41 | 9,500 | 3.208 | 4.273 | 4.777 | 8.918 | - | 7.914 | 11.099 | 11.099 | 11.101 | 11.101 | 16.714 | 16.217 | 8.930 | 0.139 | 0.140 |
| 150 | 60 | 16,000 | 4.625 | 5.690 | 6.194 | 10.786 | - | 9.399 | 12.434 | 12.434 | 12.653 | 12.653 | 18.079 | 18.039 | - | 0.203 | - |
| AT 240 VOLTS | | | | | | | | | | | | | | | | | |
| 70 | 34 | 5,800 | 2.666 | 3.723 | 4.227 | - | - | - | - | - | - | - | - | - | - | 0.115 | - |
| 100 | 47 | 9,500 | 3.666 | 4.720 | 5.224 | - | - | - | - | - | - | - | - | - | - | 0.159 | - |
| 150 | 69 | 16,000 | 5.296 | 6.361 | 6.865 | - | - | - | - | - | - | - | - | - | - | 0.234 | - |
| 200 | 81 | 22,000 | 6.191 | 7.256 | 7.760 | 13.790 | - | 11.621 | - | - | 14.785 | 14.785 | 21.573 | 20.762 | 13.823 | 0.276 | 0.276 |
| 250 | 100 | 25,500 | 7.608 | 8.672 | 9.177 | 14.962 | - | 13.267 | - | - | 16.000 | 16.000 | 23.356 | 22.667 | | 0.339 | - |
| 310 | 119 | 37,000 | 9.026 | - | - | - | - | - | - | - | - | - | - | - | - | 0.403 | - |
| 400 | 154 | 46,000 | 11.635 | 12.699 | 13.203 | 20.023 | - | 17.062 | - | - | 20.625 | 20.625 | 27.880 | 27.072 | - | 0.522 | - |
| METAL HALIDE LAMPS | | | | | | | | | | | | | | | | | |
| 400 | 162 | 30,000 | 12.231 | - | - | - | - | - | - | - | - | - | - | - | - | 0.549 | - |
| 1,000 | 387 | 90,000 | 29.010 | - | - | - | - | - | - | - | - | - | - | - | - | 1.312 | - |

Energy Rate @ 0.07457 per kwh LS-1 & LS-2
0.07497 per kwh OL-1



CACD/czw/2

APPENDIX H
PACIFIC GAS AND ELECTRIC COMPANY
Electric Department
Forecast Period: Jan. 1, 1993 Through Dec. 31, 1993

CUSTOMER AND SALES FORECASTS

| Class/Rate Sch. | Customers | MWh Sale |
|---|---|---|
| RESIDENTIAL: | | |
| E-1 | 3,656,682 | 22,615,996 |
| E-7 | 97,751 | 1,408,319 |
| E-8 | 2,143 | 30,717 |
| Standby | 4 | 2,037 |
| TOTAL | 3,756,580 | 24,057,069 |
| AGRICULTURAL | | |
| AG-1A | 44,822 | 242,188 |
| AG-RA | 2,293 | 24,531 |
| AG-VA | 3,371 | 40,768 |
| AG-4A | 10,428 | 113,619 |
| AG-5A | 3,079 | 80,884 |
| AG-1B | 11,485 | 436,195 |
| AG-RB | 744 | 30,609 |
| AG-VB | 621 | 24,973 |
| AG-4B | 7,777 | 386,782 |
| AG-4C | 541 | 18,850 |
| AG-5B | 10,339 | 1,921,489 |
| AG-5C | 117 | 66,529 |
| Standby | 1 | 312 |
| TOTAL | 95,618 | 3,387,729 |
| STREETLIGHTS | | |
| LS-1 | N/A | 101,357 |
| LS-2 | N/A | 187,522 |
| LS-3 | N/A | 2,430 |
| OL-1 | N/A | 13,349 |
| TOTAL | 26,296 | 304,658 |

| Class/Rate Sch. | Customers | MWh Sales |
|---|---|---|
| SMALL L&P | | |
| A-1 | 379,932 | 6,349,638 |
| A-6 | 8,473 | 427,917 |
| A-15 | 881 | 1,770 |
| TC-1 | 9,091 | 120,166 |
| Standby | 105 | 6,950 |
| TOTAL | 398,482 | 6,906,441 |
| MEDIUM L&P | | |
| A-10 | 40,336 | 9,684,189 |
| Standby | 25 | 6,193 |
| TOTAL | 40,361 | 9,690,382 |
| E-19 CLASS | | |
| E-19 T | 7 | 8,593 |
| E-19/25 P | 242 | 562,797 |
| E-19/25 S | 10,693 | 9,288,525 |
| A-RTP-19 S | 8 | 25,993 |
| Standby | 41 | 17,531 |
| TOTAL | 10,991 | 9,903,439 |
| E-20 CLASS | | |
| E-20 T | 64 | 3,681,356 |
| E-20 P | 409 | 7,069,090 |
| E-20 S | 609 | 4,585,173 |
| A-RTP-20 P | 5 | 70,234 |
| A-RTP-20 S | 27 | 174,094 |
| Standby | 83 | 305,813 |
| E-20 Tariffs | 1,197 | 15,885,760 |
| Contracts: T | 2 | 398,288 |
| Contracts: P | 4 | 362,646 |
| Contracts: S | 3 | 29,291 |
| Total Contracts | 9 | 790,225 |
| TOTAL E-20 | 1,206 | 16,675,985 |
| SYSTEM TOTAL | | 70,925,703 |

(End of Appendix H)

Appendix I
Pacific Gas & Electric Company
Gas Department

## TABLE OF CONTENTS

## APPENDIX I

## PACIFIC GAS & ELECTRIC COMPANY
## GAS DEPARTMENT
## CORE BUNDLED RATES AND REVENUES

| Line No. | (A) | PRESENT RATES & REVENUES EFFECTIVE 11/1/92 Adj Bill Det. MTH or CUST (B) | Rate $/TH (C) | Revenue $000 (D) | ADOPTED RATES & REVENUES EFFECTIVE 1/1/93 Adj Bill Det. MTH or CUST (E) | Rate $/TH (F) | Revenue $000 (G) | CHANGE IN RATES $/TH (H) | % (I) |
|---|---|---|---|---|---|---|---|---|---|
| | RES. NON-LIRA | | | | | | | | |
| 1 | Tier I (Baseline) | 2,929,709 | .49589 | 1,452,815 | 2,929,709 | .51187 | 1,499,636 | .01598 | 3.22 % |
| 2 | Tier II | 953,008 | .66920 | 637,754 | 953,008 | .69146 | 658,972 | .02226 | 3.33 % |
| 3 | Subtotal Non-LIRA | 3,882,717 | .53843 | 2,090,569 | 3,882,717 | .55595 | 2,158,608 | .01752 | 3.25 % |
| | RES. LIRA | | | | | | | | |
| 4 | Tier I (Baseline) | 255,265 | .41985 | 107,174 | 255,265 | .43342 | 110,638 | .01357 | 3.23 % |
| 5 | Tier II | 83,045 | .56684 | 47,074 | 83,045 | .58539 | 48,614 | .01855 | 3.27 % |
| 6 | Subtotal LIRA | 338,310 | .45594 | 154,248 | 338,310 | .47073 | 159,252 | .01479 | 3.24 % |
| 7 | Pre-GS/GT Discnt Subtot. | 4,221,027 | .53182 | 2,244,816 | 4,221,027 | .54912 | 2,317,859 | .01730 | 3.25 % |
| 8 | GS,GT Discount | | | -16,474 | | | -16,474 | | |
| 9 | Total Residential | 4,221,027 | .52791 | 2,228,343 | 4,221,027 | .54522 | 2,301,385 | .01730 | 3.28 % |
| | SCHEDULE G-NR1 (1) | | | | | | | | |
| 10 | Customer Charge | 196,284 | 14.60 | 68,777 | 196,284 | 13.42 | 63,221 | -1.18 | -8.08 % |
| 11 | Summer Vol. Rate | 734,540 | .42962 | 315,574 | 734,540 | .44812 | 329,162 | .01850 | 4.31 % |
| 12 | Winter Vol. Rate | 845,230 | .57999 | 490,224 | 845,230 | .60496 | 511,333 | .02497 | 4.31 % |
| 13 | Total G-NR1 | 1,579,770 | .55361 | 874,575 | 1,579,770 | .57206 | 903,716 | .01845 | 3.33 % |
| | SCHEDULE G-NR2 (1) | | | | | | | | |
| 14 | Customer Charge | 514.8 | 163.94 | 2,026 | 514.8 | 150.70 | 1,862 | -13.24 | -8.08 % |
| 15 | Summer Vol. Rate | 171,960 | .37461 | 64,418 | 171,960 | .38635 | 66,437 | .01175 | 3.14 % |
| 16 | Winter Vol. Rate | 186,120 | .50572 | 94,125 | 186,120 | .52158 | 97,076 | .01586 | 3.14 % |
| 17 | Total G-NR2 | 358,080 | .44841 | 160,568 | 358,080 | .46184 | 165,375 | .01343 | 2.99 % |
| 18 | Total Commercial | 1,937,850 | .53417 | 1,035,143 | 1,937,850 | .55169 | 1,069,091 | .01752 | 3.28 % |
| 19 | Total Bundled Core | 6,158,877 | .52988 | 3,263,486 | 6,158,877 | .54726 | 3,370,477 | .01737 | 3.28 % |

## NGV BUNDLED RATES AND REVENUES

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | SCHEDULE G-NGV1 (1) | | | | | | | | |
| 20 | Customer Charge | 10 | 14.60 | 3 | 10 | 13.42 | 3 | -1.18 | -8.08 % |
| 21 | Volumetric Rate | 1,580 | .42704 | 675 | 1,580 | .44354 | 701 | .01650 | 3.86 % |
| 22 | Total G-NGV1 | 1,580 | .42915 | 678 | 1,580 | .44548 | 704 | .01633 | 3.81 % |
| | SCHEDULE G-NGV2 (1) | | | | | | | | |
| 23 | Customer Charge | 175 | 14.60 | 61 | 175 | 13.42 | 56 | -1.18 | -8.08 % |
| 24 | Volumetric Rate | 1,570 | .53105 | 834 | 1,570 | .55084 | 865 | .01979 | 3.73 % |
| 25 | Total G-NGV2 | 1,570 | .57010 | 895 | 1,570 | .58674 | 921 | .01663 | 2.92 % |
| 26 | TOTAL G-NGV | 3,150 | .49940 | 1,573 | 3,150 | .51588 | 1,625 | .01648 | 3.30 % |

(1) Changes to the Customer Charges and Volumetric Rates Reflect an Increase in Rev. Requirements and a Correction made to the Rev. Allocation Model.



CACD/WJS/2

APPENDIX I

PACIFIC GAS & ELECTRIC COMPANY
GAS DEPARTMENT
CORE TRANSPORT RATES AND REVENUES

| Line No. | (A) | PRESENT RATES & REVENUES EFFECTIVE 11/1/92 Adj Bill Det. MTH or CUST (B) | Rate $/TH (C) | Revenue $000 (D) | ADOPTED RATES & REVENUES EFFECTIVE 1/1/93 Adj Bill Det. MTH or CUST (E) | Rate $/TH (F) | Revenue $000 (G) | CHANGE IN RATES $/TH (H) | % (I) |
|---|---|---|---|---|---|---|---|---|---|
| | RES. NON-LIRA | | | | | | | | |
| 1 | Tier I (Baseline) | 5,882 | .32812 | 1,930 | 5,882 | .34410 | 2,024 | .01598 | 4.87 % |
| 2 | Tier II | 1,500 | .50143 | 752 | 1,500 | .52369 | 785 | .02226 | 4.44 % |
| 3 | Subtotal Non-LIRA | 7,382 | .36333 | 2,682 | 7,382 | .38058 | 2,809 | .01726 | 4.75 % |
| | RES. LIRA | | | | | | | | |
| 4 | Tier I (Baseline) | 513 | .25208 | 129 | 513 | .26565 | 136 | .01357 | 5.38 % |
| 5 | Tier II | 131 | .39907 | 52 | 131 | .41762 | 55 | .01855 | 4.65 % |
| 6 | Subtotal LIRA | 643 | .28195 | 181 | 643 | .29653 | 191 | .01458 | 5.17 % |
| 7 | Total Residential | 8,025 | .35683 | 2,863 | 8,025 | .37385 | 3,000 | .01704 | 4.78 % |
| | SCHEDULE G-NR1 (1) | | | | | | | | |
| 8 | Customer Charge | 4,171 | 14.60 | 1,462 | 4,171 | 13.42 | 1,343 | -1.18 | -8.08 % |
| 9 | Summer Vol. Rate | 17,550 | .26185 | 4,595 | 17,550 | .28035 | 4,920 | .01850 | 7.06 % |
| 10 | Winter Vol. Rate | 16,020 | .41222 | 6,604 | 16,020 | .43719 | 7,004 | .02497 | 6.06 % |
| 11 | Total G-NR1 | 33,570 | .37714 | 12,661 | 33,570 | .39521 | 13,267 | .01807 | 4.79 % |
| | SCHEDULE G-NR3 (1) | | | | | | | | |
| 12 | Customer Charge | 6 | 163.94 | 23 | 5.8 | 150.70 | 21 | -13.24 | -8.08 % |
| 13 | Summer Rate | 1,870 | .20684 | 387 | 1,870 | .21858 | 409 | .01175 | 5.68 % |
| 14 | Winter Rate | 2,140 | .33795 | 723 | 2,140 | .35381 | 757 | .01586 | 4.69 % |
| 15 | Total G-NR3 | 4,010 | .28246 | 1,133 | 4,010 | .29595 | 1,187 | .01348 | 4.77 % |
| 16 | Commercial Transport | 37,580 | .36704 | 13,793 | 37,580 | .38462 | 14,454 | .01758 | 4.79 % |
| 17 | Total Core Transport | 45,605 | .36524 | 16,657 | 45,605 | .38273 | 17,454 | .01749 | 4.79 % |
| 18 | TOTAL CORE | 6,204,492 | | 3,280,142 | 6,204,492 | | 3,387,931 | | |

CACD/WJS/2

## APPENDIX I

## PACIFIC GAS & ELECTRIC COMPANY
## (GAS DEPARTMENT)
## INDUSTRIAL, UEG, & COGENERATION TRANSPORT RATES AND REVENUES

| Line No. | (A) | PRESENT RATES & REVENUES EFFECTIVE 11/1/92 Adj Bill Det. MTH or CUST (B) | Rate $/TH (C) | Revenue $000 (D) | ADOPTED RATES & REVENUES EFFECTIVE 1/1/93 Adj Bill Det. MTH or CUST (E) | Rate $/TH (F) | Revenue $000 (G) | CHANGE IN RATES $/TH (H) | % (I) |
|---|---|---|---|---|---|---|---|---|---|
| | INDUSTRIAL (1) | | | | | | | | |
| | SCHEDULE G-FT | | | | | | | | |
| 1 | Customer Charge | 552.41 | 602.75 | 7,991 | 552.41 | 554.06 | 7,346 | -48.70 | -8.08 % |
| 2 | Summer Volumetric | 1,161,850 | .11241 | 130,606 | 1,161,850 | .11680 | 135,708 | .00439 | 3.91 % |
| 3 | Winter Volumetric | 865,270 | .12887 | 111,509 | 865,270 | .13327 | 115,313 | .00440 | 3.41 % |
| 4 | Avg. Std. Rate (adj. vol) | 2,027,120 | .12338 | 250,106 | 2,027,120 | .12745 | 258,367 | .00407 | 3.30 % |
| 5 | Avg. Rate (unadj. vol) | 2,027,120 | .12338 | 250,106 | 2,027,120 | .12745 | 258,367 | .00407 | 3.30 % |
| | SCHEDULE G-IT (1) | | | | | | | | |
| 6 | Customer Charge | 356.55 | 602.75 | 5,158 | 356.55 | 554.06 | 4,741 | -48.70 | -8.08 % |
| 7 | Summer Volumetric | 852,088 | .07518 | 64,064 | 851,648 | .07957 | 67,766 | .00439 | 5.83 % |
| 8 | Winter Volumetric | 460,023 | .09164 | 42,159 | 459,707 | .09603 | 44,147 | .00439 | 4.79 % |
| 9 | Avg. Std. Rate (adj. vol) | 1,312,111 | .08489 | 111,380 | 1,311,355 | .08896 | 116,654 | .00407 | 4.80 % |
| 10 | Avg. Rate (unadj. vol) | 1,337,350 | .08328 | 111,380 | 1,337,350 | .08723 | 116,654 | .00394 | 4.74 % |
| | INDUSTRIAL AVERAGES (1) | | | | | | | | |
| 11 | Customer Charge | 908.96 | 602.75 | 13,149 | 908.96 | 554.06 | 12,087 | -48.70 | -8.08 % |
| 12 | Summer Volumetric | 2,013,938 | .09666 | 194,670 | 2,013,498 | .10105 | 203,474 | .00439 | 4.55 % |
| 13 | Winter Volumetric | 1,325,293 | .11595 | 153,668 | 1,324,977 | .12035 | 159,460 | .00440 | 3.79 % |
| 14 | Avg. Std. Rate (adj. vol) | 3,339,231 | .10825 | 361,487 | 3,338,475 | .11233 | 375,021 | .00408 | 3.77 % |
| 15 | Avg. Rate (unadj. vol) | 3,364,470 | .10744 | 361,487 | 3,364,470 | .11147 | 375,021 | .00402 | 3.74 % |
| | UEG (1) | | | | | | | | |
| 16 | Customer Charge | 1 | 93,856 | 2,253 | 1 | 86,273 | 2,071 | -7,582 | -8.08 % |
| 17 | Demand Charge | | | 271,389 | | | 279,654 | 8,265 | 3.05 % |
| 18 | Tier I Volumetric | 744,087 | .04298 | 31,980 | 744,087 | .04518 | 33,621 | .00220 | 5.13 % |
| 19 | Tier II Volumetric | 3,278,003 | .00841 | 27,557 | 3,278,003 | .00877 | 28,749 | .00036 | 4.32 % |
| 20 | Avg. Rate | 4,022,090 | .08284 | 333,180 | 4,022,090 | .08555 | 344,095 | .00271 | 3.28 % |
| | COGEN | | | | | | | | |
| | G-COG Firm | | | | | | | | |
| 21 | Summer Volumetric | 349,987 | .08992 | 31,473 | 349,987 | .09264 | 32,423 | .00272 | 3.02 % |
| 22 | Winter Volumetric | 238,151 | .10597 | 25,238 | 238,151 | .10869 | 25,885 | .00272 | 2.56 % |
| 23 | Avg. Rate | 588,138 | .09642 | 56,710 | 588,138 | .09914 | 58,308 | .00272 | 2.82 % |
| | G-COG Interruptible | | | | | | | | |
| 24 | Summer Volumetric | 175,322 | .05270 | 9,239 | 175,322 | .05541 | 9,714 | .00271 | 5.14 % |
| 25 | Winter Volumetric | 139,787 | .06875 | 9,610 | 139,787 | .07146 | 9,989 | .00271 | 3.94 % |
| 26 | Avg. Rate | 315,108 | .05982 | 18,849 | 315,108 | .06253 | 19,703 | .00271 | 4.53 % |
| | G-COG Averages | | | | | | | | |
| 27 | Summer Volumetric | 525,309 | .07750 | 40,712 | 525,309 | .08021 | 42,137 | .00271 | 3.50 % |
| 28 | Winter Volumetric | 377,938 | .09221 | 34,849 | 377,938 | .09492 | 35,873 | .00271 | 2.94 % |
| 29 | Avg. Rate | 903,247 | .08365 | 75,559 | 903,247 | .08637 | 78,011 | .00271 | 3.24 % |
| 30 | G-P03 Firm | 250,638 | .09643 | 24,169 | 250,638 | .09915 | 24,850 | .00272 | 2.82 % |
| 31 | G-P03 Interruptible | 92,732 | .05992 | 5,557 | 92,732 | .06263 | 5,808 | .00271 | 4.52 % |
| 32 | G-P03 Averages | 343,369 | .08657 | 29,726 | 343,369 | .08929 | 30,658 | .00271 | 3.14 % |
| 33 | Total COGEN | 1,245,616 | .08446 | 105,285 | 1,246,616 | .08717 | 108,668 | .00271 | 3.21 % |
| 34 | GC2 Revenue | 68,004 | | 5,664 | 68,004 | | 5,756 | | |
| 35 | COGEN Including GC2 | 1,314,620 | .08440 | 110,949 | 1,314,620 | .08704 | 114,424 | .00264 | 3.13 % |

CACD/W35/2

# APPENDIX I
# PACIFIC GAS & ELECTRIC COMPANY
# GAS DEPARTMENT
## SUMMARY OF WHOLESALE & NONCORE TRANSPORT RATES & REVENUES

| Line No. | (A) | PRESENT RATES & REVENUES EFFECTIVE 11/1/92 Adj Bill Det. MTH or CUST (B) | Rate $/TH (C) | Revenue $000 (D) | ADOPTED RATES & REVENUES EFFECTIVE 1/1/93 Adj Bill Det. MTH or CUST (E) | Rate $/TH (F) | Revenue $000 (G) | CHANGE IN RATES $/TH (H) | % (I) |
|---|---|---|---|---|---|---|---|---|---|
| | WHOLESALE | | | | | | | | |
| 1 | Demand Charge | | | 26,364 | | | 27,181 | 817 | 3.10 % |
| 2 | Volumetric Rate | 292,940 | .00529 | 1,550 | 292,940 | .00546 | 1,600 | .00017 | 3.22 % |
| 3 | Avg. Rate | 292,940 | .09529 | 27,914 | 292,940 | .09825 | 28,780 | .00296 | 3.10 % |
| | TOTAL NC TRANSPORT | | | | | | | | |
| 4 | Adjusted volumes | 8,968,881 | .09294 | 833,529 | 8,968,125 | .09615 | 862,320 | .00321 | 3.46 % |
| 5 | Unadjusted volumes | 8,994,120 | .09267 | 833,529 | 8,994,120 | .09588 | 862,320 | .00321 | 3.46 % |
| | CORE SUBSCRIPTION | | | | | | | | |
| 6 | Industrial & COGEN | 722,780 | .19140 | 138,337 | 722,780 | .19140 | 138,337 | .00000 | 0.00 % |
| 7 | UEG | 2,614,370 | .19140 | 500,379 | 2,614,370 | .19140 | 500,379 | .00000 | 0.00 % |
| 8 | Wholesale | 138,470 | .19104 | 26,454 | 138,470 | .19104 | 26,454 | .00000 | 0.00 % |
| 9 | Total NC Procurement | 3,475,620 | .19138 | 665,170 | 3,475,620 | .19138 | 665,170 | .00000 | 0.00 % |

## REVENUE SUMMARY

| Line No. | | Present Revenue | Adopted Revenue | $ | % |
|---|---|---|---|---|---|
| | REVENUE SUMMARY | | | | |
| | Core | | | | |
| 10 | Transport | 16,657 | 17,454 | 798 | 4.79 % |
| 11 | Bundled | 3,264,014 | 3,371,005 | 106,991 | 3.28 % |
| 12 | Total Core | 3,280,671 | 3,388,459 | 107,789 | 3.29 % |
| | Noncore | | | | |
| 13 | Transport | 833,529 | 862,320 | 28,791 | 3.45 % |
| 14 | EOR CPUC Revenue | 570 | 570 | | |
| 15 | Procurement | 665,170 | 665,170 | 0 | 0.00 % |
| 16 | Gas cost adjustment | 0 | 0 | | |
| 17 | Total Noncore | 1,499,270 | 1,528,061 | 28,791 | 1.92 % |
| 18 | Total | 4,779,946 | 4,916,520 | 136,574 | 2.86 % |

CACD/W35/2

# APPENDIX I
## PACIFIC GAS & ELECTRIC COMPANY
## GAS DEPARTMENT
## SUMMARY OF WHOLESALE RATES

| | PALO ALTO | | COALINGA | | CP NATIONAL | | SOUTHWEST GAS | | |
|---|---|---|---|---|---|---|---|---|---|
| | Present Rates Rev. | Adopted Rates Rev. | Present Rates Rev. | Adopted Rates Rev. | Present Rates Rev. | Adopted Rates Rev. | Present Rates | Adopted Rates Rev. | |
| Aug-92 | $148,209 | $152,854 | $5,541 | $5,735 | $2,828 | $2,929 | $526,351 | $541,960 | 1 |
| Sep-92 | $163,774 | $168,916 | $7,388 | $7,646 | $2,828 | $2,929 | $536,174 | $552,101 | 2 |
| Oct-92 | $211,215 | $217,900 | $6,464 | $6,691 | $3,771 | $3,906 | $555,861 | $572,638 | 3 |
| Nov-92 | $329,909 | $340,592 | $12,005 | $12,425 | $3,771 | $3,906 | $730,147 | $753,831 | 4 |
| Dec-92 | $426,654 | $440,486 | $25,857 | $26,763 | $8,485 | $8,788 | $1,095,895 | $1,131,427 | 5 |
| Jan-93 | $466,989 | $432,148 | $37,862 | $39,188 | $15,054 | $15,622 | $1,295,417 | $1,337,397 | 6 |
| Feb-93 | $349,553 | $360,886 | $23,086 | $23,895 | $16,027 | $16,599 | $1,195,589 | $1,234,335 | 7 |
| Mar-93 | $342,422 | $353,517 | $32,321 | $33,453 | $8,485 | $8,788 | $1,041,627 | $1,075,393 | 8 |
| Apr-93 | $280,370 | $289,268 | $10,158 | $10,514 | $3,771 | $3,906 | $829,863 | $855,769 | 9 |
| May-93 | $220,790 | $227,765 | $10,158 | $10,514 | $943 | $976 | $672,358 | $693,027 | 10 |
| Jun-93 | $168,970 | $174,275 | $7,388 | $7,646 | $2,828 | $2,929 | $601,407 | $619,435 | 11 |
| Jul-93 | $149,911 | $154,617 | $3,694 | $3,823 | $4,714 | $4,882 | $546,019 | $562,260 | 12 |
| Aug-93 | $148,209 | $152,854 | $5,541 | $5,735 | $2,828 | $2,929 | $532,602 | $548,413 | 13 |
| Sep-93 | $163,774 | $168,916 | $7,388 | $7,646 | $2,828 | $2,929 | $543,317 | $559,476 | 14 |
| Oct-93 | $211,215 | $217,900 | $6,464 | $6,691 | $3,771 | $3,906 | $565,684 | $582,779 | 15 |
| Nov-93 | $329,909 | $340,592 | $12,005 | $12,425 | $3,771 | $3,906 | $748,899 | $773,191 | 16 |
| Dec-93 | $427,516 | $441,377 | $25,857 | $26,763 | $8,485 | $8,788 | $1,134,293 | $1,171,068 | 17 |
| Jan-94 | $466,989 | $482,148 | $37,862 | $39,188 | $15,054 | $15,622 | $1,295,417 | $1,337,397 | 18 |
| Feb-94 | $350,624 | $361,991 | $23,086 | $23,895 | $16,027 | $16,599 | $1,195,589 | $1,234,335 | 19 |
| Mar-94 | $342,422 | $353,517 | $32,321 | $33,453 | $8,485 | $8,788 | $1,041,627 | $1,075,393 | 20 |
| Apr-94 | $280,370 | $289,268 | $10,158 | $10,514 | $3,771 | $3,906 | $829,863 | $855,769 | 21 |
| May-94 | $220,790 | $227,765 | $10,158 | $10,514 | $943 | $976 | $572,358 | $693,027 | 22 |
| Jun-94 | $168,970 | $174,275 | $7,388 | $7,646 | $2,828 | $2,929 | $601,407 | $619,435 | 23 |
| Jul-94 | $149,911 | $154,617 | $3,694 | $3,823 | $4,714 | $4,882 | $546,019 | $562,260 | 24 |
| TOTAL | $6,519,463 | $5,724,444 | $363,842 | $376,588 | $147,073 | $152,317 | $19,333,782 | $19,942,117 | 25 |
| Vol. Charge ($/th) | 0.00515 | 0.00531 | 0.00551 | 0.00571 | 0.00563 | 0.00583 | 0.00533 | 0.00550 | 26 |

(END OF APPENDIX I)