Decision 00-02-046 February 17, 2000

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 1999. (U 39 M)	Application 97-12-020 (Filed December 12, 1997)
Investigation into the Reasonableness of Expenses Related to the Out-Of-Service Status of Pacific Gas and Electric Company's El Dorado Hydroelectric Project and the Need to Reduce Electric Rates Related To This Non-Functioning Electric Generating Facility.	Investigation 97-11-026 (Filed November 19, 1997)
Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Decrease its Rates and Charges for Electric and Gas Service, and Increase Rates and Charges for Pipeline Expansion Service. (Electric and Gas) (U 39 M)	Application 94-12-005 (Filed December 9, 1994)
Order Instituting Investigation Into Rates, Charges, and Practices of Pacific Gas and Electric Company.	Investigation 95-02-015 (Filed February 22, 1995)

(See Appendix A for Appearances.)

OPINION

1. Summary

In this general rate case (GRC) decision, the Commission establishes the authorized base electric and gas revenue requirements for Pacific Gas and Electric Company (PG&E) for the 1999 test year. We have approached our responsibilities in this case with the intention that PG&E receive a level of revenue for its monopoly distribution services that will assure its customers safe, reliable and responsive service under conditions of prudent management, while assuring PG&E's ability to earn its authorized rate of return, again assuming prudent and effective management. We do not intend to place safety, reliability or responsiveness of PG&E's service at risk through underfunding activities, programs and services. At the same time, the magnitude of PG&E's initial proposed increase in rates for services that California customers have received for decades, and the evidence brought forward by ratepayer representatives of anomalous behavior by PG&E, have convinced us that we must be especially vigilant in assuring that customers in fact get what they are paying for.

Initially PG&E proposed total revenues of $2.629 billion for the Electric Department, an increase of $686 million (35.3%) above presently authorized revenues. This decision grants PG&E's motion to withdraw an estimated $37.6 million in revenue requirements for electric industry restructuring, which reduces PG&E's requested electric increase to $648.4 million, approximately 33.3% above presently authorized levels. PG&E proposed total revenues of $1.192 billion for the Gas Department, an increase of $377 million (46.3%) above presently authorized revenues levels. The Commission finds that while it has justified its requests in part, PG&E has requested revenues above the levels necessary to provide safe, reliable, and responsive public utility service. We therefore substantially reduce PG&E's rate increase proposal.

Incorporating the authorized cost of capital for 1999 (Decision 99-06-057, issued June 15, 1999) this decision grants revenue increases of 377 million (19.7%) for electric distribution service and $92 million (11.6%) for gas distribution service over the levels authorized in PG&E's last general rate case for Test Year 1996. These increases are offset by the expiration of $241 million in legislatively mandated electric revenues specifically applicable to reliability-related activities. Public Utilities Code Section 368(e). The net impact will be increases of $136 million in electric revenues over current effective levels (7.1%), and an increase of $92.5 million (4.9%) in gas revenues over current authorized and effective levels. This would be about nine cents a day for the average residential customer.

Customer electric rates are not immediately affected by the authorized revenue changes due to the general rate freeze, and the 10% rate reduction for residential and small commercial customers which are currently in effect pursuant to Assembly Bill (AB) 1890. Nevertheless, the impact of the changes in authorized electric distribution revenue requirement on future rates is potentially significant for both PG&E and its customers. Each dollar of electric distribution revenue increase will reduce overall revenues available for transition cost recovery through the Competition Transition Charge (CTC), and possibly affect the duration of the legislatively-mandated electric rate freeze.

Overall, PG&E's bundled gas rates are changed by this decision as shown in the following table:

Service Class	Changes in Annual Revenues ($000's)	Revenue Change Percent
Non-Gas Accord Customers		
Residential	$76,853	6.1
Small Commercial	11,907	3.5
Large Commercial	508	3.4
Industrial Distribution	3,186	5.6
Gas Accord Customers		
Industrial Transmission	-143	-0.2
Electric Generation	157	0.2
Cogeneration	74	0.2
Wholesale	0	0
Total Change	$92,543	4.9%

As a result of today's order only, a residential gas customer using an average of 50 therms per month on a year-round basis would see average monthly bill increases of $1.56. However, the revenue changes authorized by this order will be consolidated with other authorized gas revenue requirement changes pursuant to the 1999 Annual True-up of Balancing Accounts, and the net impact on gas bills will be different.

By D.98-12-078 dated December 17, 1998, PG&E was conditionally authorized to record the revenue increases proposed in this GRC, on an interim basis, in appropriate electric and gas balancing accounts. As a result of that authorization, the 1999 base revenues authorized today can be made effective as of January 1, 1999. Gas and electric distribution revenue levels in effect on

December 31, 1998 will be increased by a net $229 million dollars; the authorized increase of $469 million offset in part by expiration of $241 million in temporary legislatively mandated reliability-related electric revenues.

PG&E's request for authority to file attrition rate adjustments for the years 2000 and 2001 is denied in part: there will be no attrition in 2000; an attrition adjustment for 2001 is granted in accordance with the provisions of today's order.

On November 13, 1998, PG&E filed Application (A.) 98-11-023 for approval of performance based ratemaking (PBR) mechanisms for electric and gas distribution service with a proposed effective date of January 1, 2000. A PBR mechanism may defer the need for a future GRC for PG&E. However, we do not make such a determination at this time. Instead, we direct PG&E to file a GRC for a 2002 test year, subject to further order of the Commission, in accordance with the Rate Case Plan, D.89-01-040 and decisions interpreting it. The PBR proceeding may go forward with a narrowed scope, subject to further order of the Commission. That proceeding will formally adopt certain performance and reliability standards currently in use by the other utilities. The design, productivity assumptions, and financial structure for PBR will have to await the establishment of a more solid starting point in the 2002 GRC.

In this order, we also establish standards for customer service in several areas of immediate interest to residential ratepayers, including the timeliness of response to complaints and outages. To make these standards effective we are adopting a set of consumer remedies as proposed by the Office of ratepayer Advocates and The Utility Reform Network (TURN) (see Chapter 6).

In this order we are authorizing significant increases in revenue to support enhanced vegetation management programs and distribution capital spending. To assure the public that these increased revenues are being effectively managed, we are putting in place measures to assure accountability by PG&E for the programs. In the case of vegetation management we are requiring a one-way balancing account to assure close matching of authorized revenues and actual expenditures. In the case of capital spending we are directing our Energy Division to conduct an audit of 1999 distribution capital additions to develop a clear picture of current capital spending patterns.

D.97-12-096 established a revenue requirement mechanism applicable to PG&E's hydroelectric and geothermal generation facilities which have not been divested or otherwise market-valued. Today's order updates the revenue requirement and modifies the mechanism to include forecast ratemaking for capital-related costs.

In this order, the Commission also reviews the funding requirements for future decommissioning of PG&E's nuclear generating facilities at Diablo Canyon and Humboldt Bay. The Commission determines that the decommissioning trust funds for these facilities are adequately funded at this time, based upon conservative assumptions about future decommissioning and nuclear waste disposal costs, and about investment performance of the funds' assets. This order continues accruals into the decommissioning trust at somewhat reduced levels. PG&E is authorized to expend up to $7 million in Humboldt Bay Unit 3 decommissioning trust funds to secure regulatory authorization for on-site storage of spent fuel. Such authorization would enable early decommissioning of Unit 3.

The Commission approves a new plan pursuant to which PG&E will assist new agricultural customers to make informed decisions in selecting their most cost-effective rate option.

2. Background

2.1 Basis For This GRC

PG&E filed its last GRC in December 1994 for a 1996 test year. In December 1995, at the time of our decision in that proceeding, we thought that PG&E would be subject to PBR by now. (D.95-12-055, 63 CPUC2d 570, 582.) PG&E had already filed a PBR application, and even though it withdrew that proposal, we understood that PG&E would be resubmitting a PBR proposal which complemented our electric industry restructuring policy. (*Id.*, 585.) We therefore expected that there would be no more GRC reviews for PG&E. (*Id.*)

With the passage of AB 1890 (Stats. 1996, Ch. 854)) in September 1996, and specifically Public Utilities Code Section 368, PG&E and other electric corporations were required to propose plans for the recovery of certain of their uneconomic costs for generation-related assets and obligations. Among other things, each utility's cost recovery plan provides for a general freeze of electric rates for all customer classes at their June 10, 1996 levels. The freeze is to remain in effect until Commission-authorized generation-related costs have been recovered, but no later than March 31, 2002. The cost recovery plan also provides that beginning in 1998 and continuing through the end of 2002, electric rates for residential and small commercial customers will be reduced by no less than 10% from their June 10, 1996 levels. (See D.96-12-077.)

Section 368(e) further provides that:

> "(e) As to an electrical corporation that is also a gas corporation serving more than four million California customers, so long as any cost recovery plan adopted in accordance with this section satisfies subdivision (a), it shall also provide for annual increases in base revenues, effective January 1, 1997, and January 1, 1998, equal to the inflation rate for the prior year plus two percentage points, as

> measured by the consumer price index. The increase shall do both of the following:
>
> "(1) Remain in effect pending the next general rate case review, which shall be filed not later than December 31, 1997, for rates that would become effective in January 1999. For purposes of any commission-approved performance-based ratemaking mechanism or general rate case review, the increases in base revenue authorized by this subdivision shall create no presumption that the level of base revenue reflecting those increases constitute the appropriate starting point for subsequent revenues.
>
> "(2) Be used by the utility for the purposes of enhancing its transmission and distribution system safety and reliability, including, but not limited to, vegetation management and emergency response. To the extent the revenues are not expended for system safety and reliability, they shall be credited against subsequent safety and reliability base revenue requirements. Any excess revenues carried over shall not be used to pay any monetary sanctions imposed by the commission." (Emphasis added.)

This legislation applies only, and specifically, to PG&E. The Legislature provided for base revenue increases in 1997 and 1998 without any review by the Commission for reasonableness or prudence, and it required PG&E to file an application for a test year 1999 GRC by December 31, 1997. This proceeding results in part from these legislative directives. Commission review of Section 368(e) expenditures is presently pending in A.99-03-039.

2.2 Overview of PG&E's GRC Application

On September 15, 1997, PG&E tendered its Notice of Intent (NOI) to file a test year 1999 GRC application. The Commission's Executive Director conditionally accepted the NOI for filing on November 3, 1997. PG&E filed its formal application, A.97-12-020, on December 12, 1997.

When it filed this application, PG&E sought gross base revenue increases (from the revenues in effect on October 1, 1997) effective January 1, 1999 in the amounts of $693 million for its Electric Department (California-jurisdictional) and $501 million for its Gas Department. Relative to the current GRC-related revenues, PG&E's proposed increases were 42% for the Electric Department and 61% for the Gas Department. As shown in the following table, PG&E has modified its requested base revenue requirement increases during the course of this proceeding, including in a major revision to its application submitted in March and April 1998 (March Update).

PG&E's Requested Base Revenue Increases for 1999 ($Millions)
(Relative to Present Revenues Including Section 368(e) Funding)

	Electric Department	Gas Department	Total Request
NOI (September 1997)	703	506	1,209
Application (December 1997)	693	501	1,193
March Update (April 1998)	572	460	1,032
Comparison Exhibit (October 1998)	445	377	822

PG&E does not seek electric rate changes in this GRC due to the statutory rate freeze. PG&E also seeks no changes in gas transmission and storage rates which are subject to the Gas Accord adopted in D.97-08-055 through the year 2002. PG&E initially sought overall increases of 25% for bundled gas rates, i.e., for total gas rates including rate components not subject to adjustment in this proceeding. In its notices to the public, PG&E stated that its proposed gas rate increases would raise average residential gas bills by $5.16, to a total of $24.31 per month in summer months, and by $17.15, to a total of $80.88 per month in winter months.

PG&E seeks authorization to file attrition rate adjustments for the years 2000 and 2001, the second and third years of the GRC cycle. Attrition adjustments would be filed for costs which are not subject to other, similarly-purposed programs. The attrition proposal is presented by PG&E as an alternative to the distribution PBR mechanism which PG&E has proposed (in A.98-11-023) for implementation in 2000. At the time of its application, PG&E estimated its year 2000 attrition request at $148 million and $30 million for electric and gas service, respectively. For 2001, PG&E's estimated attrition request was $120 million and $27 million for electric and gas service, respectively.

Anticipating changes in the electric and gas industries that will result in the disaggregation of its revenue requirements, PG&E presented its application in a traditional bundled format and, consistent with D.97-08-056, in an unbundled format with revenues separated among eight unbundled cost categories (UCCs). The eight UCCs are electric generation, electric transmission, electric distribution and customer service, electric public purpose, gas transmission and storage, Line 401-Pipeline Expansion, gas distribution and customer service, and gas public purpose.

PG&E's original request for the Electric Department included revenues for electric distribution and customer service, electric public purpose programs, and nuclear decommissioning. It also included the revenue requirement associated with operating and maintaining Humboldt Bay Power Plants (Humboldt) Units 1 and 2 and SAFSTOR maintenance costs associated with maintaining Humboldt

Unit 3.[1] Pending resolution of divestiture and other proceedings affecting generation revenue requirements, PG&E's request in this application includes other generation revenues as well. Pursuant to D.97-12-096, hydroelectric and geothermal generation plants which have not been divested or otherwise undergone market valuation are subject to a revenue requirement mechanism which determines the revenue available for transition cost recovery. In accordance with D.97-12-096, this GRC considers updates and adjustments to the hydroelectric / geothermal revenue requirement mechanism.[2]

For the Gas Department, PG&E requests revenue adjustments for gas distribution and customer service and gas public purpose programs only.

While PG&E does not request revenue adjustments in this GRC for electric transmission, gas transmission and storage, or Line 401, PG&E included a showing of its bundled base revenue requirements for the Electric and Gas Departments to provide a basis for allocation of costs to appropriate categories.

2.3 El Dorado Project Investigation

By order dated November 19, 1997, the Commission instituted Investigation (I.) 97-11-026 into the out-of-service status of PG&E's El Dorado Project, a 21 megawatt hydroelectric facility owned and operated by PG&E. The project was taken out of service due to extensive damage caused by flooding during the 1997 New Year's storm. The investigation was instituted pursuant to

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1 SAFSTOR is a condition of monitored safe storage in which the nuclear unit will be maintained until spent fuel is removed from the site and the facility is dismantled.

2 D.99-04-026 dated April 1, 1999 authorized PG&E to transfer and sell certain generating facilities, including its Geysers Geothermal Lake County and Sonoma County Plants, subject to mitigation and other conditions. Thus, the ratemaking mechanism will apply to PG&E's hydroelectric generation.

Section 455.5(c), which requires that the Commission undertake such an investigation when any portion of a utility's generation or production facilities has been out of service for nine or more consecutive months. Section 455.5(c) also requires that rates associated with the plant be made subject to refund as of the date of the order and that the hearing on the investigation be consolidated with the utility's next general rate proceeding. Accordingly, A.97-12-020 and I.97-11-026 were consolidated.

The El Dorado investigation includes but is not limited to the reasonableness of the operating expenses and return on investment associated with the idle facilities, and the reduction of rates to reflect any disallowed expenses for the idle plant. The Commission ordered PG&E to establish a memorandum account to track all costs associated with the project pending the outcome of the investigation.

2.4 Rehearing of PG&E's 1996 GRC

By D.98-12-096 dated December 17, 1998, the Commission addressed a PG&E application for rehearing of D.95-12-055, which resolved revenue requirements issues in PG&E's test year 1996 GRC (A.94-12-005 / I.95-02-015). Among other things, the Commission granted limited rehearing for the purpose of further considering pension funding policy for PG&E. It then stated:

> "We note that in the currently ongoing PG&E GRC proceeding for test year 1999 (Application 97-12-020 / I.97-11-026), PG&E appears to take the same position on pension funding policy that it did in the case at issue here. The same is true for ORA. Hearings have been completed in the current GRC, the issues are virtually identical, and the [Administrative Law Judge (ALJ)] has all of the arguments presented in that case before him for determination. For reasons of economy and efficiency, we will thus consolidate the rehearing on this issue with the current case." (D.98-12-096, p. 3.)

2.5 Parties

Of the 32 parties who entered appearances, 17 participated substantively in the evidentiary hearings, filed briefs, or both. Testimony was presented by PG&E, the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), James Weil, Enron Corp. (Enron), the Agricultural Energy Consumers Association (AECA), the California City-County Streetlight Association (CAL-SLA), the Redwood Alliance, the California Farm Bureau Federation (CFBF), the California League of Food Processors (CLFP), Local 1245 of the International Brotherhood of Electrical Workers (IBEW), and the Federal Executive Agencies (FEA). Each of these parties participated through cross-examination and briefing, as did Southern California Edison Company (Edison) and University of California and California State University (UC / CSU). Ron Knecht and the Coalition of California Utility Employees (CCUE) cross-examined witnesses, and the California Department of General Services (DGS) filed a reply brief.

2.6 Procedural History

Prehearing conferences were held on January 29 and August 17, 1998. A conference on the status of results of operations modeling issues was held on November 17, 1998. Public participation hearings were held in Salinas, San Luis Obispo, Bakersfield, Clovis, Merced, Eureka, Chico, Woodland, Placerville, San Francisco, and San Jose during the weeks of March 30, April 13, and April 20, 1998. Both afternoon and evening sessions were held at the majority of these locations. Evidentiary hearings on the parties' direct and rebuttal showings were held on 39 days, from August 24 to October 16, 1998 and on December 14 , 1998. Testimony was received from more than 100 witnesses, and nearly 500 exhibits were received in evidence. All issues are ready for consideration with the exception of the El Dorado Project ratemaking issues and the Section 368(e) funding issues discussed elsewhere in this opinion. Oral argument was scheduled before the Commission.

Altogether, the Commission held two prehearing conferences and 50 days of hearings (including public participation hearings) in this matter. The Assigned Commissioner was in attendance at the first prehearing conference and on seven hearing days. As discussed in D.98-12-078, it was necessary to modify the Rate Case Plan schedule by extending the period for ORA and other parties to serve their prepared testimony and by adjusting other elements of the schedule accordingly. The schedule was again suspended to allow adequate time for review of the extensive evidentiary record. While this decision is issued after the 18-month time period set forth in Senate Bill (SB) 960 (Stats. 1996, Ch. 856) as computed from the date the original application was filed, it is issued approximately 22 months after the complete submission by PG&E of the "March Update" in April 1998, when PG&E in effect perfected its application.[3]

The April 7, 1998 *Assigned Commissioner's Ruling Pursuant to Rule 6(d)* (Scoping ACR) designated the assigned Administrative Law Judge (ALJ) as the principal hearing officer as defined in Rule 5(l) of the Rule of Practice and Procedure (Rules). It also determined that this GRC is a ratesetting proceeding. Pursuant to Rule 5(k)(2), the principal hearing officer is the presiding officer for this proceeding. Accordingly, the proposed decision of the ALJ was issued pursuant to Rule 8.1(b), which requires issuance of a proposed decision by the presiding officer.

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3 In fact, in some respects PG&E did not perfect its application until much later in the proceeding. A prime example is PG&E's showing on Administrative and General (A&G) expenses.

This proceeding is more than a year behind schedule. An important one is that after the close of the record, we determined that evaluation of the impact of the parties' positions on PG&E's revenue requirements required use of financial and operations computer models beyond the capability of this Commission's Energy Division staff. Nearly three months were taken up by training of staff and modeling of various revenue requirement scenarios on PG&E proprietary models. This is "black box regulation" of a type we do not intend to perpetuate. It has placed PG&E at risk for retroactive rate reductions (to January 1, 1999, under the terms of D.98-12-078. It has delayed the translation of revenue requirements into rates on which customers can depend at a time which is critical to the transition to a competitive energy market. We intend to improve this procedure for future cases.

While most of the issues raised in this consolidated proceeding are resolved by today's order, or are more appropriately addressed in other proceedings, we have deferred consideration of the ratemaking consequences of the out-of-service status of the El Dorado project. In addition, today's order directs ORA to make compliance filings reporting on consultant costs and a verification audit. Accordingly, these dockets will remain open pending disposition of these matters.

2.7 Scope of Proceeding

As noted above in the description of PG&E's application, this is primarily a proceeding to determine the revenues required for PG&E's utility distribution services and related customer service functions. It also considers certain generation-related costs pursuant to earlier Commission decisions, as well as public purpose programs. It covers the costs of non-fuel operations, operation and maintenance (O&M) and A&G expenses, depreciation, taxes, and return on rate base for the Gas and Electric Departments. It does not cover costs associated with the Diablo Canyon Nuclear Power Plant (Diablo Canyon) except for expenses associated with nuclear decommissioning.

For the most part, the scope of this proceeding was defined by PG&E's application; our Order Instituting Investigation (I.) 97-11-026; D.96-12-077 and Resolution E-3516, which provided that this GRC is the forum to consider issues related to Section 368(e) safety and reliability funding authorized for 1997 and 1998 (which issues are new being considered in A.99-03-039); and D.98-12-096, which consolidated the rehearing of the pension funding policy issue from PG&E's 1996 GRC with this proceeding. As stated in the Scoping ACR, the overarching objective is to determine the reasonable base revenue requirements for PG&E's Electric and Gas departments. As also noted in the Scoping ACR, PG&E has stipulated and is on notice that the scope of this proceeding includes possible reductions in revenue requirements and rates or components thereof.

With one exception, this proceeding excludes consideration of marginal cost, revenue allocation and rate design issues, which will constitute the second major phase of this GRC. These matters will be addressed in A.99-03-014, filed by PG&E on March 5, 1999. D.97-12-049 required that PG&E develop a systematic plan for informing new agricultural accounts of their most cost-effective rate schedule and to include the plan in this proceeding. We address this single rate design issue herein.

2.8 Comparison Exhibit

The Rate Case Plan requires that "[a]n exhibit comparing the [ORA] and utility final positions / numbers shall be jointly prepared by [ORA] and the utility..." (30 CPUC2d 576, 604.) Accordingly, in coordination with ORA, PG&E

developed a comparison exhibit (Exhibit 474) upon conclusion of the evidentiary hearings. PG&E served it on the parties on October 30, 1998.

The purpose of the comparison exhibit is to summarize and compare PG&E's and ORA's positions, as indicated in the record, as of the conclusion of hearings. As Enron notes, it does not reflect the positions of other parties. The exhibit includes summaries of the results of operations calculations for PG&E's Gas and Electric Departments based on PG&E's and ORA's forecasts for 1999; account-by-account comparisons of the forecasts for O&M and A&G expenses; and additional information related to plant, rate base, and the unbundling of the revenue requirement into UCCs.

In its opening brief, ORA stated that it had found areas of significant difference between its showing in this case and PG&E's representation of its position in the comparison exhibit. ORA asserted that PG&E's presentation of ORA's estimates in the area of CPUC jurisdiction were not consistent with ORA's understanding of the record or subsequent agreements with PG&E. According to ORA, PG&E also misrepresented its positions on Transmission Level Direct Connects, Third Party Generation ties, and Humboldt - SAFSTOR. ORA stated that it also found factual errors in the following areas: Other Production, Transmission Expense, A&G Expense, Customer Accounts, Common Plant, Plant, Depreciation, and Rate Base.

PG&E replies that while it regrets if any of ORA's positions were misstated, misinterpreted, or otherwise presented inaccurately, it made every reasonable attempt to develop the comparison exhibit in strict accordance with the most current information on the record for both parties' positions and on all issues. PG&E notes that ORA's results of operations showing was limited to testimony and summary tables only; that it did not have certain of ORA's workpapers; that ORA did not respond to certain of its data requests; and that

ORA defined what it meant by CPUC Jurisdiction for the first time in its opening brief.

Discussion

While it is regrettable that the comparison exhibit does not accurately reflect ORA's positions in all respects, there is no evidence that PG&E has failed to substantially comply with the requirements of the RCP regarding comparison exhibits. The exhibit was "jointly prepared" by PG&E and ORA in the sense that PG&E coordinated with ORA, although it is also clear that the degree of coordination was unfortunately limited. We suspect that given more time for such coordination, these problems with the comparison exhibit might have been avoided.

We note that ORA believes that at least some of the outstanding differences involve coordination as opposed to policy issues. ORA was of the opinion that these coordination issues could be resolved with further technical discussions. We also observe that ORA has had an opportunity in its opening and reply briefs to clarify its positions on matters represented in the comparison exhibit, and to advise us of its positions with reference to the record. Moreover, we note that ORA took advantage of that opportunity in its opening brief. As explained by ORA, its discussion clarifies the positions it believes were misstated in the comparison exhibit. In this respect, we note that the comparison exhibit has fulfilled an important purpose by disclosing discrepancies in the parties' understanding of each others' positions, and by helping to clarify the parties' positions for the record. We bear in mind ORA's concerns regarding the comparison exhibit as we address issues for which ORA disputes the comparison exhibit's representation of its positions.

2.9 Organization of This Decision

Pursuant to the ALJ's direction at the conclusion of evidentiary hearings in October 1998, several of the parties collaborated on the development of a common outline to be used by all parties in their briefs. This decision generally follows the order of the common briefing outline, although it uses a somewhat different format.

Litigation of some issues, primarily those related to PG&E's internally-developed Customer Information System (CIS), required consideration of data deemed confidential by PG&E based on allegations of protected trade secrets. Where we address confidential information, we do so in a manner that does not require unnecessary public disclosure.

Where appropriate, headings for sections which address one or more Federal Energy Regulatory Commission (FERC) accounts include the FERC account number.

2.10 Proposed and Alternate Decisions

On October 18, 1999 the Administrative Law Judge assigned to this proceeding issued a Proposed Decision (PD) in this proceeding. Comments on the PD were received on November 8, 1999 and oral argument on the proposed decision was conducted before the full Commission on November 25, 1999. Most of the active parties filed comments on the PD. To some extent the comments on the PD and reply comments reargued positions taken in the briefs of the respective parties.

On January 14, 2000, Commissioner Carl Wood mailed this decision to parties as an Alternate Decision to the Proposed Decision of ALJ Mark Wetzell. Comments on the Alternate Decision were received on January 25, 2000 from ORA, TURN, PG&E, CCUE, Weil, CLFP, AECA, CFBF, Enron and FEA. To some extent we accept or reject proposed revisions to the Alternate Decision without comment or discussion. Where such discussion is necessary or appropriate, we address a proposed revision in the section of the decision where the subject matter appears.

2.11 The Participation of Commissioner Wood

On January 18, 2000, Commissioner Wood sent a letter to all parties of record outlining why he believes his prior association with the Coalition of California Utility Employees (CCUE), a party in this proceeding, does not present a conflict of interest for him in terms of his participation in this case. His letter gave parties until January 27, 2000 to comment in writing on his position. His letter directed an objecting party to substantiate its objections with appropriate legal analysis, including citations to relevant legal authority. The only comments received were from James Weil, who appears as an individual customer of PG&E in this proceeding.

Weil contends Commissioner Wood’s prior association with CCUE and with utility labor unions creates a conflict of interest, both as a matter of law and appearance. He objects to Commissioner Wood’s participation in this proceeding, in A.98-09-003 et al. (the first annual transition cost proceeding), and in all other Commission proceedings in which CCUE or any utility labor organization is a party. His sole citations to legal authority are to Black’s Law Dictionary (for a definition of “interest”) and Sections 87400 et seq. of the Political Reform Act (Cal. Gov. Code §§ 81000-91015), which deal with disqualification of former public officers and employees.

We find Weil’s arguments to be without merit.

The conflict as a matter of law exists, Weil argues, because while Commissioner Wood stated he had not participated in formulating CCUE’s position in this case, he does not state whether he is still a union member,[4] nor does he state whether he intends to join or might join a utility union or CCUE after leaving the Commission. In Weil's view, the mere possibility that Commissioner Wood may re-establish a future association with utility labor unions is enough to presently create an unlawful conflict of interest for him.

However, that is not the standard. The cases do not speculate about whether a prior association with a party will be resumed at some point in the future. Courts have consistently held that a public official's prior association with a party in a case is not by itself enough to require disqualification. It must be shown that the prior association has led to actual bias or, in certain situations, a high probability of actual bias, often discussed by the federal courts in terms of the public official's prejudgment of the facts, to the extent that he or she cannot be considered able to make an impartial decision. This requires a detailed analysis of the concrete facts presented by each case. See, for example, *Gai v. City of Selma* (1998) 68 Cal.App.4th 213, 219-222; Lead Industries Ass'n v. Environmental Protection Agency (D.C.Cir. 1980) 647 F.2d 1130, 1175-1179; cert. den. 449 U.S. 1042 (1980)).

Weil has not presented facts showing that Commissioner Wood has demonstrated actual bias or prejudgment of any of the issues in this proceeding. Rather, Weil presents only his opinion that prior association with the utility labor unions and CCUE, and hypothecated future association with these entities must necessarily equate to bias on Commissioner Wood's part. These are not factual assertions. Wood was appointed at least in part because of his convictions, not in spite of them.

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[4] In fact, Commissioner Wood is <u>not</u> still a union member.

In terms of the appearance of a conflict, Weil cites to the Political Reform Act, which, in part, imposes strict rules on a former Commissioner's or designated employee's representation of parties and communications with the Commission after leaving state employment. (See especially Gov. Code § 87401.) Weil argues that while the reverse situation -- where a person acting on behalf of another person in a Commission proceeding then becomes a Commissioner or designated employee -- is not covered by that statute the Commission should apply a similar principle by analogy. We decline to do so.

Weil cites as precedent the example of Commissioner G. Mitchell Wilk, who, during the first year of his term, abstained from voting on matters involving the Southern California Gas Company (SoCalGas). Commissioner Wilk did so, according to Weil, not because he might work for the utility after leaving the Commission, but because of "his connections with the utility prior to appointment as a Commissioner." (Weil Comments, p. 4.) Because Commissioner Wood was involved with CCUE generally and with its participation in the instant proceeding before he became a Commissioner, Weil argues he should not participate in any matters in which CCUE or any utility labor organization is a party for at least one year.

The Political Reform Act addresses financial conflicts of interest. It prohibits a public official from participating in proceedings in which a source of income to that official has a material financial interest for a period of one year after the last income was received by the official. A former employer of an official would normally be considered a source of income to that official. However, the Fair Political Practices Commission, in implementing the Political Reform Act, has created an exception under which a former employer is not a source of income to a public official if:

> "All income from the employer was received by or accrued to the public official prior to the time he or she became a public official; the income was received in the normal course of the previous employment; and there was no expectation by the public official at the time he or she assumed office of renewed employment with the former employer." (Fair Political Practices Commission Regulation 18703.3(b).)

No utility labor union is a source of income to Commissioner Wood. He was employed by the Utility Workers Union of America (UWUA), Local 246, until early 1997, and by the national UWUA from 1997 to mid June, 1999, shortly before he was appointed to the Commission. He resigned from employment with Local 246 when he began employment for the national UWUA. He resigned from employment with the national union on June 20, 1999, simultaneous with resigning from CCUE. While both unions were a source of income to him while he was employed by them, as of his resignation dates those financial interests ceased to exist. At the time of Commissioner Wood's appointment, our General Counsel verified that Commissioner Wood's situation satisfied all of the requirements of the former employer exception.

Thus, the Political Reform Act does deal with the situation of a person who leaves outside employment and becomes a state official. Furthermore, the regulations implementing that Act specifically deal with the possibility that such a person might return to that outside employment after leaving state service. In that situation, the regulations specifically provide that there is no disqualifying conflict if the public official has no expectation of renewed employment with the former employer. Commissioner Wood has no such expectation and so there is no disqualifying conflict.

Furthermore, CCUE is not a source of income to Commissioner Wood. He was an officer of CCUE solely by virtue of the fact that he worked for the

UWUA. He never had a direct financial interest in CCUE, since his position was unpaid.

Finally, Commissioner Wilk's situation is not comparable to Commissioner Wood's. During much of his first year at the Commission, Commissioner Wilk could not participate in matters affecting SoCalGas because he had a disqualifying financial interest in SoCalGas under the Political Reform Act, due to his receipt of gifts from SoCalGas before being appointed to the Commission. In contrast, Commissioner Wood has no disqualifying financial interest in CCUE or any utility labor unions under the statute. While Commissioner Wood's former association with these organizations may have given him a particular perspective on the issues, without a clear showing that this association has created actual bias, or a high probability of actual bias, he is not required to disqualify himself from this proceeding or any other matters that might affect CCUE or utility labor unions generally.

3. Public Participation

Largely in response to customer bill insert notices provided by PG&E, the Commission's Public Advisor received hundreds of letters and electronic mail messages from PG&E customers with comments on PG&E's application. The Commission also received numerous communications, many of which were submitted in form letter format, from civic leaders and from economic development, community improvement, disaster relief, utility employee, and other organizations from throughout PG&E's service territory.

Comments ranged from statements of total opposition to PG&E's requested increases, and recommendations for outright denial of the application, on the one hand, to support for PG&E and recognition of the importance of safe and reliable utility services and the ability of PG&E to provide such services, as well as the beneficial community service roles that it fulfills, on the other hand. Without attempting to state all of the concerns and positions presented, we summarize typical comments, including those that were made frequently and in some cases forcefully to the Commission:

> A modest gas rate increase (3% to 7%) might be appropriate, but PG&E's proposed 25% rate increase is way out of line, and is not justified by inflation or by natural gas prices.
>
> By proposing a 25% gas rate increase, it appears that PG&E is attempting to offset the effect on the company of the statutory 10% electric rate reduction and subsidize electric operations on the basis of gas rates alone. (This is a particular concern of gas-only customers and customers who say that PG&E encouraged them to convert from electric to gas appliances.)
>
> PG&E's rates are among the highest in the nation, and the company is already earning high or adequate profits.
>
> Customers with fixed or low incomes will be harmed by a large gas rate increase, as will elderly customers who require more heating than other customers.
>
> PG&E should do more to cut costs and become more efficient before asking the Commission for rate increases.
>
> It seems that PG&E is constantly asking for rate increases.
>
> PG&E has failed to spend previously authorized funds that were earmarked for tree trimming, so the Commission should not authorize additional funding for this purpose.
>
> Customers should receive the promised savings from energy industry restructuring and deregulation efforts, not more rate increases.
>
> Shareholders, not customers, should pay for nuclear decommissioning.

> As a result of the proposed electric revenue increase and the tracking of the increased amounts in regulatory accounts, a significant electric rate increase may occur after the rate freeze is over.
>
> While no one wants rate increases, they are necessary. Dependable utility services are vital to the state's economy, and the Commission should ensure that PG&E has the funding needed to maintain its utility distribution system for safety and reliability and to provide responsive customer service.
>
> PG&E may have to lay off workers and reduce service quality if the requested rate increases are not granted.
>
> PG&E provides good, affordable utility service.
>
> PG&E is a good corporate citizen which provides important community services.
>
> Like any business, PG&E must increase prices from time to time.

Some commenters expressed concern about the process that the Commission would use to evaluate PG&E's request. Some are concerned that the Commission operates in a reactive mode by responding to utility applications; that it may not adequately review the request; and that it may authorize excessive revenues. Others simply urged the Commission to carefully review PG&E's requests and grant only the amounts necessary.

Most of these same themes were raised in the public participation hearings in comments offered by more than 250 speakers. While we cannot accord the comments the same weight as evidence presented in sworn testimony of witnesses subject to cross-examination, we value this input and incorporate it into our deliberations. Among other things it helps us to understand the perspective of customers and others who are affected by PG&E's activities, and to recognize, frame, and weigh the public policy issues before us in this GRC.

In pursuing this GRC, PG&E created a "1999 General Rate Case Education Campaign" whose objective was to "[s]upport PG&E's efforts to win approval of its GRC by educating the public and key constituencies about the direct local impacts and benefits funded by the GRC." (Exhibit 70.) Part of the strategy was to encourage support, whether in writing or in Commission hearings, of third-party stakeholders relative to the central themes of the GRC -- safety, reliability, and customer service. Undoubtedly, some of the comments that we received resulted from PG&E's campaign. We prefer comments that appear to be spontaneous in nature and reflective of the independent judgment of ratepayers and other stakeholders.

4. Policy Issues

4.1 The Framework for GRCs

In this case, as in all others brought under the Public Utilities Act, we seek to promote the public interest. This involves balancing the interests of numerous stakeholders -- residential, business and agricultural end-use customers; utility investors and employees; utility managers; providers of energy services; exponents of environmental and social concerns. In this case, which deals with the pricing and quality of electric and gas distribution service, we are dealing with essential services, infrastructure that is critical to the well-being of our entire state. Through local franchises and the orders of this Commission, California has entrusted management of this infrastructure to the stewardship of Pacific Gas and Electric Company, subject to our ongoing regulatory oversight. PG&E is a pervasive presence in our communities, and a vital force in the economy of Northern California. We intend to hold PG&E to a high standard of service quality, and we expect prudent and effective management of the financial and human resources we have placed under its control. Under these conditions we intend to provide sufficient revenues to meet the costs of providing quality distribution service. We seek to strengthen the partnership between the public and PG&E.

PG&E enjoys an effective monopoly in the provision of electric and gas distribution service. (C.f., Pub. Util. Code Sections 330(f) (electric) and 328 and 328.2 (gas, added by Statutes 1999, Ch. 909, effective January 1, 2000).) This means not only that it is the sole provider of the service, but also that it has exclusive control over the costs and conditions of such service and, importantly, control over the information about costs and conditions. In order to prevent abuse of this monopoly and its incidents, the Legislature has given the Commission broad powers of investigation intended to make the real costs and conditions of monopoly service transparent. We exercise those powers to assure the public that the prices they pay for monopoly service are in fact just and reasonable, that they are in fact reasonably related to costs prudently incurred by efficient, conscientious managers to provide the quality of service we expect. This is at the core of our responsibilities.

This case has severely tested our ability to employ these tools to reach a just and reasonable result.[5] After more than two years of proceedings, tens of thousands of pages of testimony, thousands of pages of briefs and arguments, months of confidential evaluation by the Energy Division, we are still faced with making significant decisions about PG&E's revenue requirements, accounting

[5] Noting the duration of hearings and the number of exhibits, Enron referred to "the enormity of the record." (Enron Opening Brief, p. 3.) The *American Heritage Dictionary, Office Edition,* defines enormity as "1. Extreme wickedness. 2. A monstrous offense or evil; outrage." We, and the ALJ who developed and reviewed the record, cannot disagree with this characterization.

and costing practices and service levels, based on judgements that are informed by less than clear or precise information. This is not for lack of effort by our staff, ORA, PG&E, or the other parties. They have all played the regulatory game as they understand it. But the game disserves us as decision-makers and disserves the public, who want and deserve meaningful assurance that the prices they are paying are fair and the service they expect will be provided.

Much of the onus for the lengthy, contentious and tendentious process leading up to this decision rests with PG&E. As the moving party in this application, it sets the agenda and the issues. The sheer magnitude of the initial request -- over $1.2 billion dollars annually in additional consumer payments -- initially raised serious concern. As demonstrated overwhelmingly in the hundreds of pages of detailed discussion of programs and costs that follow, there is ample reason to fear that PG&E's claimed costs are systematically inflated, and that PG&E has deliberately inflated them. We are further concerned by PG&E's attempts to reduce funding of independent experts for the Office of Ratepayer Advocates to examine PG&E's justifications for such an enormous increase critically. We expect better of PG&E as a partner in our stewardship of the public interest.

Part of the reason that we are concerned about inflated cost projections is that over the eight-year period between 1987 and 1995 PG&E consistently spent less on electric and gas facility maintenance than we had authorized in previous GRCs, to the tune of nearly $550 million dollars. This could have reflected a consistent error in forecasting that led to our granting authorized revenues above those necessary for adequate service. If so, we should be especially vigilant in this case in our application of estimating methodologies. It also could reflect diversion by PG&E of maintenance funds to other programs and, possibly, systematic underfunding of maintenance. This could further suggest that

PG&E's maintenance and capital expenditures in recent years (1996-97- 98) reflect in part catch-up activities , and therefore should arguably be disregarded in determining the revenues needed to supply adequate service for the test year and the future. This counsels further vigilance.

PG&E contends that adopting such an approach would constitute systematic bias and prejudice in this proceeding. We fundamentally reject this characterization. It is simple prudence and caution. We are extremely impressed with the efforts of ORA and the parties to provide us with alternative approaches to estimating costs and capital requirements that can eliminate the persistent gap between authorized and actual expenditures. Nevertheless, we are concerned that an over-correction in this regard could result in a diminished ability on PG&E's part to respond to the needs of Californians for its monopoly electric and gas distribution service. We do not intend to make such an error.

It is in this sense that the regulatory process has failed us. A zealous and contentious response such as ORA's may be appropriate to a huge proposed rate increase in a context of demonstrated historical underspending on mission-critical programs. But it can also err in the opposite direction, leaving us to make decisions based on a choice between starkly opposing estimates, opinions and litigation postures. We need greater precision in our information and estimates, brought forward in a less cumbersome, burdensome and voluminous manner. For the future we intend to use existing investigative and regulatory tools to simplify the process of getting sound information on which we can make timely decisions.

It appears that PG&E has awakened and smelled the coffee. In its Comments on the Proposed Decision in this proceeding, PG&E has acknowledged that:

> ***PG&E has heard loud and clear from the Commission, customers and the Legislature that its level of service in 1995, when PG&E's last rate case was approved, did not meet either the Commission's or customers' expectation, and that PG&E must improve its service and compliance to meet these expectations***. (Comments, pp. 6-7, emphasis in original.)

We welcome this acknowledgement. PG&E has expended significant sums, much of it ratepayer dollars mandated by the Legislature in AB 1890 and some of it shareholder funds, to improve its quality of service over the past three years to meet our expectations in that regard. We will insist that procedures be put in place to assure that revenues authorized in this decision are spent in ways directly related to providing service quality to customers, so that PG&E can meet our expectations about compliance as well.

4.2 Legal Standards

4.2.1 The Public Utilities Act

Under the Public Utilities Act, our primary purpose "is to insure the public adequate service at reasonable rates without discrimination..." (*Pacific Telephone and Telegraph Company v. Public Utilities Commission* (1950) 34 Cal.2d 822, 826 [215 P.2d 441]; *Pacific Telephone and Telegraph Company v. Public Utilities Commission* (1965) 62 Cal.2d 634, 647 [44 Cal. Rptr. 1, 401 P.2d 353]; *City and County of San Francisco v. Public Utilities Commission* (1971) 6 Cal.3d 119, 126 [98 Cal. Rptr. 286, 490 P.2d 798].) Under Section 451, public utilities may demand and receive only just and reasonable charges, and they must provide "adequate, efficient, just, and reasonable service" in a way that promotes the "safety, health, comfort, and convenience of [their] patrons, employees, and the public." Under Section 454, public utilities must make a showing to the Commission that any proposed rate change is justified, and receive a finding by the Commission to that effect, before making such change. Under Sections 701 and 728, the Commission has the authority to determine what is just and reasonable, and to disallow costs not found to be just and reasonable. In particular, the Commission "has the power to prevent a utility from passing on to the ratepayers unreasonable costs for materials and services by disallowing expenditures that the commission finds unreasonable." (*Pacific Telephone and Telegraph Company v. Public Utilities Commission, et al., supra.*)

Our charge is to ensure that PG&E provides adequate service at just and reasonable rates. As we use the term here, adequate service encompasses all aspects of the utility's service offering, including but not limited to safety, reliability, emergency response, public information services, new customer connections, and customer service. Adequate service is not a pejorative term, and in no way does our use of it imply acceptance of mediocrity in the utility's service offering. Given the state of maturity of the public utility industry, adequate service connotes a well-managed and sophisticated firm continuously meeting and exceeding public demand for the firm's output. In addition, we assume that a utility which provides adequate service is in compliance with laws, regulations, and public policies that govern public utility facilities and operations.

In carrying out this statutory charge, we assess whether PG&E has justified its revenue increase proposals, disallow those proposals to the extent that they have not been justified, and order reductions in the revenues collected by PG&E if the evidence shows that is necessary. We do so with the further recognition that, even with electric industry restructuring and the advent of competition, the Legislature has found and declared in Section 330(f) that "[t]he delivery of electricity over transmission and distribution systems is currently regulated, and will continue to be regulated to ensure system safety, reliability, environmental protection, and fair access for all market participants."

The GRC has been one of the primary vehicles by which the Commission carries out its duties. The California Supreme Court has had occasion to describe the GRC approach as follows:

> "In a general rate setting proceeding, the commission determines for a test period the utility expense, the utility rate base, and the rate of return to be allowed. Using those figures, the commission determines the revenue requirement, and then fixes the rate for the consumers to produce sufficient income to meet the revenue requirement. . . . [(] The rates are fixed in the general proceedings on the basis of historical data. Adjustments may be made in that proceeding for anticipated future extraordinary changes. [Citation.] It is obvious revenue, expense, and rate base arrived at on historical data will not remain constant in future years when the rates take effect. The assumption underlying fixing of future rates on historical data is that for future years changes in the revenue, expense, and rate base will vary proportionately so that the utility will receive a fair rate of return.' (California Manufacturers Assn. v. Public Utilities Commission (1979) 24 Cal.3d 251, 256-257 [155 Cal. Rptr. 664, 595 P.2d 98].)" (City and County of San Francisco v. Public Utilities Commission (1985) 39 Cal.3d 523, 531 [217 Cal. Rptr. 43, 703 P.2d 381].)"

GRCs have evolved since the Court made this observation in 1979 and again in 1985. For example, in 1989, D.89-01-041 transferred the determination of the rate of return for energy utilities to an annual cost of capital proceeding. Also, to some extent, performance based ratemaking orders (PBR) have supplanted the traditional GRC as a regulatory technique for ensuring adequate utility service at reasonable rates. In addition, California's gas and electric industries have been undergoing significant restructuring and will continue to do so, thereby changing the very nature of the utility firm being reviewed. Still, despite these developments, and the interjection of competitive issues into this GRC, our undertaking in this decision is in large part that of a traditional GRC review, with the focus on the utility's distribution functions. As in any GRC, our primary task is to forecast PG&E's revenue requirements for the test period, i.e., the just and reasonable amount of revenues needed by PG&E to provide adequate public utility service and earn a reasonable rate of return for 1999.

We accomplish this task by reviewing how PG&E compares to other utilities in terms of costs and efficiency performance (Section 5), and by reviewing PG&E's and the parties' test year expense and capital forecasts on a department-by-department and account-by-account basis (Sections 7 through 9). Before proceeding to these detailed reviews, we address in the policy and legal issues that shape the approach to this GRC.

4.2.2 Burden of Proof and Evidentiary Standard

The relative advantage of utilities in ratemaking litigation has long been recognized. One writer observed the following 73 years ago:

> "Successful regulation of great public utility corporations, with their properties and their services ramifying in every direction, with vast revenues flowing in continuously, with nationwide alliances, and clearing-houses of technical information and expert service, is no simple and easy matter. The utilities stand ready at all times to save the Commission from exerting itself. They stand ready to produce all the facts which they themselves declare to be pertinent and to explain them to the Commission, and to tell the Commission what its duty is. But the more there is of this, the more the Commission needs time, and money, and experience to do its own investigating, and get to the bottom of things. Very few states appropriate enough funds to enable the Commissions to do their work independently. The only way for a Commission to act quickly is to do what the companies tell it to do, and often the consumers as well as the utilities are impatient of delay.
>
> "If the Commission depends upon the consumers or the municipalities to present the public side of the controversy, the evidence in most cases will be heavily one-sided. <u>A group of consumers, or an individual municipality -- perhaps a small one -- or a loosely associated group of municipalities, working from the</u>

> outside with no funds except what 'they dig out of their jeans' with no hope of ever getting it back, are pitted against the companies having all the inside experience and knowledge, and able to tap the consumers' till with confidence that whatever they spend to defeat the consumers will be added to the cost of service and taxed back in the rates which the consumers themselves will have to pay. If the municipalities or the consumers spend a dollar of their own money, the utility will spend two and make them pay in the bargain. Financial resources, experience, inside knowledge, expert affiliations, great things at stake and continuity of interest, combine to give the utilities an overwhelming advantage in the presentation of their cases before Commission and Courts." (Dr. Delos F. Wilcox, Journal of Land and Public Utility Economics, July, 1926; as quoted in California Railroad Commission, pamphlet by Commissioner Ray C. Wakefield, January 15, 1941, pp. 12-13, emphasis added.)

The problems identified by Dr. Wilcox – utility control through "inside" information and ratepayer funding of their efforts to "defeat the consumers" – have not vanished, although clearly the situation for California ratepayers in 1999 is better than the one he was describing in 1926.[6]

Pursuant to Section 309.5, consumer interests are now represented by Commission staff dedicated to the goal of the lowest possible rates consistent with safe and reliable service. Consumer interests are also represented by effective consumer organizations which are experienced in the complexities of utility regulation and which, in some cases, are supported in part by a statutory

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[6] Indeed, Commissioner Wakefield observed that the situation for California ratepayers was better in 1941 than the scenario painted by Wilcox:

"This situation can be and I am firmly convinced is overcome in California and in the other States having Commissions adequately financed and free enough from politics that a staff of trained men can be developed and retained. Such a staff can obtain the knowledge of the utilities which their own experts have. With such a staff utilities can be regulated, and in California they are regulated." (*Id.*)

plan of compensation of intervenors who contribute substantially to Commission’s decisions. Still, even today, it is our experience that in comparison to other parties, utilities typically are better able, and have the greater incentive, to muster a large arsenal of resources to support their proposals.

While we concur in part with Commissioner Wakefield that Commission staff can obtain the knowledge of the utilities which their own experts have, we recognize that in considering the company’s operations and funding needs, we depend in no small way upon information provided by the company’s own experts. However, this does not mean that we accept uncritically claims such as that of PG&E’s electric distribution capital expenditures witness, who testified that “[g]enerally, 10 years of utility distribution engineering experience is needed to understand and evaluate electric distribution capital investments.” (Exhibit 28, p. 3-2.) In fact, we believe that qualified outside experts can and do provide us with credible information, and must be relied upon to help us assess PG&E’s claims, even though they may lack such detailed knowledge and experience. To avoid the scenario painted by Wilcox, we should not rely solely on the information provided to the Commission by company insiders. Accordingly, we give weight to the testimony of qualified experts who address PG&E’s vegetation management activities. Similarly, we give weight to the testimony of witnesses who address the reasonableness of PG&E’s CIS investments.

The natural litigation advantage enjoyed by utilities, and the fact that we must rely in significant part on their experts, combine to reinforce the importance of placing the burden of proof in ratemaking applications on the applicant utilities. PG&E acknowledges that proposition, although it disputes ORA’s contention that it is PG&E’s duty to support its application through clear and convincing evidence, i.e., “proof by evidence that is clear, explicit and unequivocal; that is so clear as to leave no substantial doubt; or that is sufficiently strong to demand the unhesitating assent of every reasonable mind.” (Jefferson, *California Evidence Benchbook*, (2d ed. 1990 supp.) Section 45.1, p. 602.) PG&E claims that the clear and convincing standard applies only in after-the-fact reasonableness review proceedings, not in test-year ratemaking proceedings. As an initial statement of the law we resolve this dispute in favor of ORA’s position.

First, we note that the Commission has declined to draw a distinction between types of ratemaking cases with respect to the utility's burden of proof:

> “The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs.[7] Whenever the utility comes before this Commission seeking affirmative rate relief, it fully exposes its operations to our scrutiny and review. It may justify the reasonableness of its request and its operations by making at least a prima facie case of reasonableness, even in the absence of opposition. Where it faces opposition, its reasonableness showing is naturally a more difficult undertaking.” (D.87-12-067, 27 CPUC2d 1, 21.)

D.90642, the decision which the Commission cited in the quoted footnote, resolved a general rate increase proceeding of The Pacific Telephone and Telegraph Company. The importance of this issue of the utility's required showing warrants repeating the Commission's discussion here:

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[7] In a footnote at this point, the Commission stated in D.87-12-067 that "[t]he longstanding and proper rule is set forth in D.90642 at 2 CPUC 89, 98-99 and requires that the utility meet its burden by clear and convincing evidence. To meet this burden we have specified that '. . .the applicant must produce evidence having the greatest probative force.'" (D.87-12-067, 27 CPUC2d 1, 169.)

"The staff sets forth the long-standing and proper rule. It is settled that in order to raise rates it is incumbent on the utility to justify the increase before the Commission. (*Northern Cal. Power Company* (1912) 1 CRC 315.) The utility seeking an increase in rates has the burden of showing by clear and convincing evidence that it is entitled to such increase. The presumption is that the existing rates are reasonable and lawful. Any doubts must be resolved against the party upon whom rests the burden of proof. (*Southern Counties Gas Company* (1952) 51 CPUC 533; *Citizens Utilities Company* (1953) 52 CPUC 637; *Park Water Company* (1955) 54 CPUC 498.)

"This Commission is charged with the responsibility of ensuring that all charges, demanded or received by any public utility, shall be just and reasonable. (Pub. Util. Code § 451.) No public utility shall raise any rate except upon a showing before the Commission and a finding by the Commission that such increase is justified. (Pub. Util. Code § 454.) (See City of Los Angeles v Public Utilities Commission (1975) 15 Cal 3d 680.)

"To meet the burden of presenting clear and convincing evidence of the need for an increase, the applicant must produce evidence having the greatest probative force. (*Railroad Commission v Pacific Gas & Electric Company* (1938) 302 US 388.) The credibility of witnesses and the probative value of their testimony are questions for the trier of fact. (*Leonard v Watsonville Community Hospital* (1956) 47 Cal 2d 509, 518.) It is for the Commission to arrive at its findings from the consideration of conflicting evidence and undisputed evidence from which conflicting inferences may reasonably be drawn. (*Southern Pacific Company v Public Utilities Commission* (1953) 41 Cal 2d 354, 362, appeal dismissed, 348 US 919, 98 L ed 414.)

"The Commission may form its own conclusions as to the probative value of the evidence before it. (*Market Street Railway v Railroad Commission* (1945) 324 US 548, 89 L ed 1171.) The Commission may choose its own criteria or method of arriving at its decision, even if irregular, providing unreasonableness is not clearly established. (*Pacific Telephone & Telegraph v Public Utilities Commission* (1965) 62 Cal 2d 634; *American Toll Bridge Company v Railroad Commission* (1939) 307 US 486; 83 L ed 1414.) When the utility has not sustained

> the burden of satisfying the Commission that the proposed increase in rates is justified, the application will be denied (*E. L. Anderson* (1930) 34 CRC 676.)
>
> "The foregoing are the precepts which we must employ in considering the record before us." (D.90642, 2 CPUC2d 89, 98-99.)

These precepts are fully applicable in this GRC, although their application to any specific issue will have to be the product of analysis.

In its opening brief, PG&E notes that effective January 1, 1999, Section 1757 establishes a standard for judicial review in certain Commission proceedings, including ratemaking proceedings addressed to particular parties. (Stats. 1998, Ch. 886.) Section 1757 (a)(4) provides that the court's review includes the question of whether the Commission's findings in a decision are supported by substantial evidence in light of the whole record. After analyzing the law on substantial evidence, PG&E concludes as follows:

> "In summary, it is clear that in light of SB 779, the Commission in this general rate case must be diligent and comprehensive in its examination of the whole record and its weighing of all the evidence. The Commission no longer should expect that its reference to 'any evidence' will be sufficient to immunize it from judicial review by a Supreme Court arguably reticent about second-guessing the Commission on complex ratemaking principles and huge administrative records. Instead, the expanded principles of judicial review enacted by SB 779 will put an increased premium on the ability of the Commission to separate the 'wheat from the chaff' in complex cases such as this, and then to explain and evaluate, in understandable terms and on paper, how it has arrived at its decision on the major disputed issues in the case." (PG&E Opening Brief, pp. 483-484.)

We do not take issue with PG&E's summary of the substantial evidence standard or its implications. The heft of this decision, and the detailed summarization and weighing of evidence it contains, should confirm that. More important, we note that PG&E does not contend that the new substantial evidence standard for reviewing courts changes its obligation as applicant to sustain its burden of proof with respect to its proposals before us.

4.3 Magnitude of the Proposed Revenue Increases

PG&E has claimed that it is seeking revenue requirement increases of $445 million for the Electric Department and $377 million for the Gas Department. These increases are 20.4% and 46.3%, respectively, above what PG&E has shown as its present GRC revenues. We recognize that PG&E did not receive attrition increases for 1997 and 1998, but the proposed increases are still significant by any measure, and are particularly so against the backdrop of relatively low inflation and interest rates in the last several years.

In fact PG&E's proposed electric revenue increase is even greater than indicated above. This is because PG&E included the Section 368(e) safety and reliability funding authorized for 1997 and 1998 in the present GRC revenue of $2,184.7 million, but (appropriately) excluded the funding from the proposed 1999 GRC revenue of $2,629.4 million. Since the safety and reliability increases expired at the end of 1998, and Section 368(e)(1) precludes any presumption in this GRC that "the level of base revenue reflecting those increases constitute[s] the appropriate starting point for subsequent revenues," the accurate and appropriate comparison of proposed to present GRC revenues is made by removing the temporary legislatively-mandated increases from the present revenue figure.

Pursuant to Section 368(e), PG&E received authorized increases of $164.2 million for 1997 (D.96-12-077) and $86.1 million for 1998 (Resolution E-3516). These increases are cumulative. The total increase of $250.3 million includes amounts for transmission and distribution systems.

PG&E states that the Section 368(e) funds embedded in the present GRC revenue of $2,184.7 million is $241 million. The following table shows the amount of Electric Department revenue increase being requested by PG&E, both as presented by PG&E and with the now-expired increases for 1997 and 1998 properly excluded.

Proposed Electric Department Revenue Increase

GRC Revenue - Electric	Including Section 368(e) Increases ($millions)	Excluding Section 368(e) Increases ($millions)
1999 Proposed	2,629.4	2,629.4
Present	2,184.7	1,943.7
Increase Amount	444.7	685.7
Increase Percent	20.4%	33.3%

Thus, PG&E is actually seeking an increase of nearly $686 million (35.3%) for the Electric Department. Even when PG&E's request to withdraw an estimated $37.6 million in revenue requirements for restructuring implementation costs is reflected (see Section 12.1), PG&E's request represents a 33.3% increase. In combination with the proposed gas increase of $377 million (46.3%), PG&E is seeking authorization to collect and retain additional revenues of more than $1 billion in this GRC.

PG&E acknowledges that its proposed revenue increases are sizable. However, PG&E also asserts that the increases are larger than they otherwise would be if the Commission had allowed a larger revenue requirement in the 1996 test year GRC or if it had received attrition allowances for 1997 and 1998. This assertion is true, but on its face is little more than a tautology. It ignores the fact that the revenues authorized for the 1996 GRC were just and reasonable at the time, based on the record of that proceeding.

Further addressing the magnitude of its proposed revenue increases, PG&E argues that:

> "How the revenue requirement increase is characterized is *irrelevant* to the Commission's decision in this case. The Commission must authorize *total* base revenues for the electric and gas departments, which the record supports." (PG&E Reply Brief, p. 7.)

We concur with PG&E's second point. As we have already stated, our primary task in this GRC is to forecast the total amount of revenues reasonably needed by PG&E to provide adequate public utility distribution service in the test period. Our primary policy task is achieve a revenue requirement that is substantively fair and perceived to be fair. The size of the proposed revenue increase is indeed germane to both our forecasting task and our policy task. The fact that PG&E is requesting increases of more than 33% and 46%, respectively above the base electric and gas revenue amounts adopted just three years ago represents a cautionary flag to carefully scrutinize each aspect of PG&E's showing in this GRC. Whether the proposed increases are "extreme," "inflated," or, more to the point, unjustified, is the subject of the remainder of this decision.

4.4 The Need to Develop Fair Revenue Requirements

As we undertake our detailed review in this GRC, we bear in mind the following considerations that both heighten and reinforce the traditional balance between our desire to minimize the allowed revenue requirements to the extent consistent with the law, while achieving an appropriate level of customer service.

4.4.1 Balancing Price and Service Quality

A major premise of PG&E's application is that substantial increases in its authorized revenue requirements are necessary for it to be able to continue providing safe and reliable service. PG&E recognizes that it could pursue a policy of becoming the least-cost provider among its peers, or that it could seek to provide the best possible quality of utility distribution service regardless of price. As PG&E acknowledges, the statutory framework underlying this GRC requires that an appropriate balance of price and quality be struck. While our focus in this GRC is on the funding of PG&E's distribution operations, we must simultaneously consider the overall quality of service, including safety, reliability, and customer service, that PG&E should be expected to provide.

As a starting point, we note that in directing utilities to offer "...such adequate, efficient, just, and reasonable service ... as [is] necessary to promote the safety, health, comfort and convenience of its patrons, employees and the public..." Section 451 does not require that ratepayers pay for the best service possible from a technological standpoint. We do not intend to set revenues at a level to provide funding for what some parties have called "gold-plated" service. We also do not intend to risk degradation of the integrated utility distribution system, and the levels of basic service and reliability which it provides.

PG&E's principal policy witness testified that rising expectations of customers and the Commission for system reliability contributed to the company's request in this GRC. He testified, for example, that increased funding for inspection and maintenance activities is needed to provide the higher reliability desired by customers. In addition to anecdotal evidence of such expectations obtained by PG&E through direct customer contacts, PG&E has conducted more formal surveys of its customers on reliability issues. One such survey shows that residential customers reduced their rating of PG&E's reliability since the beginning of 1994. Specifically, the number of surveyed customers rating PG&E as very good or excellent on several reliability issues declined from nearly 80% in 1994 to below 65% in 1997. This decline occurred while PG&E's electric system reliability as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) remained relatively constant, leading PG&E to conclude that customers are demanding greater reliability. PG&E's surveys revealed that customers placed a higher importance on uninterrupted electric service after the storms of 1995, when millions of customers experienced outages.

A missing piece of PG&E's analysis of its customers' service expectations is an assessment of their willingness to pay for desirable improvements in reliability in or other aspects of service, or their acceptance of the risk of system degradation if infrastructure expenditures they are pay for are cut too close to the bone. There is evidence that most customers prefer improved reliability, but for some customers that preference persists only when cost is not a factor. A survey of California residential, commercial and industrial electric customers, conducted on behalf of the California Energy Commission in the wake of the August 1996 Western States Power Outage, revealed that even though reliable, uninterrupted electric service is very important to most electric customers, some customers are not willing to pay higher rates for such service. Only 21.7% of residential customers, 32% of commercial customers, and 21% of industrial customers stated a willingness to pay higher rates for improved reliability. A complete analysis of the reasonableness of expenditures to improve the integrated utility system would include an assessment of how the cost of alternatives is weighed against the expenditures for utility system infrastructure. Value-of-service analysis is the recognized tool by which such weighing takes place. No party offered such an analysis in this case.

The record shows that customers for whom high levels of reliability is important may have alternatives to obtaining higher reliability from the utility system, such as battery backups, emergency generators, and Uninterruptible

Power Supplies. PG&E emphasized the importance of reliable service to electronics firms and other high technology customers, but as AECA witness Moss testified, these customers may be able to enhance their distribution reliability with approaches that are less expensive than large utility system investments. Moreover, according to Moss, reliability may be one of the few areas in which energy service providers can compete with PG&E during the transition period. Further, Moss explains, it may be more appropriate for PG&E to develop specially tariffed services for these customers that fulfill their needs while avoiding across-the-board systems improvements that result in reliability levels that many customers may be reluctant to fund. We do not endorse any of these suggestions, which may be the subject of further consideration in future proceedings. We do not endorse the implication in these suggestions that the level of the public's basic service should be stratified on the basis of ability to pay, or that we should forego the benefits of integration and economies of scale that system-level investments offer.

ORA and other parties question the need for PG&E to increase reliability and customers rates. PG&E's principal policy witness acknowledged that PG&E should not provide more reliability than the level customers are willing to pay for, however that may be determined. He also offered clarification that in this GRC, PG&E is trying to maintain the current level of service and reliability and is not attempting to accomplish major improvements. We concur with PG&E's clarified policy. Given the absence of adequate value-of-service studies or any other evidence demonstrating that ratepayers not only prefer, but are willing to pay for, improved reliability and other service improvements, we cannot conclude from this record that rising customer expectations justify significant incremental expenditures for achieving major improvements. Nor can we conclude from this record that customers are willing to risk degradation of their service to save a few pennies. Requiring ratepayers to pay for more reliability than they are willing to pay for may be economically inefficient, and, for those customers who do demand high reliability, may thwart the development of optimal solutions for reliability. As we examine PG&E's specific and detailed funding requests, we bear in mind that it should be provided with the levels of revenue necessary to maintain the levels of service it has achieved in recent years while complying with applicable regulatory requirements. We view this as consistent with our commitment, expressed in D.96-09-045 (mimeo., p. 10), to preserve reliability at levels that we have previously accepted as reasonable.

In taking a status quo approach to service quality, we wish to make clear that we are not suggesting that there should be any reductions in reliability or in the overall quality of service provided by PG&E. We take seriously our charge under the Public Utilities Act to ensure that PG&E provides adequate service. We note that in AB 1890, the Legislature reinforced the importance of reliability as restructuring of the electric services industry unfolds. For example, Section 330(g) declared reliable electric service to be "of utmost importance to the safety, health, and welfare of the state's citizenry and economy," and Section 368(e) provided significant incremental funding to PG&E for the express purpose of enhancing transmission and distribution safety and reliability. As we stated in D.98-07-097 (mimeo., at p. 1), we are engaged in "ongoing efforts to develop and refine standards to promote the safety and reliability of the state's electric utility distribution system."

In deciding the last GRC for PG&E, the Commission observed that during the public participation hearings for that proceeding:

> "Speakers raised concerns about high rates, but most emphasized concerns about service quality generally, PG&E's response to the 1995 rainstorms, and cut-backs in utility employees. Some asserted

> that PG&E employees exhibit indifference and a lack of knowledge and training. Rural customers expressed concern about what they perceived to be their low priority status on PG&E's system and asked the Commission to consider their unique safety needs. Some speakers perceive a reduced commitment to system maintenance and raised concerns about whether the PG&E billing system could adequately process a late payment charge." (D.95-12-055, 63 CPUC2d 570, 583.)

We did not hear similar concerns about PG&E's service in the public participation hearings for this GRC. This lends support to evidence indicating that for the most part, PG&E has been providing adequate service in the past three years, at the levels of revenue authorized by us and by the Legislature during that period.

PG&E has stated that if ORA's revenue recommendations in this GRC are adopted, or if equivalent recommendations of other parties are adopted, its customer service will decline and customers will experience more frequent and longer outages. PG&E states that this is because it plans to live within whatever spending levels we authorize for 1999. In view of PG&E's stated intentions, we wish to state again, clearly and emphatically, our policy that any significant degradation in PG&E's service quality is unacceptable. Our intention in this GRC is to authorize revenues which are sufficient to cover the costs of providing adequate service, i.e., continuing level of service achieved by PG&E in the past three years. If we authorize spending on the order of magnitude of ORA's or any other parties' recommendation, we do so with the full expectation and understanding that the authorized revenues are sufficient to maintain adequate service.

We believe that PG&E and its customers are better off if there are clear standards to guide expectations about service. There is an ample basis in the record of this proceeding to adopt service quality measures and procedures for enforcing them. Standards relating to such issues as service request response, billing accuracy and timeliness, participation in Commission-authorized low-income programs are adopted in this proceeding. Other recognized standards relating to system performance (outage frequency, outage duration, outage response) are addressed in the pending PBR proceeding, and should be expeditiously adopted there.

4.4.2 Public Expectations for Electric Rate Reductions

There can be no doubt that one of the principal objectives for industry restructuring and the development of a more competitive market is a reduction in the price of electricity in California. In our industry restructuring decision, we observed that "[o]ur debates have revealed the broadest consensus that our rates are too high and must be brought into alignment with regional averages if California is to sustain a competitive posture as we enter the twenty-first century." (D.95-12-063, 64 CPUC2d 1, 23, as Modified by D.96-01-009, 64 CPUC2d 228.)

In AB 1890, the Legislature found and declared its intent that a cumulative rate reduction for residential and small commercial customers of at least 20% below the rates in effect on June 10, 1996 be achieved not later than April 1, 2002. (Section 330(a).) The Legislature has also found and declared that "reductions in the price of electricity would significantly benefit the economy of the state and its residents." (Section 330(b).) The evidence in this case shows that some market participants estimate the end of the rate freeze could result in electric rate reductions of as much as 40%.

We note from our review of the public participation record in this GRC that there is a common expectation among customers that electric industry restructuring should lead to reduced electric rates for PG&E.

PG&E's proposed increase in electric distribution revenues would offset and therefore delay transition cost recovery, possibly until the end of the statutory transition period. As a matter of policy, we believe that we should guard against approving an excessive base revenue requirement for electric distribution service that would unnecessarily diminish and delay the anticipated rate reduction benefit of restructuring. We have already determined that it is in the interest of ratepayers (as well as shareholders) that the greatest amount of revenues be available for the collection of transition costs. (D.97-06-060, mimeo., pp. 37-38, Findings of Fact 7 and 8, p. 83.) This requires minimizing the authorized distribution revenue requirement to the extent possible, consistent with our other regulatory obligations.

4.4.3 Gas Bill Impacts

PG&E's proposal for gas revenue requirements would have an immediate and substantial impact on gas rates. (Its original proposal called for an average 25% increase in bundled gas rates.) In revenue allocation and rate design proceedings, we seek to avoid or minimize significant bill impacts for the various classes of ratepayers. Just as we have responded to concerns about the impacts of revenue allocation and rate design modifications, we prefer to avoid or minimize major bill impacts from any revenue requirements increases in this GRC. From the public participation record, we are keenly aware that gas bill increases of the magnitude of those proposed by PG&E would cause hardships for many residential and commercial ratepayers. We intend to be mindful of their concern.

With the enactment of AB 1421 (Stats. 1999, ch. 909) the legislature has begun to clarify its expectations about the scope of basic gas service provided by incumbent utilities. Although this legislation was not in effect during the test year, we will not ignore its implications for PG&E's gas distribution operations, particularly in the area of "after-meter services." (C.f., Pub. Util. Code Sections 328, 328.1 and 328.2, added by AB 1421.)

4.4.4 Potential Economic Impacts

ORA's policy witness testified that PG&E's proposals would have a major effect on the small and medium-sized businesses that led the recovery of the California economy from the last recession and that have provided job growth over the last few years. ORA is concerned that PG&E's proposed increases would jeopardize the economic recovery. PG&E's principal policy witness testified in rebuttal that the average 1999 energy bill for small commercial customers taking both gas and electric service will be lower than in 1997 due to the mandatory 10% electric rate reduction now in place.

In this GRC, PG&E is seeking to collect and retain an additional $1.1 billion per year from its electric and gas distribution customers throughout northern and central California. The record in this proceeding does not support specific and detailed findings on the macroeconomic impacts of such increases, and we are not prepared to conclude that adoption of PG&E's proposals would seriously jeopardize the the California economy. Nevertheless, it is clear from generally accepted economic theory that we should not allow PG&E to collect and retain any more revenue than is necessary for it to provide safe and reliable service, and earn a reasonable rate of return on investments needed to provide that service. Doing so would lead to a loss in economic efficiency, and therefore reduce overall economic welfare. This is confirmed by the Legislative finding in Section 330(b), noted earlier, that price reductions would significantly benefit the state's economy.

The suggestion by PG&E that the economic impact of PG&E's proposed increases for gas rates is mitigated by the electric rate freeze and 10% rate reduction for residential and small commercial electric customers is unpersuasive. It has no application for gas-only customers. We are confident that the Legislature did not enact mandatory electric rate reductions so that combined gas and electric utilities like PG&E could mask increases in their gas rates.

On the other hand, we are concerned to avoid erosion of the quality of PG&E's distribution service comparable to what occurred in the early 1990's, that was the subject of D.96-09-045. Substandard distribution service, or an inability to meet expectations about improving gas and electric distribution service can also have a negative impact on California's robust economy.   We will set rates intended fund appropriate levels of service.

There is a related, future ratemaking consideration which we also bear in mind: the intended minimum 20% cumulative rate reduction in Section 330(a). The action we take today will affect our ability and that of PG&E to achieve at least a 20% rate reduction within three years. To the extent that the adopted revenue requirement is excessive, and encourages PG&E to over-build its system and discourages innovation and efficiency, intended future rate reductions could be more difficult to achieve. Of course, we also recognize that to the extent that the adopted revenue requirement is inadequate, and PG&E is discouraged from making needed investments or is encouraged to defer expenditures that will eventually be necessary, it may be equally difficult for PG&E to achieve future rate reductions. This will undermine the credibility of California's electric restructuring process, predicated in part on reduced electric costs for all Californians.

4.5 Future Ratemaking for PG&E

4.5.1 Performance Based Ratemaking

Several parties have pointed out that the revenue requirements adopted in this GRC will serve as the starting point for determining PG&E's revenue requirements under PBR if PG&E's current PBR application or a similar PBR mechanism is adopted. Since PBR is intended as a replacement for GRC ratemaking, and the revenue requirements adopted in this case may affect PG&E's rates farther into the future than would be the case with continued GRCs, they urge us to carefully review PG&E's application with this in mind.

Ideally, a properly-structured PBR mechanism would not have the flaw of being more dependent upon our "getting it right" in this GRC than the alternative of conducting another GRC review in three years. As a practical matter, however, it may not be possible to devise such an ideal PBR. We therefore share the parties' concern regarding the importance of establishing an appropriate starting point for revenues to be established in any PBR mechanism. It echoes our concern in deciding PG&E's last GRC, when we also thought that PBR was imminent for PG&E:

> ". . . [W]e expect that this general rate case may be the last for PG&E. We consider PG&E's revenue requirement with that in mind; that is, we intend to scrutinize all expenses carefully and with an eye toward cutting those expenses which are not well-documented or supported by PG&E." (D.95-12-055, 63 CPUC2d 570, 585.)

PG&E states that its GRC request includes adequate funding to achieve performance measures that it proposes in its distribution PBR application. PG&E argues that to have a fair opportunity to achieve the performance measures which will apply in a PBR regulatory setting, it needs the level of funding proposed in this GRC. We adopt specific safety and customer service standards in this proceeding, and intend to provide adequate revenues to assure that they are met by prudent and efficient managers. However, given the history of divergence between authorized revenues and actual expenditures in mission-critical areas outlined elsewhere in this decision, we will require enhanced levels of monitoring and reporting between the effective date of this decision and the 2002 GRC to be filed pursuant to this decision, to assure that we have “gotten it right” before authorizing the withdrawal of Commission scrutiny and reducing the monopoly cost transparency represented by PBR.

ORA and other parties opposing PG&E’s revenue proposals assert that PG&E’s actions in connection with this GRC are consistent with the “super Averch-Johnson (A-J) effect,” described as follows:

> “It has long been argued that public utilities subject to rate of return type regulation have an incentive to engage in ‘gold-plating’ of their assets, [footnote omitted] and in fact the [Federal Communications Commission] in adopting price cap regulation did so in part to reverse this so-called ‘A-J effect.’ [footnote omitted] Significantly, when a utility is faced with the impending termination of rate of return regulation, it confronts what might best be described as a ‘super A-J effect,’ because it not only has the traditional incentive to overcapitalize, but now has to ‘beat the clock’ to get as much spending done while it still has the ability to recover those costs from captive customers under rate of return regulation.” (ORA / Selwyn, Ex. 86, p. 38.)

The possibilities that PBR will replace traditional rate regulation and that portions of PG&E’s distribution business may become subject to competition constitute requisite conditions for the “super A-J effect“ to occur. We find it to be a credible theory for explaining the type of incentives facing PG&E, and a possible and even likely partial explanation for the increased spending that forms the basis of its request in this GRC. As relevant to this GRC, it is yet another sign for us to be particularly wary of indications of overcapitalization and overspending during the periods that form the basis for PG&E's 1999 forecast.

4.5.2 Attrition Allowances and Reporting

PG&E has requested an attrition allowance for Attrition Years 2000 and 2001. For Attrition Year 2000, the amount request is $148 million. For Attrition Year 2001, the amount requested is $121 million. These amounts are predicated on changes in activity levels, capital investment, escalation of labor cost and escalation of nonlabor cost. Subject to reporting requirements concerning expenditures for reliability, new business and service upgrades, and subject to the results of the Commission's annual cost of capital proceedings for the Years 2000 and 2001, we will grant an attrition adjustment for Attrition Year 2001 because we find the forecasted activity levels, labor cost escalations and capital investment forecast reasonable. As forecasted, this represents an increase in authorized distribution revenues of 5% in Attrition Year 2001, predicated on PG&E's filing an application.

The current authorized return on equity is 10.6%. Authorized return on rate base is 8.75%. We will not approve a revenue mechanism as part of PG&E's PBR, preferring to develop a more precise base level for distribution costs. According to the timing established by the Rate Case Plan, PG&E should file an application for the attrition allowances authorized here to provide a vehicle for enabling us to determine whether the additional costs we have authorized in this decision, in fact, reflect PG&E's normal operation. The attrition allowance application should be accompanied by reports documenting maintenance expenditures, including vegetation management as agreed to by PG&E in its settlement of the Rough-andReady Fire investigation, I.98-07-009, pipeline safety and replacement, reliability related maintenance and capital, new business activity and related investment, as well as operation and maintenance expenditures related to distribution customer service activities. These reports are intended to assure us and the public that authorized revenues are being expended for the purposes intended, and that actual earnings reflect authorized returns.

4.5.3 Supervision of Accounting Procedures related to Rate Proceedings

In 1996, PG&E implemented a significant change in its internal management protocols, the SAP system. A number of the factual disputes in this case resulted from reclassification of expenditures from one account under the Uniform System of Accounts to another, or the recharacterization of expenditures from O&M to capital or vice versa. It is clear from the record that our staff had no opportunity to work with PG&E in the development or implemention of the SAP system, and therefore, was unprepared to evaluate the fairness of the financial, operational and accounting presentation that PG&E made in this case. ORA spent significant sums of ratepayer dollars on outside consultants, some of whose time was taken up with the evaluation of the SAP system and the underlying transactions. In at least one case, the ALJ who heard the evidence in this proceeding considered that a SAP-related reclassification resulted in the presentation of knowingly false information, with the result that ratepayers were double billed over a period of several years. The ALJ in this proceeding recommended that we initiate an investigation to determine whether PG&E violated Rule 1 of our Rules of Practice and Procedures by this behavior. Rule 1 provides sanctions against parties who present knowingly false information to the Commission. As discussed below, we do not act on this suggestion, but note the source of the problem.

At all time pertinent to this proceeding Public Utilities Code Section 1823 was in effect and applicable to the Commission and PG&E. This statute provides:

> 1823. The commission shall periodically review and monitor the development and use of any operations model used by any public utility. The commission or any party may use the output of these operations models as evidence in a proceeding or hearing, withoutintroducing into evidence the full methodology used to generate this output, if the commission has monitored that operations model continuously for at least 12 months before the hearing or proceeding and has reviewed and verified the operations model for accuracy no more than three months before the hearing or proceeding. However, no party shall be prohibited from reasonably cross-examining any witness who introduces this evidence.

The term "operations model" is defined by Section 1821(b) as follows:

> (b) "Operations model" means a computer model that replicates, lists, describes, or forecasts a public utility's internal functions, including, but not limited to, its accounting procedures, cash management procedures, personnel assignments and procedures, and inventory control.

Had the Commission and PG&E observed the provisions of this statute, as intended by the Legislature, the effort and acrimony associated with the disputes over characterization and presentation of basic financial data in this proceeding could have been avoided. We will not act on the ALJ's recommendation that a Rule 1 investigation be initiated, because to do so would perpetuate the atmosphere of strife and mistrust that we are seeking to move beyond. However, we expect that our Energy Division will thoroughly review the SAP system with PG&E so as to understand its procedures for assigning transactions to particular accounts, and we expect PG&E to cooperate fully with our staff in making these matters transparent as they relate to the provision of utility distribution service, both gas and electric. The results of this review should be presented in a joint report by PG&E and Energy Division staff filed in the first attrition allowance application, and periodically updated thereafter.

Section 1823 was repealed by Assembly Bill 1658 (Rod Wright), Stats. 1999, Chapter 810, effective January 1, 2000. This bill was a technical cleanup bill, purporting to eliminate unnecesary or obsolete statutory provisions. It specifically provides that no power or authority of the Commission is diminished in any way by the elimination of the obsolete provisions. The Commission may execise any such power and authority under its general necessary and proper provision, Public Utilities Code 701.

4.6 The Transition to Competition

There is evidence in this record that the electric rate freeze for PG&E could possibly end before the statutory termination period. Several parties believe that by increasing base revenues through this GRC and using up "headroom," PG&E is attempting not only to maximize the revenues collected from electric distribution customers, but also to forestall the onset of competition and at the same time better position itself to compete. This belief is bolstered by the fact that PG&E has a corporate goal of realizing the benefits of AB 1890 by, among other things, ensuring that the electric rate freeze continues through 2001 while also ensuring that stranded costs are recovered in full. We note that the goal was communicated to PG&E officers and managers responsible for this GRC before the NOI was filed.

We do not intend for our decision in this GRC to be an instrument of PG&E corporate policy in the post-transition period. The competitive role of the UDC is being scrutinized in other proceedings before the Commission; our objective in this proceeding must be to assure the financial and operational integrity of distribution infrastructure, currently provided on a monopoly basis by PG&E, without directly or indirectly undermining robust competition in energy markets. We have been careful to limit the extent that authorized activities and associated revenues may impact competitive markets.

As explained previously, we believe that the greatest amount of revenues possible should be available to pay down Commission-authorized transition costs so that the rate reductions which are anticipated upon conclusion of the rate freeze can be realized as soon as possible. Beyond this immediate benefit for customers, development of a more competitive electric services market in California will be possible when the rate freeze is ended and rates can be reduced. Since transition costs may be recovered before the statutory rate freeze period ends, establishing an excessive electric revenue requirement in this GRC, i.e., more than the amount necessary for provision of adequate service could have the effect of unnecessarily delaying the onset of more vigorous competition and could allow PG&E to secure an unfair advantage in the competitive marketplace. This outcome should be avoided. However, we will not use concern for market development to reduce capital and O&M spending below levels that support the provision of adequate service, or compel PG&E management to risk inadequate service in order to respond to their shareholders demands for earnings.

While this is neither a generic nor a utility-specific restructuring policy proceeding, it is not being conducted in a vacuum. We are mindful that we are establishing PG&E’s regulated utility revenue requirement in the midst of the transition to a more competitive industry structure. Thus, the Scoping ACR appropriately provided that determining the reasonable revenue requirement for PG&E’s electric department may require consideration of the extent to which ratepayers ought to recompense a utility for operations that have been opened up for competition by electric restructuring. To the extent necessary for determining the utility revenue requirement for regulated services that PG&E will continue to offer, allocations of costs to competitive and monopoly services are at issue in this proceeding. Enron and ORA have introduced specific proposals to address their concerns regarding PG&E's ability to enhance its competitive position through subsidization of competitive or potentially competitive activities. Enron's proposals for further cost unbundling and ORA's proposal for a Profit Center mechanism to address this concern are addressed later in this opinion.

4.7 PG&E's Work Force

PG&E states that it will reduce its work force by layoffs if ORA's or other opposing parties' funding recommendations in this GRC are adopted. PG&E's senior vice president and general manager of Distribution and Customer Services testified that the difference between the labor expenses included in ORA's and TURN's recommendations and the amounts requested by PG&E represents the wages and salaries of 3,000 distribution and customer service employees. He further testified that ORA's and other parties' management policy and resulting cost recommendations would result in PG&E's having 3,000 fewer full time employees. He later testified that PG&E could reduce its work force by 3,000 maintenance employees and possibly 4,000 or 5,000 employees in total. PG&E states that its plan for work force reductions is not a threat, but is merely a reflection of its policy to live within the spending levels the Commission decides are appropriate. IBEW urges the Commission to accept PG&E's requested staffing levels to ensure improvements in system reliability and customer communications.

PG&E requires a reasonably large force of trained and skilled employees to construct, operate, maintain, repair, improve, and extend facilities throughout its service territory. PG&E's workers attended and participated extensively in each of the public participation hearings, and they made a persuasive case for recognizing the value of their services to ratepayers and the general public. We expect PG&E to be a fair and competitive employer, and we intend that the rates we authorize will reflect that expectation. As a public agency that itself has undergone significant downsizing in recent years, we are keenly aware that downsizing brings disruption to the operations of an organization as well as hardships to affected workers.

Our decision in this case establishes a revenue requirement for PG&E, based on our review of operations, that appears fair to the public and the employees. In the final analysis, the size of PG&E' work force is a matter of PG&E's management discretion. We must draw a distinction between our concern for workers that may be affected by downsizing and our duty under the Public Utilities Act to determine the funds needed by PG&E to provide adequate utility distribution service, including the "comfort and convenience of ... employees."[8] If the revenue amounts that we find to be sufficient for the provision of adequate service lead to a management decision to reduce the number of workers, we are without jurisdiction or authority to change that decision so long as it comports with Section 451.[9]

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8 Public Utilities Code Section 451, third sentence. We have not had occasion to interpret this language in the specific context of a large scale energy utility, but note that it could be the basis for challenging a pure "market" approach to employment issues.

9 In Section 330(u), the Legislature addressed the issue of work force reductions caused by electrical restructuring. It did so by providing a mechanism in Section 375 to fund

Footnote continued on next page

However, we are mindful that past PG&E down-sizing has significantly eroded its ability to maintain its facilities and provide adequate service. We have found this behavior to be unacceptable in the past, and strongly encourage PG&E management to find cost savings, if necessary, in areas where the morale and ability of line employees to provide service are not jeopardized.

4.8 Community Services

We heard repeatedly during the public participation hearings that, in addition to fulfilling its public utility obligations, PG&E contributes to the general welfare of communities throughout its service territory. Groups that benefit from PG&E's community involvement include disaster relief organizations and community and youth development organizations. Many of these organizations urged us to consider PG&E's role as a "corporate citizen" in acting upon this GRC application.

We commend PG&E for the valuable community services it performs. It is clear that organizations and communities throughout PG&E's service territory benefit from PG&E's involvement. Nevertheless, we do not allow funding for this aspect of PG&E's operations to be reflected in the revenue requirements for regulated utility service. We note that PG&E itself has not asserted that the costs associated with these activities should be included in this GRC.

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the reasonable costs of voluntary severance, retraining, early retirement, outplacement, and related benefits. The Legislature has not conferred equivalent, specific authority on the Commission to authorize funding for work force reductions caused by resetting a utility's authorized revenue requirement to the lowest level consistent with the provision of adequate utility service.

4.9 Conclusion - Policy: The Need for Accountability

At the time of its last GRC, PG&E pursued a comprehensive corporate strategy to lower rates in the long term while providing excellent service to customers. (D.95-12-055, 63 CPUC2d 570, 585.) In that GRC, PG&E had portrayed its request as one which reflected exceptional productivity gains and "a transformation of its corporate culture to reduce costs in recognition of changes in energy markets." (*Id.*)

In this GRC, by contrast, PG&E's commitment to service remains but its commitment to cost reduction and lower rates is far less clear. The facts that PG&E's showing began with instructions to field personnel having a "customer-service-at-any-cost mentality" (Tr. V. 14, p. 816) to identify all work that needs to be done; that "many times the estimates that [were brought forward reflected] every bit of work we need to do to provide the ultimate quality of service," (*Id.*); and that such estimates were only then pared back by managers who were aware of PG&E's corporate goal of extending the rate freeze, are consistent with the proposition that PG&E has downgraded or de-emphasized its commitment to cost cutting and rate reduction since its previous GRC. We intend to pusue a policy which balances maintaining reliability and quality of the integrated distribution system with cost discipline and accountability.

We retain a strong commitment to minimizing PG&E's authorized revenue requirements to the extent consistent with provision of adequate service. Accordingly, we will consider whether PG&E's specific funding requests reflect a "wish list" of projects and expenditures, undisciplined by value-of-service or other cost-effectiveness analysis, or reflect expenditures that are clearly needed for the provision of utility distribution service.

We also carefully consider PG&E's forecasting methods. Since PG&E relies in significant part on 1996 actual spending levels, which exceeded 1996 authorized levels by $240 million, we will be particularly watchful for the possibility that one-time expenditures and expenditures which result from past deferred or deficient practices are reflected in PG&E's request. We recognize PG&E's position that, in retrospect, it requested and received inadequate funding in the 1996 GRC. The outages caused by the 1995 storms and the aftermath of those outages undoubtedly provided PG&E with a wake-up call to attend to the basics of providing adequate utility service. We further recognize that PG&E's Electric Department is subject to regulatory standards such as call center performance requirements that did not exist in 1994, when it developed its test year 1996 GRC application. However, as we noted earlier, the 1996 authorized expenditures were adopted as just and reasonable at the time, and the rates based on those expenditures are presumed to be reasonable and lawful until shown to be otherwise. Absent a clear and convincing showing, the mere creation of a new requirement or standard does not alone automatically translate into significant new expenditures to achieve that standard. We note, for example, that standards for the operation, reliability, and safety of electric systems during emergencies and disasters were recently adopted in the absence of any claims that the rules involved significant implementation costs. (D.98-07-097, mimeo., p. 7.) Therefore, for each component of the total revenue requirement forecast that we consider, we will evaluate and give appropriate weight to alternative forecasting techniques presented by other parties, such as trending and multi-year averages.

ORA expresses its concern regarding the use of 1996 actual spending as follows:

> "PG&E notes that by spending significantly more than authorized in 1996 the company's return on equity has been adversely impacted. (PG&E / Randolph, Ex. 2, p. 1-15.) The more pertinent evidence is

> that in eight of the eleven years from 1985 through 1995 PG&E was earning more than the authorized rate of return. (Exs. 60, 61.) During the same time period PG&E was significantly underspending its authorized electric and gas distribution maintenance budget. The fact that the company has placed the system back in a decent state of repair by spending more than the currently authorized amount is no basis for imposing significantly higher costs on ratepayers on a going forward basis under the guise they are demanding greater reliability. Granting PG&E's request would result in future ratepayers paying for PG&E management's poor decisions." (ORA Opening Brief, p. 21.)

Between 1987 and 1994, PG&E underspent the adopted electric maintenance budget by a total of $495 million. Given the high level of concern in this GRC that PG&E has placed too much emphasis on 1996 actual expenditures in constructing its forecasts for 1999, and the concern that PG&E's 1996 spending included activities that had been funded in earlier GRCs but not performed, our discussion in San Diego Gas & Electric Company's (SDG&E's) 1993 GRC is apropos:

> "The purpose of a general rate case is to develop and adopt sound, informed estimates of the reasonable costs to be incurred in the test year. We know that our adopted levels of revenues and expenses may be at variance with actual experience. However, we must be sufficiently informed to know that adopting a given estimate makes sense. Part of this process involves making sure that we do not repeatedly approve revenues to meet a one-time cost. When a utility's expense estimate includes the performance of a task it had planned to accomplish with previously authorized funds, we will want to know why the utility did not spend its funds as planned the first time around and will be hesitant to charge ratepayers twice for the same expense. In addition, we want to be confident that the activities being undertaken by the utility are lawful and otherwise consistent with public policy." (D.92-12-019, 46 CPUC2d 538, 555.)

However, we must insist upon PG&E demonstrating, for each component of its proposed revenue requirements, that it produce clear and convincing evidence.

To the extent it fails to do so, we cannot grant its requested revenue increase. Given that PG&E's Vice President for the GRC wrote an internal communication proclaiming that "there is no way the CPUC will authorize what we have asked for" (Exhibit 68), and given the history of PG&E receiving only a fraction of the total increases it has sought in GRCs over the past 15 years, this cannot be a surprising proposition for PG&E.

Where we do grant significant additional revenues, particularly the areas of vegetation management and capital spending, we intend to put into effect specific procedures to hold PG&E accountable for its expenditures of funds we authorize. These are described in more detail in Chapter 7.

5. Productivity and Cost Studies

The Commission has maintained a practice in GRCs of analyzing improvements in the over-all productivity of applicant utilities, and comparing applicant utilities with benchmarks derived from comparison entities (real or constructed benchmark utilities) as a way of gauging the general effectiveness of management. We intend to continue this practice, while recognizing that the structural dismemberment of the vertically integrated utility involved in California's electric restructuring makes comparison with past studies and with comparison entities increasingly problematic. There is value in knowing how the managers of California utilities stack up against their peers.

However, the ability to game the outcome of the studies leads us to conclude that they are not by themselves reliable indicators of the general reasonableness of costs (or lack thereof), or the prudence and effectiveness of utility managers. The testimony in this proceeding illustrates clearly the basis for our caution.

5.2 Productivity Studies

Pursuant to D.86-12-095, PG&E and ORA presented total factor productivity and multi-factor productivity (MFP) studies of PG&E's electric and natural gas activities to gauge whether productivity growth justifies changes in base revenues. PG&E and ORA both found that PG&E's gas and electric revenue requirement requests in the original application were consistent with, and even below, what was predicted by total factor productivity analysis.

ORA found that over the period 1976 through 1996, PG&E's electric MFP increased by an average of 1.07%, a figure nearly identical to PG&E's 1.02%. For the period 1987 through 1996, PG&E reported an MFP of .27%, and ORA's model yielded a result of .45%. PG&E actually forecasts declining MFP values over the years 1997-1998, with a negative .001% in the test year. ORA's forecast similarly declines, but remains positive in the test year at .23%. Similar differences exist between PG&E's and ORA's estimates for the gas department analysis, but they do not form the basis of any recommended ratemaking adjustments by ORA.

As ORA points out, productivity results were calculated on a bundled basis, and their relevance for forecasting O&M expenses is limited for this proceeding, where utility expenses are no longer considered on a bundled basis.

5.2 Aggregate Cost Comparison Studies

5.2.1 Introduction

In addition to analyses of costs associated with individual accounts and activities, PG&E and ORA presented a total of four studies which examine PG&E's aggregate costs in comparison to those of other utilities.

PG&E states that the purpose of three such studies which it performed was to address the general criticism that its costs are too high. From these studies, both individually and taken together, PG&E draws the conclusion that its 1996 costs were reasonable given the business conditions it faces. PG&E further concludes that it is reasonable to use recent historical costs as the basis for its revenue requirement forecasts in this GRC. PG&E acknowledges that it has relatively high electric rates, but takes the position that the driving factor is not high costs. Instead, according to PG&E, its rates are relatively high because its consumption per customer is relatively low.

ORA takes the position that when properly applied and interpreted, the three cost comparison studies presented by PG&E and an additional analysis which it presented support a finding that PG&E is not particularly efficient compared to its peers. Enron believes that PG&E's unit cost study cannot be relied upon to conclude that PG&E's expenditures are reasonable.

5.2.2 Unit Cost Study

PG&E performed a unit cost study which it characterizes as a simple comparison of 1996 operating costs across a sample consisting of the 100 largest electric utilities in the United States. PG&E determined unit costs by dividing cost data from FERC Form 1 by miles of line or by the number of customers. The study develops unit costs for transmission plant per mile, transmission net plant per mile, transmission O&M per mile, distribution plant per mile, distribution net plant per mile, distribution O&M per mile, customer accounts per customer, customer service per customer, and A&G per customer. PG&E believes that dividing total utility costs for these functions by an appropriate scaling factor such as miles of line allows a direct comparison of unit costs among utilities.

PG&E found that its unit costs in 1996 rank within one standard deviation of the mean of the sample in all nine cost categories studied. PG&E concluded that its 1996 costs were comparable to those of other utilities and therefore reasonable. With respect to customer service expense per customer, an area where PG&E concedes that its costs are relatively high, PG&E notes that its costs are driven in part by the Commission's aggressive Demand-Side Management (DSM) and Customer Energy Efficiency (CEE) programs.

ORA and Enron find several faults with PG&E's unit cost study and PG&E's conclusion that its costs in 1996 were reasonable. ORA believes that by normalizing only for scale, the study is too simplistic to identify "best-in-class" utilities and provide meaningful benchmarking analysis.

ORA suggests that A&G costs should be normalized by output in megawatt-hours (MWh), rather than number of customers. ORA believes that using the number of customers biases the analysis in favor of PG&E because it has the largest number of customers of any utility in the sample. PG&E counters that ORA's approach disadvantages companies such as PG&E that have worked to moderate usage per customer through conservation measures. On the other hand, as ORA points out, there is no evidence that other utilities in the sample have not also worked to moderate customer usage through conservation.

ORA also suggests that transmission plant and transmission O&M should be normalized by coincident peak demand, rather than by miles of line. PG&E counters that this approach ignores conditions such as customer density and topography, and gives no consideration to the locations of the load centers relative to the locations of the generating resources and system interconnections. PG&E notes that its transmission system was and is influenced by the availability of relatively remote hydro generation and the ability to interconnect with neighboring utilities to jointly optimize operating costs. Thus, with respect to transmission costs, PG&E believes that it is disadvantaged by ORA's adjustment.

Enron discovered what it finds to be outlier data for distribution plant-in-service, distribution net plant-in-service, and distribution O&M expense. For example, Enron found that of the 97 utilities measured for distribution plant-in-service per mile of distribution line, 82 had costs at or below $92,000; 95 had costs below $200,000; and the 96th and 97th utilities had costs of $283,925 and $845,609, respectively.[10] For distribution expense per mile of distribution line, all but one utility had costs under $8,700, while the 97th utility had a cost of nearly $47,000.

Enron concludes that when the PG&E's unit cost data for distribution, customer accounts and customer service are analyzed in alternative ways, PG&E's claim that its unit costs are comparable to those of the other sample utilities is called into question. Specifically, where PG&E used mean values, Enron compared PG&E's unit costs with the medians. Enron also compared PG&E's unit costs with the average excluding the highest and lowest single unit cost value and the average excluding the five highest and five lowest unit cost values. The following table, taken from Exhibit 170, shows PG&E's results Columns 1, 2, and 3) as well as Enron's alternative results (Columns 4-9):

10 Although PG&E used a sample of 100 utilities, data for some categories were available for only 97 utilities.

Enron's Alternative Unit Cost Comparisons

	PG&E ($)	Average ($)	PG&E Greater than Average (%)	Median ($)	PG&E Greater than Median (%)	Average-Excluding Highest, Lowest ($)	PG&E Greater than rev. Average (%)	Average Excluding 5 Highest, 5 Lowest ($)	PG&E Greater than rev. Average (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Distribution Plant Per Mile	85,096	76,800	11	60,069	42	69,277	23	64,723	31
Distribution Net Plant Per Mile	50,066	50,398	-1	39,761	26	45,646	10	42,560	18
Distribution O&M Per Mile	3,359	3,054	10	2,262	49	2,616	28	2,480	35
Customer Account Per Customer	49.7	41.4	20	39.0	27	41.1	21	40.6	22
Customer Service Per Customer	23.0	20.6	12	16.8	37	19.5	18	18.5	24

Using mean values, PG&E's analysis shows that its costs range from -1% to 20% of the average utility unit cost for these five functions. However, when compared to the median values, PG&E's unit costs for these functions range from 26% to 49% above the average. When PG&E is compared to the average for these same functions, but the single highest and lowest values are excluded from computation of the mean, PG&E's unit costs are anywhere from 10% to 28% higher than average. When the five highest and five lowest values are excluded from the computation of the mean, PG&E's unit costs place between 18% and 35% for these same functions. Enron believes that these recalculations dispel the claim that the unit cost data support the conclusion that PG&E's 1996 recorded data are reasonable for estimating 1999 test year expenditures.

Discussion

ORA has cast doubt on whether the scaling factors chosen by PG&E yield the most meaningful comparisons, although we recognize that the alternative scaling factors of output for A&G costs and coincident peak demand for transmission have weaknesses as well. In addition, PG&E acknowledges that the unit cost study cannot identify the “best-in-class” company, and that it can only provide a general indication of how its costs compare to those of the utility industry. Accordingly, we concur with the conclusion that PG&E’s unit cost study is, at best, of limited value for assessing PG&E’s performance or the reasonableness of PG&E’s revenue request.

To the extent it can be relied upon for benchmarking, we note that the unit cost study results presented by PG&E for distribution and customer service, even without the adjustments made by ORA and Enron, show PG&E to be a mediocre performer relative to the comparison group of utilities in both these areas. For example, PG&E ranked 76 out of 97 utilities (rank order goes from lowest cost to highest cost) in distribution O&M expense per mile, and 73 out of 100 utilities in customer service and informational expense per customer. We further note that while PG&E asserts that its customer service expenses are high because of our DSM and CEE programs, the utility with the lowest cost in this area operates in a state that has higher DSM costs than California.

PG&E dismisses Enron’s alternative calculations of the mean values as arbitrary exclusions that do not add to the value of the study. We disagree. Enron has shown that removal of just two data points out of nearly 100 significantly changes the results of the analysis, which lends credence to the concern that PG&E’s sample may be significantly affected by outlier data. Along with the concerns about this study that were raised by ORA, we agree that

Enron's alternative analysis undermines PG&E's claims regarding its costs in the areas of distribution and customer service. PG&E's costs may not be as "comparable," i.e., similar, to the average of other utilities as PG&E attempts to portray. This relatively weak cost comparison showing urges moderation and caution when considering a request to increase costs dramatically.

5.2.3 Composite Utility Cost Study

PG&E engaged the Monitor Company to perform a study of normalized costs in the areas of electric transmission, distribution, customer service and A&G costs. This study compares PG&E's recorded 1996 costs to those of a composite utility made up of the 10 largest IOUs in the nation based on total number of customers. The Monitor study normalizes PG&E's costs for differences in cost drivers and scale, and compares the results to the costs of the composite utility. It is designed to reflect what PG&E's costs would be if PG&E operated with the same configuration of cost drivers and scale as the composite utility. As used in this study, cost drivers include such factors as labor market, percent of urban territory, customer density, asset configuration, and service functionality. Scale refers to measures of utility's size, such as line miles, number of customers, size of territory, and number of employees.

PG&E concludes from this study that its aggregate costs are within one percent of the composite's, and are therefore comparable to those of the 10 largest IOUs. PG&E points out that the study did not quantify a number of factors that may affect utility costs, such as weather, degree of unionization, extent and impact of natural disasters, and infrastructure age. PG&E thus asserts that any claim of further precision, beyond the conclusion that its overall costs are comparable, is unjustified.

ORA does not generally take issue with the normalization process that lies at the heart of the Monitor study and that permits comparisons among utilities with varying customer and territory configurations. ORA further acknowledges that PG&E's study may accomplish its limited goal of demonstrating PG&E's overall comparability to the average large utility, at least at the aggregate cost level (the Monitor analysis shows PG&E's normalized costs to be 11%-12% higher than the composite average in the areas of distribution and customer service). ORA does, however, find methodological problems with the analysis. Moreover, ORA takes strong exception to the structural design of the study in which PG&E's performance is benchmarked against that of the composite or average utility performance, without any showing that the cost level of the composite is reasonable or efficient.

ORA criticizes the Monitor study as being results-oriented. ORA points out that in responding to its criticism that the ten largest IOUs do not necessarily reflect the most appropriate peer group for the normalization analysis, since no effort was made to examine the efficiency of the individual companies comprising that peer group, PG&E witness Diffendal testified that the peer group was selected "as the group which offered the most comparable results to PG&E." ORA notes further that when he was asked about the selection of peer groups for benchmarking studies in general, Diffendal acknowledged that the manner in which Monitor picks companies to benchmark is largely driven by the goal of the specific benchmarking study.

An example of what ORA considers to be Monitor's results-oriented methodology is the inclusion of Consolidated Edison (Con Ed) as a member of PG&E's peer group. Con Ed ranked last in all four functional cost areas studied; has normalized expenses for each of the four categories that were at least a standard deviation above the peer group average and were 90% above the rest of the peer firms in the composite utility; and has anomalously high normalized transmission costs due to its having predominantly underground facilities. Excluding Con Ed from the peer group results in PG&E's normalized costs increasing from 1% to 6% above the composite average. PG&E's witness acknowledged that costs on the order of 5% to 10% above the composite average would probably be the threshold for a finding of comparability. ORA believes that exclusion of this one firm would nullify Monitor's finding of PG&E's comparability to the average. ORA concludes that by including Con Ed, Monitor has skewed the average cost performance in PG&E's favor, thereby masking PG&E's inefficiency in comparison to other companies.

To further support its contention that the Monitor study is results-oriented, ORA notes that Monitor used recorded adjusted costs for PG&E but used unadjusted costs for the other utilities. ORA finds this asymmetric treatment to be particularly problematic in the area of A&G costs, where the effect of the adjustments was to reduce PG&E's A&G expenses from $646 million to $482 million. ORA witness Kravtin testified that there is every reason to believe that many of the reductions made to PG&E's costs would be applicable to the other utilities, yet Monitor appears to have made little attempt to research or estimate comparable adjustments for the composite utilities. ORA determined that adjusting the A&G costs of the composite utilities to reflect the types of adjustments made by Monitor to PG&E results in PG&E's normalized costs falling 5% above the composite average as opposed to 1% above as reported by Monitor.

As noted earlier, ORA believes that to evaluate whether PG&E's revenue request is reasonable, PG&E should be compared to efficient or superior performing utilities, not to the composite average. With this purpose in mind, ORA expanded the Monitor analysis by comparing PG&E's normalized costs to the normalized costs of the individual utilities that make up the composite. Then, consistent with benchmarking principles, Kravtin compared PG&E's normalized costs to the normalized costs of utilities exhibiting the best cost performance in each of the four basic functional cost areas. ORA found that PG&E ranked eighth out of the eleven largest IOUs examined in the areas of distribution and customer service, with normalized costs some 30% and 66% higher than those of the best-in-class, respectively. Aggregated across all functional cost areas, PG&E's normalized costs were 35% higher than the best-in-class.

ORA witness Kravtin also used the Monitor study to evaluate PG&E's 1999 GRC request directly, by substituting PG&E's 1999 forecast of 1999 expenses for the 1996 PG&E data used in the analysis. ORA concluded that it was reasonable to do so because (1) the 1999 data presented by PG&E was in 1996 dollars, allowing direct comparison; (2) the Monitor study normalization process is designed to account for scale differences; and (3) the only peer group utility with a rate case pending had initially defended a rate freeze in the face of a recommendation by the Virginia State Corporation Commission staff for a rate reduction then agreed to a reduction, and another peer utility had been ordered by the Texas Public Utility Commission to decrease its rates. ORA concluded from this analysis that PG&E's normalized forecast expenses for 1999 are 7% above the composite average (where its normalized 1996 expenses were shown to be 1% above the composite level).

Discussion

On its face, the Monitor composite utility study shows that PG&E's aggregate costs in 1996 were within 1% of the average of the ten-utility composite. However, as we will explain, and as with PG&E's unit cost study, ORA has raised concerns which tend to cast doubt on the reliability of PG&E's composite utility study. To the extent it can be relied upon, the conclusion that PG&E draws from the study results cannot be supported.

First, we are troubled that the approach to the study may have been more results-oriented than is reasonable or appropriate for a study of this nature and purpose. The author's seeming acknowledgment of this may be telling. In any event, the inclusion of Con Ed in the peer group, with its associated outlier values, strikes us as problematic. Exclusion of this single firm significantly alters the outcome of the analysis, resulting in PG&E's aggregate costs falling at 6% rather than 1% above the composite. As PG&E's witness seems to acknowledge when he states that a range of costs from 5% to 10% above the average is the threshold for a determination of comparability, we cannot conclude that PG&E's costs are similar to the peer group that excludes Con Ed.

Second, we note ORA's concern that PG&E's adjustment of its own costs combined with its failure to make similar adjustments to the other utilities in the peer group appears to skew the average in a way that favors PG&E. We recognize PG&E's rebuttal argument that adjustments were included to address problems created by PG&E's implementation of its new business system during 1996. However, the issue is not these adjustments to PG&E's costs, but the failure to investigate similar adjustments for the other peer utilities.

Taking at face value the results of the Monitor study as presented by PG&E, PG&E is shown to be an average or slightly below average performer relative to the peer group composite. But the fact that PG&E may have been performing nearly as well as this average in 1996 does not by itself demonstrate that PG&E's request in this GRC is reasonable.

PG&E criticizes ORA's expansion of the Monitor study to derive a best-in-class analysis as inappropriate. This is not only because the study did not quantify factors such as weather, degree of unionization, extent and impact of natural disasters, and infrastructure age, but also because PG&E finds fault with the use of FERC Form 1 data for this purpose. PG&E believes that the standards by which utilities allocate costs across cost categories for the purpose of FERC reporting varies widely by utility. According to PG&E, selecting a single data point as the best performer ignores differences in reporting and skews the analysis. Finally, PG&E believes that the analysis performed by ORA emphasizes least-cost, which is not the same as best-in-class performance.

To the extent that PG&E is correct in its criticism of ORA's expansion of the Monitor study, on the grounds that Monitor both failed to incorporate relevant factors and used FERC Form 1 data which is assertedly unreliable, we are forced to question the value of the Monitor study for any purpose in this proceeding, including PG&E's. However, as ORA points out, no study could ever control for all variables, and the failure to do so is not, alone, a sufficient reason to reject the study as presented by PG&E or ORA's use of it. FERC Form 1 was implemented as a uniform system of reporting expenses for utilities, and the resulting data is highly respected and widely used in both regulatory and financial applications. Finally, although PG&E criticizes ORA's best-in-class analysis as a mere determination of the least-cost utility and fails to consider the level of performance, we find the criticism is neutralized by PG&E's own testimony that the Monitor study attempts to adjust for the cost effects of providing different levels of service quality and, more generally, by the very design of the study in which numerous cost drivers are controlled for by normalization.

We find that despite the weaknesses of this study that were noted by both PG&E and ORA, ORA's expansion of the Monitor study tends to offer credible support for the proposition that PG&E was not operating as efficiently as it might have in 1996. The finding that PG&E's normalized, aggregate costs in 1996 were 35% higher than the best-in-class seriously undermines the claim that PG&E is an efficient operator. The best that can be said for PG&E on the basis of the Monitor study is that is PG&E was an average or slightly below average performer in 1996 in comparison to a peer group which includes a clearly high-cost utility like Con Ed. Substituting PG&E's 1999 forecast data for 1996 actual data shows that PG&E's costs may be even farther above average for 1999.

5.2.4 Econometric Study

PG&E engaged Christensen Associates (Christensen) to perform an econometric analysis which was used to derive a total cost function, which in turn was used to predict PG&E's cost of electric service. After normalizing for conditions that influence costs but are beyond the control of the utility's management, Christensen estimated that PG&E's costs are approximately 10% below the level predicted from a sample of 104 major utilities. PG&E concluded from this study that its total costs are significantly below the industry average.

ORA argues that the Christensen analysis suffers from the same flaw as the Monitor study in which PG&E's performance is compared to the average utility, rather than to efficient or superior performing utilities. ORA believes that the Christensen finding that PG&E's actual cost is approximately 10% below the model's prediction of PG&E's cost, does not support a conclusion of superior cost performance on the part of PG&E. To the contrary, ORA concludes that when properly compared against the best-in-class performers in the Christensen sample, PG&E's cost performance is shown to be consistently mediocre. ORA witness Kravtin replicated the Christensen study to perform a best-in-class cost analysis, and found the best-in-class performance is a negative 27%; the average of the five best performing firms is a negative 22.4%; and the average of the ten best performing firms is a negative 19.9%. ORA concludes that in comparison to these results, PG&E's negative 10% result is anything but superior, and in fact reflects mediocre performance.

In addition to what it considers to be this "overarching study design flaw," ORA finds the Christensen study to be flawed in other respects. In combination, ORA believes that these flaws render the study basically useless for purposes of assessing the reasonableness of PG&E's rate request. First, ORA notes, the study examines total costs of vertically integrated electric utilities, including the costs of electricity production that are no longer relevant to PG&E's performance as a distribution utility in the restructured electric industry environment or the revenue requirement in this proceeding. Even though Christensen was originally engaged to perform a distribution-only analysis for PG&E, this initial request was withdrawn by PG&E, and Christensen was eventually commissioned to perform a statistical benchmarking analysis of PG&E as a vertically integrated utility.

As it did with the Monitor study, ORA finds the Christensen study to be results-oriented. Christensen used what is referred to as a "between" estimation procedure where the model is run using one data point (averaged over multiple years) for each utility so that only one result is obtained for each utility over the sample period. Another type of estimation procedure commonly cited in the statistical literature and used by Christensen in other studies, including the one performed for SDG&E during this same period, is referred to as a "within" estimation procedure. For the "within" estimator, the model is run using data for each utility for each year so that a different result is obtained for each utility for each year of the sample period. At ORA's request, Christensen reran the PG&E model using the "within" estimator procedure, even though Christensen believes this procedure is biased against large utilities. The results were significantly different from those produced by using the “between” estimator. Specifically, the “within” estimation produces results for PG&E that range from a positive 16% to 22% indicating that PG&E’s actual costs are well in excess of its predicted costs. In ORA’s view, this completely negates Christensen’s purported finding that PG&E is efficient based on the “between” result.

Discussion

PG&E again contends that the FERC Form 1 data used in the econometric cost study does not contain the necessary specificity to allow an informed determination that any particular utility’s performance is best-in-class. Again, we are not persuaded that deficiencies in this data render the best-in-class analysis unusable. Scores on the order of negative 20% to negative 27% for other utilities, compared to PG&E’s score of negative 10%, call into question any conclusion that PG&E is among the more efficient performers.

PG&E’s decision to conduct an analysis of bundled, integrated utilities including generation is perplexing, given its initial request that Christensen perform an analysis limited to distribution-only utilities. The evidence shows that PG&E changed its work order due to resource constraints, but we share ORA’s concern regarding this explanation. During the same time period that Christensen performed the total utility cost analysis for PG&E, it performed a distribution-only analysis for SDG&E’s PBR proceeding using the same types of data and cost model it would have used had it performed such a study on behalf of PG&E. Regardless of PG&E’s reasons for conducting the study it did, its value is diminished by the inclusion of operations that are not directly at issue in this proceeding. This point is reinforced by the testimony of ORA witness Silkman, who found and concluded that:

> "[i]t is theoretically inappropriate and methodologically indefensible to use the historic performance of vertically integrated electric utilities to evaluate the operating efficiency of a utility in providing transmission, distribution and customer service functions..." (Exhibit 88, p. 5.)

PG&E witness Lowry provides a reasonable possible explanation -- bias against large firms -- for considering, then rejecting, the use of the "within" estimator. Thus, we are not prepared to conclude that the sole or primary reason for doing so was to manipulate the outcome in support of a pre-ordained conclusion that benefits PG&E. We do, however, find that application of the "within" estimator, and comparison of the results with those derived from using the "between" estimator demonstrates that seemingly esoteric, tendentious methodological issues can have a major impact on the outcome of studies such as this. Based on this methodological difference alone, PG&E's costs are either 10% below those predicted by the model or 16% to 22% above those predicted by the model. This range is too large to predicate any conclusion about the reasonableness of PG&E's costs.

5.2.5 Data Envelopment Analysis (DEA)

In addition to performing critical reviews of PG&E's cost studies, ORA engaged Economics and Technology, Inc. (ETI) to conduct a benchmarking analysis for transmission, distribution, and customer service functions using DEA. The analysis was performed by ORA witness Silkman.

DEA is a mathematical technique, based on the principles of linear programming theory, that is designed to assess how efficiently a firm, organization, agency, program, or other decision-making unit produces the output(s) it has been charged to produce. A firm is determined to be efficient if the ratio of its weighted outputs to its weighted inputs is greater than or equal to a similar ratio of outputs to inputs for every other firm in a sample. When the

DEA process is applied to each firm in the sample, the result is a production or efficiency frontier that consists of all possible linear combinations of efficient firms. Any firm on the frontier is efficient by definition.

Silkman states that although the use of DEA may be new to this Commission, it is an established part of the operations research field and has been used to evaluate electric utility performance before other state public utility commissions. Because it considers efficiency and provides information on how PG&E could adjust its various levels of inputs to produce outputs as efficiently as the peer utilities, ORA claims that the DEA study provides more relevant and valuable information than the cost studies offered by PG&E.

Based on 1996 expenditure data, Silkman concluded that PG&E operates at approximately 83.5% of the efficiency of, and is therefore not among, the more efficient utilities in the country. Silkman states this performance is slightly below the average for peer utilities providing similar services. Silkman further concludes that PG&E is spending too much on transmission and distribution O&M and on customer service functions even before the increases proposed in this GRC. In addition, according to Silkman, PG&E appears to have excess capacity in its transmission and distribution plant. To operate at an efficiency level comparable to the best in its class, PG&E would need to reduce its 1996 expenditures for transmission and distribution O&M by $74 million per year and by $141 million per year for customer services, or a total of $215 million per year.

PG&E takes the position that there are several reasons why one cannot conclude from a DEA study that PG&E is an inefficient utility. It therefore believes that this study can be used as no more than a guide for further inquiry, not as a tool to directly set rates. First, PG&E points out that DEA studies have inherent limitations. For example, PG&E witness Train notes, some “unincluded” or “unexplained” differences among firms are not explicitly incorporated into the analysis, yet DEA treats all unexplained differences in firms to be differences in efficiency, whether or not they actually are. Train concluded that the Texas Commission is well aware of this limitation, and that it uses DEA only as an indication that an inefficiency might be occurring, not as a tool to set rates or disallow costs. Another limitation found by PG&E is that DEA does not provide any measure of the uncertainty associated with its estimates. Also, according to Train, DEA ignores allocative efficiency, which means it cannot be used to compare firms' costs relative to one another.

Notwithstanding these limitations of DEA analysis, PG&E witness Train conducted several such analyses to evaluate ORA's study. When ORA's constraint of constant returns to scale was removed, he found that PG&E was fully efficient. When he limited the comparable utilities to those with at least 30% as many customers as PG&E, the DEA analysis again found PG&E to be fully efficient. When he limited the comparable utilities to those with at least 10% of the size of PG&E in terms of numbers of customers, the DEA assigned PG&E an efficiency score of 95%. He also found that an independent DEA analysis of utilities, conducted by Dr. Pollitt of Cambridge University, found PG&E to be an efficient utility.

Finally, PG&E finds certain flaws in ORA' study that, it believes, undermine the conclusions drawn by ORA. Noting that one of the claimed benefits of the DEA approach is that it shows what firms an inefficient firm should replicate in order to become more efficient, PG&E concludes that, according to ORA's calculations, it should replicate a firm made up of 84 firms like Concord Electric, which has just 26,000 customers. Train also notes that ORA's DEA analysis uses expenditure inputs for some variables, rather than quantity. Train claims that in order to use expenditure inputs properly, expenditures need to be adjusted for differences between firms in input prices, which ORA failed to do. PG&E finds that this has the potential to bias ORA's study against PG&E because, for example, wages in California are likely to have been higher than wages in the states containing several of the reference utilities that ORA identifies.

Discussion

ORA and PG&E appear to agree, and we concur, that ORA's DEA study should not be used to set rates directly. It would be wholly inappropriate, for example, to simply conclude that PG&E's request in this proceeding should be arbitrarily reduced by the $215 million efficiency gap that Silkman found, i.e., the amount by which PG&E would have to reduce transmission and distribution O&M expenditures to operate at best-in-class efficiency. The study is not robust enough to support such an action, and ORA does not make such a claim for it.

We find that the DEA study, which unlike PG&E's studies was designed as a benchmarking study, provides another strong indication that PG&E is probably not operating as efficiently as it could and therefore should be. It further weakens any claim that PG&E was demonstrably efficient in 1996, as well as any claim that test year forecasts based solely or primarily on PG&E's 1996 operations are presumptively reasonable. By concluding that PG&E is slightly below average even though it operates at about 84% of the efficiency of the best-in-class utilities, the study corroborates ORA's position that average performers are not necessarily efficient or reasonable performers. We note that our use of the analysis here, as another indication of possible inefficiency, is not unlike the use of DEA ascribed to the Texas commission by PG&E.

PG&E's conclusion that the implication of ORA's analysis is that PG&E should be broken up into 84 small firms like Concord Electric seems to miss the point of the study. As ORA explains, the point is that PG&E should look closely at how the most efficient utilities in the country deliver transmission and distribution services in order to adopt and implement their production technologies, including organizational structures. The objective is not to mirror the scale of companies that are able to produce the same types of outputs or deliver the same types of services in the most efficient manner. In the same vein, while we note that PG&E appears to be efficient when the comparison groups exclude small utilities, i.e., those with less than 30% and less than 10% of the number of customers served by PG&E, we also note that PG&E has not demonstrated any particular willingness, let alone eagerness, to even consider using this type of analysis to discover what aspects of the operations of these small firms it might seek to emulate in a quest for greater efficiency.

Finally, we take note of the debate over ORA's inclusion of the modeling constraint of constant returns to scale and PG&E's rejection of that constraint. This debate may provide yet another example of how seemingly esoteric methodological differences among expert witnesses produce significant differences in a study's outcome. In this case, we are satisfied that despite the obvious limitations on comparing PG&E to a utility with 26,000 customers, ORA has demonstrated sound reason for applying the constraint. Under a constant returns to scale assumption, a doubling of inputs will result in a doubling of outputs, such that the relative size of a firm is not a factor. By imposing constant returns to scale, Silkman correctly neutralizes the model's ability to effectively discount genuine operational inefficiency on the part of PG&E due to mere size. In a DEA model that allows for decreasing returns to scale, such as the alternative model run by PG&E, smaller but efficient peers drop out of the comparison group. That, it turn, has the effect of increasing the chances that the remaining larger firms will be found efficient.

5.2.6 Conclusion - Cost Studies

ORA is correct in arguing that we should be more concerned with whether PG&E is performing as well as the more efficient utilities, and is not merely operating at an average level of performance. We have no reason to conclude that merely because PG&E may have been performing at or near the average level of performance of any given group of utilities in 1996, its recorded costs form a sound basis for forecasting reasonable levels of costs in 1999. We agree that PG&E's ratepayers deserve better than a standard of average or even mediocre performance. Indeed, we interpret our statutory charge of ensuring the provision of adequate service at reasonable rates as requiring a higher standard of efficiency.

PG&E witness Ansar defines an economically efficient firm as one which minimizes the costs of providing given levels of services, pursues cost-effective technological changes over time, and chooses the socially-optimal mix of service characteristics, such as quality and reliability. He testified that PG&E conducted three of the cost studies at issue -- the unit cost study, the composite study, and the econometric analysis -- along with the total factor productivity study in order to evaluate PG&E's efficiency performance according to this definition. Yet, in its opening brief, PG&E states that its studies can only be used to provide a general indication of how its costs compare to the rest of the industry. We find that even though Ansar's objectives for the studies were only partially met by PG&E, we are able to draw certain conclusions from those studies and from ORA's (and Enron's) analyses of them.

The most significant observation that we make upon reviewing PG&E's studies is that PG&E has not proved that its costs of operations in 1996 were representative of the more efficient firms. At best, they show that PG&E was performing at or near average levels (or 10% below the predicted cost level in the case of the econometric analysis which also showed the more efficient firms having costs 20% to 27% below the predicted level). Moreover, when reasonable adjustments to PG&E's studies are made, such as excluding outlier values and using different yet supportable analytical methods, the studies support an alternative conclusion that PG&E's cost performance in 1996 was well below average, further undermining the claim that it is a demonstrably efficient operator. Finally, ORA's DEA analysis, while not without its own limitations, lends support to the conclusion that PG&E was not among the efficient operators in 1996. The results of these studies, taken as a whole, persuade us that the alternative conclusion is more likely to be the correct one. We note that this conclusion is consistent with the theory that after a period of underspending, then a wake-up call to bring its utility system up to par in the wake of outages and in the face of pending competition, PG&E substantially augmented its spending levels in 1996.

Again, our findings concerning these studies do not mean that we should apply the studies' outcomes directly to reduce PG&E's request in this GRC. We must still review PG&E's detailed requests on an account-by-account basis. But as we do so, we bear in mind not only the fundamental policy grounds, discussed earlier, for carefully considering each element of cost and weighing alternative forecasts, but also the distinct possibility that the particular test year cost forecast at issue reflects and incorporates the effects of inefficient operations. Ultimately, the revenue requirements established in this GRC should reflect the costs of doing business as an efficiently operated distribution utility, and no more. As ORA notes, PG&E may well be operating a safe, reliable, and responsive system now, but ratepayers are entitled to our assurance that PG&E is doing so efficiently as well.

6. Service Quality

ORA believes that the maintenance of customer service and other service quality standards is increasingly important in the face of electric industry restructuring and the advent of competition. While ORA believes that PG&E has been providing “high levels of customer service” (Exhibit 80, p. 5), it is concerned that PG&E may divert funds away from customer service activities, and that service may degrade unacceptably. At the same time, ORA notes that guaranteed standards of quality have been introduced in other jurisdictions.

ORA proposes the adoption of a Quality Assurance Program which centers on the offer of compensatory rebates to individual customers, payable as billing credits when PG&E fails to meet one of seven specific Quality Assurance Standards (QAS). The seven standards proposed by ORA are (1) meeting agreed-upon appointments set during the customer's contact with the Call Center; (2) performance of non-emergency investigations and repairs within an acceptable time frame; (3) performance of emergency investigations and repairs within two hours; (4) establishment of a course of action to resolve complaints, and communication of the course of action to the customer within three working days; (5) meeting agreed-upon installation dates for new services; (6) response to reports of service disruptions within four hours; and (7) restoration of service within 24 hours.

TURN recommends a combination of PBR performance measures, ORA’s QAS proposals, and additional service quality proposals and reporting requirements. TURN's proposal includes penalty-only indicators as well as service guarantees with compensatory rebates.

PG&E opposes ORA’s and TURN's service quality proposals in this proceeding. PG&E acknowledge that this GRC proceeding has an adequate record on which to consider adoption of customer service and reliability performance measures. However, PG&E contends that it has demonstrated its commitment to maintaining a high level of service by spending well above the levels adopted by the Commission since 1996, and by its request in this GRC to maintain these current service levels. Moreover, PG&E does not believe that it is necessary to adopt service guarantees in this proceeding. PG&E proposes that we fully address all aspects of PG&E's customer service and reliability performance measures in its pending PBR application (A.98-11-023).

Discussion

ORA contends that this GRC is the appropriate forum to propose a QAP Program for several reasons. We agree. The General Rate Case is the traditional forum in which the revenue requirement associated with providing reasonable adequate service is traditionally made. Defining the level of service and appropriate enforcement mechanisms in this GRC will assist PG&E and the public in finding common ground on the level of service expected of a franchised provider of distribution service. We recognize that several of the parties, including PG&E, expect to address service quality issues in PG&E's PBR proceeding, A.98-11-023. Those service quality indices for which there is an insufficient record in this proceeding, including system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) should be addressed specifically in A.98-11-023. This is the proper place to institute customer service standards.

The record is sufficient to adopt the quality assurance program proposed by ORA, and we will do so. The elements of the Quality Assurance Program are a set of specific standards in areas affecting customer service and a set of compensatory rebates for customers if the standards are not met. We adopt

ORA's proposed Quality Assurance Program and the Quality Assurance Standards contained therein.

The standards proposed by ORA are:

- Quality Assurance Standard (QAS)1 -- missed appointments

PG&E will meet the agreed upon appointment time set with a customer during the contact with the Call Center.

- QAS2 – non-emergency service investigations/repairs

PG&E will agree to investigate within a time frame acceptable to both the customer and the field dispatch. Due to the non-emergency nature of the investigation (Check meter) these investigations can be scheduled to fit the field service representative's schedule for the coming week. The field dispatch office has the field service representative's schedules and can assign the investigations to the representatives to balance their work load. If access to the customer's premises is required, then an appointment is required as well and QASI is applicable. Failure to meet the QAS2 will result in a $50 credit to the customer's account.

- QAS3 -- Emergency Service Investigations/repairs

PG&E will respond immediate to a request for Emergency service investigations/repairs. Under normal conditions, there should be no excuse for a response to be delayed over two hours. An emergency service call is immediately assigned to a field service representative by the dispatcher. The field service representative will move an emergency call ahead of all other calls of a non-emergency nature. Failure to meet the QAS3 will result in a $100 credit to the customer's account.

- QAS4 -- Complaint Resolution

PG&E will work to resolve customer complaints as quickly as possible. Upon receipt of a complaint PG&E should initiate an investigation as to the nature of the complaint and decide a course of action to resolve the complaint. This course of action needs to be communicated to the customer within three working days. PG&E's final resolution of the complaint should be communicated to the customer within five working days. PG&E's failure to communicate its resolution of the complaint with five working days will result in a $20 credit to the customer's account.

- QAS5 -- New Installations

PG&E will meet the agreed upon installation date for new service installations. The customer arranges a date for installation of a new meter and service turn-on with a call to the Call Center. This is typically an all-day appointment, and there is no need to enter the customer's premises (otherwise QAS1 would apply). The field service representative may reschedule the original appointment with the customer to respond to emergencies. At that time the field service representative updates the appointment through the FAS unit in his vehicle. The rescheduled time then becomes the new appointment date to meet to keep to the QAS. Failure to meet the QAS5 will result in a $50 credit to the customer's account.

- QAS6 Response to Service Disruptions

PG&E will respond to calls reporting service interruptions within 4 hours, either by restoring service or informing the customer when service restoration is expected. Under normal operating conditions a field service representative will be dispatched to the premises to determine the causes of disruption. After making sure conditions are safe, an investigation is initiated to determine cause, course of action, and estimated time for restoration of service. The information is input to the FAS, automatically updated to the Call Center, and the IVRU automatically contacts the customer with a time when service will be restored. Failure to meet the QAS6 will result in a $50 credit to the customer's account.

- QAS7 -- Restoring Service

PG&E will restore service within 24 hours. Customers should not have to be without service for more than 24 hours, unless the cause is absolutely beyond PG&E's control. Failure to meet the QAS7 will result in a $50 credit to the customer's account for each 24-hour period the customer is without service.

TURN has some suggested modifications to ORA's program. ORA has proposed two service guarantees, QAS1 on missed appointments and QAS5 on meeting new service installations, which measure a similar concept to that of PG&E's QSE+ Question 11. That concept is meeting time commitments to the customer. TURN favors the ORA's indicators (perhaps combined into one service guarantee) because the customer receives some compensation for the inconvenience caused by the utility's missed commitment.

Several of ORA's quality assurance standards deal with different aspects of outage situations -- QAS3 (emergencies), QAS6 (service disruptions), and QAS7 (restoration guarantee). To more evenly balance the measurement of requests, TURN recommends reducing the number of these mechanisms. QAS7, restoration of service within 24 hours, should be applicable to situations other than serious emergencies, as Edison's is. We accept TURN's recommendation.

An essential feature of ORA's Quality Assurance Program is the use of "compensatory rebates" penalties. Penalties that accrued to the customer when PG&E fails to meet a quality assurance standard. This is a self-enforcing mechanism that may create a significant incentive for PG&E to meet the standards. As ORA points out, this has been the apparent effect of its adoption in the United Kingdom. However, we are concerned that the levels proposed by ORA may be excessive, and may create perverse incentives for customers. Will therefore modify the QAS penalties proposed by ORA. The penalties we adopt are:

- QAS1 (missed appointments) $25 credit
- QAS2 (non-emergency investigations) $25 credit
- QAS3 (emergency service investigations) $100 credit
- QAS4 (complaint resolution) $25 credit
- QAS5 (new installation) $50 credit
- QAS6 (service disruptions) $25 credit
- QAS7 (service restoration) $25 credit

Given the substantial additional revenues over the 1996 General Rate Case authorized by this Decision, we believe that the adoption of these customer service standards and the creation of a mechanism for permitting customer self-enforcement represents a fair tradeoff. The novelty of the compensatory rebate enforcement mechanism requires that we monitor the program to determine its efficacy, and the potential for abuse. We will adopt ORA’s proposal to require PG&E to report monthly on compliance and penalties to the Energy Division and will consider modifications to the program in the next GRC. We expect that the number of violations of the mandatory standards and the amount of money paid as compensatory rebates will show the precipitous decline for PG&E that occurred in the United Kingdom, according to ORA.

7. Electric Revenues, Expenses and Capital

7.1 Revenues

7.1.1 Customers and Sales - Bypass

The only outstanding issue regarding customers and sales forecasts for 1998 and 1999 is the forecast of electric bypass. PG&E forecasts a loss of electric sales due to four types of bypass: self-generation, including over-the-fence sales; bypass to irrigation districts; bypass to other transmission and distribution providers; and gas-fired engines for agricultural water pumping. PG&E's total bypass forecast for the test year is 7,255,088 MWh. Weil believes that this forecast is based in part on unrealistic assumptions. Weil accepts PG&E's estimates for traditional self-generation and agricultural pumping, but disputes PG&E's forecasts of over-the-fence, irrigation district, and other types of bypass. Weil recommends adoption of a bypass forecast of 6,650,852 MWh.

In support of his position that parts of PG&E's bypass forecast are arbitrary and inflated, Weil points out that PG&E forecasts a tripling of over-the-fence bypass from 1997 to 1998 and another two-thirds increase from 1998 to 1999. In addition, PG&E predicts that Merced Irrigation District (MID) bypass will grow from 100,518 MWh in 1997 to 215,924 MWh in 1999, that other irrigation district bypass will increase from 47,700 MWh in 1997 to 146,600 MWh in 1999, and other bypass elements will double from 1998 to 1999. Weil's recommendation is based on increasing over-the-fence, MID and other irrigation district bypass by 5% per year over PG&E's 1997 estimates.

One of the assumptions underlying PG&E's irrigation district bypass forecast is that the districts will use all of the CTC exemptions granted under Sections 374(a)(1) and 374(a)(2) during the entire test year. In Weil's opinion, the lead times needed for irrigation districts to accomplish bypass projects make this assumption unrealistic. He testified that included among the steps for successful completion of a bypass project are feasibility studies, political approval for quasi-governmental agencies, Commission approval, engineering design and environmental plans, and construction of distribution facilities. Weil expects PG&E to resist loss of local distribution customers, which will add time to the bypass project process. Weil also notes that PG&E's assumptions that transmission and distribution and five-mile bypass will cause a market share loss of 12.5% by 1999 and that over-the-fence bypass will cause a market share loss of 55% by 1999 are matters of judgment. Finally, Weil points to an internal inconsistency in PG&E's presentation in that PG&E's electric capital additions forecast includes no reduction to account for distribution facilities taken over by other entities, and neither of PG&E's plant forecast witnesses were aware that PG&E's sales forecast includes a reduction for distribution bypass.

In response to Weil's claims, PG&E states that it expects that irrigation districts will take full advantage of their CTC exemptions. For example, as PG&E witness Aslin notes, the Modesto Irrigation District fully used its allocated CTC exemptions in 1997 and 1998, inducing large PG&E customers in Oakdale, Riverbank, and Ripon to take its offer of CTC-exempt service. There is also evidence that several other irrigation districts, both with and without CTC exemptions, pose a threat to PG&E of loss of sales. PG&E notes that on September 16, 1998, in Docket No. EL98-46-000, FERC ordered PG&E to interconnect with Laguna Irrigation District (Laguna) to allow Laguna to serve 19 retail customers currently served by PG&E. FERC also established an aggressive schedule for PG&E and Laguna to negotiate the details of the interconnections. PG&E anticipates that whatever interconnection agreement is finally developed between it and Laguna will become the template for interconnection agreements with other irrigation districts possessing CTC exemptions. PG&E concludes that the activities of the irrigation districts to date, combined with this recent FERC order, argue strongly for the proposition that the irrigation district CTC exemptions will be fully utilized, which is the underlying assumption of PG&E's forecast of irrigation district bypass.

PG&E criticizes Weil's forecast of irrigation district bypass as unsupported in several respects. First, PG&E notes that Weil did not make a study of lead times for bypass projects. Nevertheless, Weil concluded that since only 17 months remained from the date of his testimony to the end of the test year, it seemed unlikely that PG&E would lose test year revenues to new projects not already identified and well underway. PG&E believes that this assertion is undermined by Weil's concession that it would take but a "couple of weeks" for an irrigation district with CTC exemptions to install a transformer, a service drop and a meter, which is precisely the sort of interconnection in Laguna. PG&E also notes that Weil was not familiar with the FERC's Laguna decision at the time of his testimony; had not made any effort to confirm the accuracy of Aslin's rebuttal testimony addressing irrigation district bypass; had not spoken with employees of the irrigation districts that are competing with PG&E; and had no familiarity with the number of CTC exemptions granted the irrigation districts or how the irrigation districts have utilized them.

Discussion

Weil agrees with a basic premise of PG&E's bypass forecast -- that distribution bypass is increasing over time. The dispute essentially boils down to a matter of judgment regarding the pace at which irrigation district bypass projects and other forms of bypass will be implemented.

There are well-supported arguments on both sides of the issue. On the one hand, Weil has demonstrated that there are significant impediments to completion of bypass projects. On the other hand, competition and CTC exemptions provide a strong incentive for bypass to occur, and PG&E has demonstrated that bypass will continue to occur at an accelerated pace. PG&E has also demonstrated that Weil failed to consider recent events that suggest more rapid development of bypass than is indicated by his analysis.

On balance, we are not persuaded that it is reasonable to conclude that all bypass will result in idled facilities, that irrigation districts will have used all of their CTC exemptions as of January 1, 1999, and that other types of bypass will cause large market share losses. The fact that PG&E's plant and capital additions witnesses were unaware of PG&E's bypass forecast adds to our doubt regarding PG&E's forecast. We are also not persuaded that Weil's estimates of 5% growth in irrigation district and over-the-fence bypass reflect the actual pace with which this phenomenon is occurring. In our judgment, the two bypass forecasts in the record may fall outside the range of likely outcomes. Accordingly, we adopt the midpoint, 6,952,970 MWh, as a more likely and therefore more reasonable bypass forecast than either PG&E's or Weil's forecasts. With this modification, we accept PG&E's customer and sales forecast.

Weil points out that the bypass forecast is offered and used to forecast revenues at present rates. He argues against using the forecast for any other purpose, and therefore recommends that we adopt it "for the limited purpose of calculating present rate revenues." This unopposed request is reasonable and is hereby adopted.

7.1.2 Revenues at Present Rates

As shown in the comparison exhibit, PG&E and ORA agree on the forecast of billed revenues at present rates based on the customer and sales forecast. The total Electric Department revenue at present rates forecast, including

FERC-jurisdictional and CTC-related functions, is $7.403 billion. This total consists of $3.856 billion non-general revenue and $3.548 billion GRC revenue.

FEA proposes two adjustments to electric revenues. The first adjustment reflects a correction to the amounts used by PG&E in its original and March Update filings for Other Operating Revenues. It would reduce Other Electric Revenues by $4,694,525. FEA makes the proposal to correct errors acknowledged by PG&E caused by its use of incorrect numbers for the Contributions In Aid of Construction (CIAC) tax adjustment and the incorrect unbundling of the CIAC adjustment. The second adjustment proposed by FEA increases electric operating revenues by $18 million. It is made to reflect adjustments proposed by ORA in its Report on the Results of Examination, which FEA witness Smith finds to be credible (although he did not independently confirm them).

PG&E updated its GRC proposal in the comparison exhibit to reflect positions of record, including those set forth in rebuttal testimony and changes made by witnesses during hearings. FEA has not demonstrated that the changes set forth in its testimony are required in connection with the final PG&E position as set forth in the comparison exhibit. With adjustments to reflect our adopted bypass forecast, we adopt PG&E's present rate revenue forecast as reasonable.

7.2 Expenses

7.2.1 Generation

7.2.1.1 Inclusion of Generation Expenses in This GRC

Even though the focus of this GRC is on utility distribution services, PG&E presented a showing on generation production expenses related to its nuclear facility at Humboldt Bay, its steam and other production facilities, and its hydroelectric facilities. PG&E did so primarily for the purpose of common cost allocation. In addition, PG&E presented hydroelectric and geothermal production expenses to comply with D.97-12-096, which established the alternative revenue requirement mechanism for hydroelectric and geothermal generation units. Finally, PG&E included production expenses related to the Humboldt Bay SAFSTOR activities because, PG&E believes, this GRC is the only vehicle available for recovery of the costs of these ongoing safety-related activities.

To the extent consistent with restructuring statutes and decisions, we concur with CFBF that we should separate generation where necessary to ensure that distribution customers pay only for distribution services. However, PG&E has demonstrated that it is necessary to consider generation costs for purposes of common cost allocation. In addition, we consider these costs pursuant to the hydroelectric and geothermal generation revenue requirement mechanism adopted in D.97-12-096. We address below PG&E's proposal for inclusion of Humboldt SAFSTOR expenses in this GRC.

In its original request, PG&E included $32.7 million for employee transition costs such as severance, outplacement, and retraining, for employees affected by restructuring. PG&E allocated $19.2 million for such expenses to steam and other production accounts and $13.5 million to hydraulic production accounts. While PG&E's testimony is somewhat ambiguous, we understand that it has agreed to the exclusion of employee transition costs from its GRC request, including its hydroelectric and geothermal ratemaking mechanism, thereby removing several issues raised by opponents of this proposal. We concur that these are transition costs which should be addressed in the appropriate transition cost recovery proceeding pursuant to D.97-11-074 and Section 375, and not in this proceeding.

7.2.1.2 Nuclear Production - Humboldt SAFSTOR

To maintain the Humboldt Unit 3 facility in the SAFSTOR custodial mode, PG&E incurs O&M expenses which include those related to environmental monitoring and security. In this section we address issues regarding both the appropriate level of expenses and the vehicle for cost recovery.

PG&E presented a production expense forecast of $4.148 million related to the Humboldt SAFSTOR Costs UCC. This estimate is based on recorded 1996 data adjusted for changes in the charging of fossil and nuclear costs resulting from an analysis undertaken by PG&E in 1996. Weil forecasts expenses of $3.967 million. This forecast is based on his use of a five-year average of recorded expenses (1992-1996) to create a base number, and application of the same adjustment used by PG&E to arrive at his estimate.

PG&E disputes Weil's contention that a five-year simple average provides a more reasonable basis for forecasting test year expenses. Using the same five years of data, and applying a linear least squares fit, PG&E witness Bosscawen concluded that there was a clear upward trend in costs. PG&E's alternative calculation produces a forecast of $4.249 million. PG&E concludes that its more conservative forecast of $4.148 million is reasonable and should be adopted.

The use of multi-year averages as the basis of test year forecasts can eliminate errors associated with year-to-year variations. Historical data from several years can also be used to identify possible trends. In this case, in the face of evidence that the expense increased in 1997, we adopt PG&E's forecast of $4.148 million as reasonable.

ORA does not contest PG&E's forecast amount for Humboldt SAFSTOR O&M, but it takes the position that this expense should be excluded from the revenue requirement set in this GRC. PG&E takes the position that, pursuant to D.98-03-050 and Section 379, it is appropriate to establish a nonbypassable charge for recovery of this decommissioning expense. CFBF concurs with PG&E ‘s categorization of Humboldt SAFSTOR expenses as part of nuclear decommissioning charges.

In its GRC application, PG&E provided notice that the revenue requirements associated with SAFSTOR costs were included in its request. ORA has not demonstrated that another proceeding is more appropriate for the purpose of setting a nonbypassable charge for Humboldt SAFSTOR. Therefore, in accordance with Section 379, we authorize PG&E to establish such a charge for collection of the revenue requirement for this decommissioning expense, subject to the electric rate freeze mechanism.

7.2.1.3 Steam and Other Production

PG&E estimates 1999 total production expenses for Steam and Other Production, including CPUC and FERC jurisdictional expenses, at $169.7 million. ORA’s estimate is $168.8 million. PG&E and ORA disagree on expense forecasts for Gas and Electric Supply and regulatory fees. Other parties contest PG&E’s forecast and UCC assignment of the Gas and Electric Supply function, its forecast and UCC assignment of the Sales to the PX function, and its forecast for irrigation district O&M expense.

7.2.1.3.1 Regulatory Fee Adjustment (Account 502)

PG&E pays regulatory fees to various agencies such as air pollution control districts and water quality control boards to maintain permits to operate power plants. Based on a survey of employees directly involved with the various regulatory agencies, PG&E concluded that fees would increase by $862,000 in 1999, broken down as follows: $330,000 for Pittsburg, Contra Costa and Potrero; $472,000 for Moss Landing; and $60,000 for Hunters Point and Oakland. PG&E later removed the $472,000 forecast increase for Moss Landing due to the sale of that facility. The revised forecast of regulatory fee increases is $390,000.

ORA and Weil claim that PG&E provided insufficient documentation regarding its proposed increase in regulatory fees, and therefore recommend no increase. ORA also believes that the expenses could be avoided until the plants are sold.

We find insufficient analytical support for inclusion of the increased fees forecast by PG&E. As Weil points out, PG&E justified its forecast largely on the basis of assumed 10% annual increases in fees. We find this unpersuasive, particularly in light of modest inflation, and therefore reduce PG&E's forecast for Account 502 by $390,000.

7.2.1.3.2 Irrigation District O&M (Account 555)

PG&E enters into power purchase contracts pursuant to which it receives the full output of generation facilities owned by seven irrigation districts: MID, Nevada Irrigation District, Oroville-Wyandotte Irrigation District, Placer County Water Agency, Solano Irrigation District, Tri-Dam Project, and Yuba County Water Agency. PG&E operates the facilities and assumes the obligation to pay the districts' project-related expenses. PG&E's test year forecast of $27.9 million for the costs of this obligation reflects increased expenses of $6.8 million, or 32.1%, above the 1996 actual expense of $21.1 million. Except for the Tri-Dam Project, whose costs are fixed by contract, PG&E's estimates are based primarily on a review of the irrigation districts' budgets.

Noting that the increase of 32.1% is equivalent to an annual escalation rate of 9.7%, Weil argues that PG&E's forecast for this expense is unjustified and excessive. Weil believes that it is more reasonable to apply a 3.5% escalation factor, which, he points out, has been used by PG&E historically as a default where projections are not available. Applying this escalation rate to the 1996 irrigation district O&M recorded expenditures (for all but the Tri-Dam Project) produces a total increase of $2.157 million. Weil recommends that this increase be allowed in place of PG&E's proposed $6.774 million increase.

Weil contends that the irrigation districts budgets relied upon by PG&E do not represent showings of necessity and reasonableness. He notes, for example, that the funding request for the Nevada Irrigation District’s Yuba-Bear River Project includes only single line item entries as project justifications, and these account for only 28% of the dollars requested. Similarly, Weil notes that a 204% annual increase over 1996 actual costs for the Solano Irrigation District is supported by very little information beyond a mere listing of amounts for five budget categories.

In defense of its forecast in the face of Weil’s criticisms, PG&E faults Weil’s recommendations for his failure to test his conclusion by analyzing the underlying data and discussing these forecasts with the irrigation district personnel who prepared them.

Notwithstanding the number of pages of irrigation district budgets that PG&E has furnished to this record, PG&E has not demonstrated to our satisfaction that these budgets can be relied upon as the sole support for increases of the magnitude it is forecasting, i.e., nearly 10% per year. Even though Weil did not fully investigate the numbers in the irrigation district budgets, he has cast doubt on their reliability for purposes of this GRC. PG&E has not persuaded us that it did much more than Weil did to investigate the reliability of the budgets. In the absence of a more reliable bottoms-up forecast, we adopt as reasonable Weil’s recommendation for using a 3.5% escalation factor, along with the actual contract formula for the Tri-Dam Project. PG&E’s

forecast should therefore be reduced by $4.617 million, which is the difference between the increases forecast by PG&E and Weil.

7.2.1.3.3 Power Exchange (PX) Sales (Account 557)

PG&E has identified expenses which it expects to incur for systems needed to bid PG&E energy into the PX and handling billing and settlement with the ISO. The costs of managing ISO contracts, hydroelectric water management, and Power Generation Department budgeting functions are included in this Sales to the PX category. PG&E created a new organization which is responsible for these functions by moving existing employees from former Power Generation Departments and other parts of PG&E. The associated costs are embedded in base revenues, although they were previously recorded in other accounts. PG&E also hired new employees and contractors to carry out these functions. The $4.219 million cost of the new employees and contractors is therefore incremental.

PG&E's 1999 forecast for these functions is $8.545 million, including both CPUC and FERC jurisdictional expenses. PG&E maintains that it will incur these expenses as ongoing costs in 1999 and beyond, until market valuation of its generating facilities occurs. PG&E initially included this amount in its proposed Electric Department revenue requirement. PG&E later modified its proposal to instead allocate this expense among the Fossil, Geothermal, and Hydroelectric UCCs in the amounts of $3.957 million, $0.326 million, and $4.262 million, respectively. PG&E notes that the amount allocated to fossil expense will be at risk for market recovery. PG&E made the allocation using rules established for FERC Form 1. As PG&E explains, the costs are allocated to individual fossil, geothermal, and hydroelectric Responsibility Cost Centers (RCCs). Essentially, 46% is allocated to fossil generation, 4% to geothermal, and 50% to hydroelectric.

Under the alternative hydroelectric and geothermal revenue requirement mechanism adopted in D.97-12-096, the associated revenue requirement will be netted against revenues. ORA agrees with PG&E's recommendations for the costs of sales to the PX and related expenses.

Enron contends that the $4.2 million incremental amount should be considered in the Commission's Section 376 proceeding, not in this GRC. Alternatively, Enron proposes that PG&E's request in this GRC be reduced to $4.3 million on the basis of what it believes to be PG&E's failure to show that its costs are just and reasonable. Enron is also concerned that the expenditures may be non-recurring due to the pending divestiture of additional fossil plants and geothermal plants and the proposed spin-off or sale of hydroelectric facilities. Enron further disputes PG&E's allocation of the expense, contending that the allocation to hydroelectric is excessive. Enron proposes that the allocation to fossil, geothermal, and hydro be made using kilowatt hours (kWh).

PG&E responds that the functions to be funded in this GRC are ongoing, since it will need to bid energy into the PX, handle billing and settlement with the ISO, and manage its contracts with the ISO until all of its generation plants are market-valued. PG&E also contends that Enron's comparison of PG&E's forecasts with those of Southern California Edison Company (Edison) and SDG&E in their Section 376 applications is invalid. Unlike PG&E, which will retain substantial generation resources in the test year, SDG&E planned to have sold all of its generation resources by the end of 1998. Furthermore, SDG&E included only incremental costs in its Section 376 filing, while PG&E included the non-incremental costs of ongoing operations in its GRC estimate. PG&E also notes that the costs which Edison included in its Section 376 showing represent only incremental costs necessary to develop transactional software and to purchase computer hardware; not ongoing operating costs.

Discussion

Enron has not persuaded us that any portion of the costs of sales to the PX which PG&E has presented in this GRC should be recovered under PG&E's Section 376 proceeding. As PG&E explains, in this GRC it seeks recovery of restructuring implementation costs that will be incurred in 1999 and beyond. Its Section 376 application seeks to recover restructuring implementation costs incurred in 1997 and 1998. There appears to be no issue of double recovery in different proceedings. Moreover, although Enron believes that Section 376 treatment would facilitate comparisons with Edison and SDG&E, PG&E has shown that the costs for these utilities are not directly comparable to those being incurred by PG&E.

We do concur with Enron's position that it would be inappropriate to include non-recurring costs of sales to the PX and related expenses in ongoing revenues authorized in this GRC. Our concern in this regard is mitigated, but only partially so, by the fact that the amounts allocated for fossil expenses are at risk for market recovery. With respect to the amounts allocated to hydroelectric and geothermal categories, we note that the alternative hydroelectric and geothermal generation revenue requirement mechanism adopted in D.97-12-096 is operative only as long as these generation assets are owned and operated by PG&E, and in no event after the end of 2001. (D.97-12-096, pp. 9-11.) Thus, any problem of inappropriate inclusion of non-recurring costs would be limited to this time period. Still, we find fault with PG&E's forecast of $8.545 million.

First, activities funded under this category are new with the advent of ISO and PX operations, so it is not possible to rely on historical information to gauge the reasonableness of and the need for the proposed expenditures. Nearly half of the total amount, or about $4.2 million, is incremental. Under the circumstances, we would have expected a more affirmative demonstration of the necessity and reasonableness of the proposed level of expenditures. PG&E has provided numerical data in rebuttal testimony (Exhibit 27, Chapter 3, Attachment D) along with some descriptive statements, but it has not demonstrated to our satisfaction how its bottom-up analysis of the functions funded by this category results in the forecasted amount.

Also problematic is the fact that PG&E found no reason to adjust its forecast with the Wave 1 divestiture, i.e., the sale of its Moss Landing, Morro Bay, and Oakland generating facilities. Moreover, PG&E has no plans to adjust this expense with successive divestitures of generation assets, even though, as PG&E acknowledges, this category of expense will be eliminated when all of its fossil, geothermal, and hydroelectric plants have been divested or shut down. The picture that emerges is that PG&E either believes or assumes that it will incur no less than $8.545 million each year for sales to the PX so long as it owns and operates a single megawatt of fossil, geothermal, or hydroelectric capacity. At a minimum, PG&E apparently believes that it is reasonable to charge expenses of $4.262 million annually for sales to the PX for its hydroelectric facilities until it has divested all of those facilities. We recognize that costs for sales to the PX probably do not vary proportionately with the number of generating plants remaining or the capacity or output of those plants. However, PG&E's implicit position that there is no relationship whatsoever between the number, value, or capacity of its remaining generation assets and the expenses it will incur in managing sales to the PX and related functions strikes us as untenable.

We conclude that PG&E has failed to provide adequate justification for this additional expense.[11] We therefore adopt Enron's proposal to exclude $4.2 million of incremental expenses in Account 557 for sales to the PX category. The remaining $4.3 million will be allocated to fossil, geothermal, and hydroelectric UCCs using PG&E's allocations. Enron has pointed out problems with this allocation scheme, but has not persuaded us that its alternative of using production output produces a better allocation. In the event that PG&E divests or shuts down all of its remaining fossil and geothermal plants, PG&E shall not reallocate sales to the PX costs to remaining hydroelectric facilities.

7.2.1.3.4 Gas and Electric Supply (Account 557)

Under electric industry restructuring, PG&E expects to incur costs for submitting customer demand bids to the PX, scheduling must-take resources with the ISO, collecting and processing meter data for demand and must-take generation, and handling invoices and settlement with the ISO and PX. PG&E created a new organization to carry out these activities. As with the sales to the PX function, PG&E staffed this organization with employees transferred from other organizations, new employees, and contractors.

PG&E forecasts total expenses of $10.524 million for these functions, which it refers to collectively and categorizes as Gas and Electric Supply, or Utility Energy Supply. This amount includes both CPUC and FERC jurisdictional expenses. The total is composed of $7.77 million associated with PG&E's transfer

11 In its reply brief, PG&E appears to argue (at p. 29) that we should accept its forecast because Enron, a competitor of PG&E, is the only party to contest it. We remind PG&E that even if ORA supports, or does not contest, one of its forecasts, PG&E's burden of proof to show the need and reasonableness of a predicted expense never shifts. The failure of ORA (or any other party) to take a position in opposition to PG&E on any issue does not give PG&E a free pass on that issue.

of personnel from A&G accounts and $2.754 million for new, or incremental, costs. PG&E contends that the Gas and Electric Supply function is an ongoing distribution function that should be paid for by distribution customers.

Unlike Enron and Weil, ORA accepts this forecast for Gas and Electric Supply. However, ORA joins Enron and Weil in disputing PG&E's proposals for assignment of this category of expense to the distribution function and for cost recovery from distribution customers.

Weil recommends that the Commission disallow recovery of the incremental costs associated with this UCC. Weil does not dispute the proposition that new activities might be necessary, but he contends that PG&E's justification for the forecast consists of only accounting information and limited direct and rebuttal testimony that provides inadequate explanation. Weil concludes that PG&E has not demonstrated a connection between the activities and the level of its funding request. With respect to categorization of these expenses, Weil contends that PG&E's proposal to have distribution customers pay for these generation-related costs would result in an inappropriate subsidy. Weil acknowledges that since PG&E incurs generation-related costs on behalf of bundled service customers, it may be necessary to create a rate surcharge or adder for these customers.

As with its recommendation for the Sales to the PX functions, Enron recommends that the incremental portion of this expense forecast be removed from the GRC and considered in PG&E's Section 376 proceeding. Enron also recommends that $9.524 million, or all but $1 million, be recovered through the PX charge and not through distribution rates. In the absence of a breakdown of the total Gas and Electric Supply expense forecast among the various functions, Enron believes that an estimate of $1 million for scheduling must-take resources is reasonable as a distribution expense.

Discussion

As we determined in connection with PG&E's Sales to the PX request, we find that Enron has not justified consideration of the incremental expense in PG&E's Section 376 proceeding. Similarly, PG&E has again failed to persuade us that the incremental expenses should be approved. If, as Weil asserts, PG&E's showing on incremental sales to the PX function was thin, its showing here is equally so. We adopt a forecast of $7.77 million for Gas and Electric Supply. As explained below, this amount should be allocated to generation, not distribution as proposed by PG&E.

PG&E has shown that the functions it includes under its Gas and Electric Supply category will continue even after it has divested or otherwise market-valued its non-nuclear generation assets. It is also clear that, at least in part, PG&E will continue to incur these expenses as a result of its role as a default provider of bundled services. However, PG&E has not demonstrated that these are distribution functions that should be funded by all distribution customers, including direct access customers. At least in significant part, they are the same functions provided by scheduling coordinators and energy service providers on behalf of direct access customers. PG&E witness Bosscawen acknowledged that PG&E does not bid demand into the PX on behalf of direct access customers. As Enron has explained, if PG&E collects costs for these activities from all distribution customers, direct access customers will pay twice for the same service. This is inconsistent with our policy, which we articulated in D.97-08-056 (mimeo., at p. 8), to avoid the allocation of costs of competitive or potentially competitive services to monopoly functions, and, more specifically, to avoid the allocation of generation costs to distribution customers.

Accordingly, these generation-related expenses should not be assigned to a distribution UCC. We will entertain proposals by PG&E for recovery of these expenses from customers on whose behalf they are performed. We do not determine at this time the appropriate mechanism for such recovery, whether it be a rate surcharge or adder for bundled service customers, a credit for direct access customers, or otherwise. Also, while we ordinarily do not permit second opportunities for applicants to demonstrate the reasonableness and necessity of proposed expenditures, in view of the unique circumstances of this issue we will permit PG&E to make a showing on Gas and Electric Supply incremental expenses in the event it makes a cost recovery proposal as discussed herein.

7.2.1.4 Hydraulic Production

PG&E forecasts 1999 hydraulic production expenses of $68.276 million, while ORA's forecast is $56.397 million. These amounts include both the CPUC and FERC jurisdictional expenses. The differences between PG&E's and ORA's estimates are attributable to disputes regarding FERC license condition costs, non-routine maintenance, and the costs of flood studies. Enron and Weil join ORA in one or more of these disputes. In addition, Enron has stated its disagreement with PG&E's inclusion of the El Dorado hydroelectric facility expense in these forecasts. We address these disputes below. All of these disputes affect only the Electric Generation - Hydroelectric Generation Facilities UCC.

7.2.1.4.1 Flood Studies (Account 537)

To reflect revised rainfall intensity tabulations issued by the National Weather Service, PG&E expects to incur expenses to study spillway adequacy. PG&E considers these flood studies to be a high priority safety matter. PG&E used its professional judgment in estimating the cost to do this work at $200,000 per year for five years--$150,000 for contracting and $50,000 in PG&E labor per year. Since the $50,000 in PG&E labor is not incremental, PG&E requests an increase of $150,000 for 1999.

ORA, Enron, and Weil disputed this estimate based on the premise that PG&E will divest its hydroelectric facilities and the new owners who will be the beneficiaries of these expenditures should fund these studies. Weil also claims that PG&E has not justified the level of expense.

While we are generally leery of forecasts based solely on judgment, PG&E has shown that its forecast of $150,000 for flood studies is reasonable and should be allowed. We are persuaded that this is a dam safety issue which should not await completion of divestiture or other market valuation of PG&E's its hydroelectric facilities.

7.2.1.4.2 El Dorado Project (Accounts 539, 543, 545)

ORA initially contested PG&E's forecast of costs for maintaining and operating the El Dorado Project water system and maintaining the FERC license, but now agrees that it should be adopted. In its prepared testimony, Enron stated its concurrence with ORA's initial recommendation for El Dorado costs, but provided no independent justification for its position. In its reply brief, Enron stated that it takes no position on El Dorado expenses.

PG&E believes that the forecast costs associated with maintaining and operating the water system should remain in this GRC until the Commission approves A.97-11-012 or takes other action that would obviate the need for these costs to be incurred. PG&E also notes that if the Commission approves its El Dorado Section 851 request (A.98-04-016), the El Dorado expenses will be removed from the GRC revenue requirement associated with PG&E's hydroelectric facilities.

The Commission approved PG&E's Section 851 request by D.99-09-066 dated September 16, 1999. Pending exercise of the authorization therein, it is reasonable to include costs associated with maintaining and operating the El Dorado water system. We address procedural issues related to the El Dorado outage investigation, I.97-11-026, in Section 12.3 of this decision.

7.2.1.4.3 FERC License Conditions (Account 539)

PG&E forecasts additional expenses of $11.110 million for fulfilling conditions that it expects FERC to impose in connection with hydroelectric plant operating licenses. PG&E contends that these expenses are necessary for maintaining the value of its hydroelectric assets and are therefore reasonable. PG&E notes that FERC can order it to decommission facilities if FERC licenses are not maintained, resulting in potentially costly watershed restoration costs. Relicensing costs are a lower-cost alternative to decommissioning, according to PG&E.

Of the forecast amount, $10.935 million is directly tied to Final Environmental Assessments or Draft Environmental Assessments. The remaining $175,000 reflects PG&E's input to the FERC's Assessment for New License. The forecast expenses apply to five hydroelectric projects for which relicensing proceedings are underway.

ORA, Enron, and Weil oppose PG&E's proposal for license condition costs. ORA bases its opposition on its contention that PG&E should not invest any more money in these facilities because it plans to divest or otherwise dispose of all of its hydroelectric plants. Enron proposes that the expenses be capitalized consistent with the Commission's treatment of FERC licensing costs in D.92-12-057. Enron believes that under PG&E's approach, PG&E could receive funding for these costs even before the licenses are issued. This could result in a windfall for PG&E. Weil expands on this timing issue, and also contests the level of expenses forecast by PG&E. Among other things, Weil notes that the forecasts reflect FERC staff estimates of project license condition costs that have not been approved by FERC in a final decision.

PG&E responds that if it does not perform these license condition activities, it risks incurring expensive decommissioning costs, or, if a new license is granted to another party, loss of a low-cost source of generation and reimbursement at a highly depreciated book value rather than market value. PG&E contends that ratepayers will benefit from its obtaining the highest market value for these facilities, as the profits will be used to offset ratepayers' CTC obligations. PG&E also contends that it has provided ample justification for the forecast amount, including 180 pages of supporting documentation.

Discussion

The disputes center on timing, i.e., when the expenses will be incurred, the need for such expenses in view of PG&E's plans for divestiture or other disposition of the assets, and the reliability of cost estimates presented by PG&E.

PG&E will not incur license condition expenses for a project until the license for that project is issued and the final conditions are in effect. Thus, PG&E's forecast for test year 1999 implicitly assumes that FERC will have granted licenses for each of the five projects at issue by the end of 1998. The evidence indicates this is an unrealistic assumption. For four of the five projects, the licenses expired during the 1975 to 1989 time frame, and PG&E has been operating the plants under annual licenses since their expiration dates. PG&E witness Bosscawen was not able to point to anything more substantive than discussions with PG&E personnel who work on FERC licensing to support his contention that the license conditions will be in effect in 1999. We therefore conclude that PG&E has not demonstrated that each of the five licenses and associated conditions will be in effect for the entire test year. We note that PG&E did not include evidence of the issuance of any of these licenses in its December 4, 1998 update testimony, despite a suggestion by Weil in his opening brief that PG&E do so. While not by itself conclusive, this reinforces our doubts about the reasonableness of PG&E's assumption.

There is reason to doubt the reliability of PG&E's forecast amount as well. PG&E has been in negotiations with FERC regarding license conditions for several years. In addition, it appears that PG&E generally has a number of years to fulfill the conditions. Moreover, while FERC may typically approve its staff's analyses, the estimates still have not been finalized. Thus, it is particularly puzzling that PG&E indicated license condition expenditures of $273,000 in 1997, $870,000 in 1998, and $11.11 million in 1999. PG&E has not shown why it is reasonable to approve such a large increase for 1999.

However, even though PG&E has not justified its forecast, it is probable that PG&E will incur some expenses for license conditions in the test year. We find that it is reasonable to include some level of license condition costs in the test year forecast. Moreover, we are not inclined to deny these expenses on the basis of PG&E's plans for divestiture of its hydroelectric assets. Until such divestiture or other disposition of the hydroelectric assets is final, it is reasonable and prudent for PG&E to take action to comply with any conditions imposed by FERC. Accordingly, we authorize PG&E to reflect one-half of its forecast of $11.11 million in its revenue requirement. This is an admittedly arbitrary judgment, but it is no more arbitrary than assuming that all of the annualized expenses estimated by FERC staff will actually be incurred by PG&E in the test year. If anything, it is a liberal allowance in light of the uncertainties and tenuous justification of the expenses forecast by PG&E for the Rock Creek-Cresta project, which accounts for a large share of the total forecast. Based on the foregoing, PG&E's forecast for hydroelectric license condition costs should be reduced by $5.555 million.

We find that our policy for capitalizing FERC license costs should not be expanded to expenses incurred for FERC license condition costs as proposed by Enron. Pursuant to the Uniform System of Accounts, PG&E has already reflected license condition costs as capital costs and expenses in this application.

7.2.1.4.4 Non-Routine Expenses (Accounts 544, 545)

Due to the advancing age of its hydroelectric system, PG&E forecasts additional non-routine maintenance expenses not identified in previous GRCs. PG&E forecasts expenses of $375,000 (Account 544) and $246,000 (Account 545) for non-routine maintenance. In work papers and rebuttal testimony, PG&E identified five specific projects included in Account 544 and three projects included in Account 545. Examples of these projects are generator bearing repairs and fish valve repairs.

ORA and Enron oppose increases in authorized maintenance expenses to reflect these expenses. Essentially, they contend that PG&E should not spend more money on these facilities in view of its plans to divest or otherwise dispose of them. We are persuaded that it is reasonable and prudent to reflect a forecast of ongoing maintenance requirements for as long as PG&E owns and operates these assets. We therefore approve PG&E's forecast for non-routine maintenance of hydroelectric facilities.

7.2.1.4.5 Storm Damage Insurance Recovery

PG&E incurred severe storm damage to its hydroelectric facilities during the winter of 1996-1997. When it filed this application, PG&E had not determined the level of insurance proceeds it would receive for recovery of storm damage expenses. PG&E therefore assumed no insurance recovery in forecasting test year expenses.

Weil believes that PG&E should be ordered to credit the appropriate expense and capital accounts in the event that it realizes insurance proceeds. However, PG&E's testimony shows that it expected to complete repairs in 1998, and that its forecast for 1999 does not reflect storm damage repair expenses. Moreover, the cost of storm restoration and repair, as well as the associated insurance proceeds, will be considered in a Catastrophic Events Memorandum Account (CEMA) filing. We need not resolve issues of compliance with Commission policy regarding insurance recovery and CEMA in this GRC.

7.2.2 Transmission

Although PG&E's transmission revenue requirement is subject to FERC jurisdiction, PG&E presented its forecast in this GRC to permit appropriate cost allocation. As shown in the comparison exhibit, PG&E forecasts total transmission O&M expenses of $94.126 million, while ORA's forecast is $88.461 million.

PG&E installed what it terms a mobile synchronous condenser at its FMC Substation to support transmission voltage in the San Jose area. PG&E will incur lease expenses of $3 million per year for this equipment through September 2001. The temporary support provided by the unit will be replaced by the Northeast San Jose Transmission Relief Project at that time, assuming we approve PG&E's application. PG&E states that the unit allows for reliable operation at this time.

PG&E and ORA dispute whether PG&E properly classified this expense as Transmission Voltage Support. ORA contends that the unit is a generator, and that the associated expense should be classified as a generation expense. ORA believes that booking a fixed generation expense as transmission would undermine the functional unbundling requirements of the Commission's restructuring policy decision, D.95-12-063, as modified by D.96-01-009. PG&E asserts that even though it has bid output from the unit as ancillary services into the ISO, the primary function of the unit continues to be emergency transmission voltage support.

In this GRC, we determine the classification of PG&E's FMC unit for purposes of allocation only. Our determination is not binding on FERC. PG&E witness Burnham confirmed that the FMC unit is a "Twin Pac Electric Generating Plant." We are persuaded that the unit adds generating capacity and is properly classified as a generating plant. We therefore adopt as reasonable ORA's recommended classification of this equipment as generation.

7.2.3 Distribution

7.2.3.1 Introduction

The following table summarizes the test year forecasts for total electric distribution system O&M expenses recommended by PG&E, ORA, Enron, and Weil. These parties advanced total operating account and total maintenance account forecasts (except that Weil supports ORA's forecast for operations expense without presenting an independent forecast).

Electric Distribution O&M Forecasts
(000's omitted, 1996 Dollars)

	PG&E	ORA	Enron	Weil
Operating Account Totals	128,833	122,218	120,762	122,218
Maintenance Account Totals	260,487	166,393	159,627	161,818
Total O&M	389,321	288,611	280,389	284,036

Other parties addressed distribution O&M expenses as well. CFBF recommends that PG&E's requested distribution expenses be reduced by $171.6 million. TURN generally concurs with ORA's recommendation for

Account 593 (maintenance of overhead lines) but recommends an adjustment pertaining to the pole test-and-treat program to reflect cost sharing with telecommunications utilities. In the event PG&E's proposed level of spending on tree trimming is adopted, TURN recommends a one-way balancing account for tree trimming expenses. TURN recommends that PG&E's forecast for underground lines operations (Account 584) be reduced by $947,667. Finally, TURN recommends changes to PG&E's Conservation Voltage Regulation (CVR) program. CAL-SLA does not present an independent recommendation, but it is concerned with what it finds to be a lack of support for PG&E's forecasts for Accounts 585 and 596.

For operating expenses, the $6.615 million difference between PG&E and ORA is attributable to expenditures and savings associated with information technology (IT) projects. These projects are addressed in Section 9.6 of this decision.

In contrast to the forecasts of operations expenses, the estimates for electric distribution system maintenance expenses differ greatly and are highly contested. ORA's maintenance forecast is $94.1 million below PG&E's, while Weil's and Enron's forecasts are $98.7 million and $100.9 million, respectively, below PG&E's.

PG&E originally forecast total maintenance expense of $284.3 million, reduced the forecast to $262.3 million in its March Update, and further reduced it to $260.5 million as shown in the comparison exhibit. Even with the reduction of $24 million from its original request in this GRC, PG&E is requesting a dramatic increase over the $120 million forecast adopted in the 1996 GRC. Its forecast is more than double the amount previously found reasonable by the Commission.

The largest source of the differences is the parties' divergent estimates of the funds needed for maintenance of overhead lines, i.e., expenses recorded in

Account 593. Parties dispute the forecast expenses for vegetation management, and particularly for tree trimming. Of PG&E's recommended total maintenance budget of $260.5 million, $182.6 million is for Account 593. Of ORA's recommended total maintenance budget of $166.4 million, $110.5 million is for Account 593. Of Enron's recommended total maintenance budget of $159.6 million, $106.4 million is for Account 593.

Before we consider O&M forecasts on an account-by-account basis, we first address the history and significance of PG&E's past maintenance practices, forecasts for vegetation management, broad issues pertaining to forecasting methodology, and TURN's recommendations for PG&E's CVR program. In all, the parties devoted nearly 240 pages of their briefs and reply briefs to electric distribution O&M issues. We do not attempt to describe herein each and every position and argument of the parties, although we describe in considerable detail ORA's position on PG&E's past maintenance practices.

7.2.3.2 Past Maintenance Practices

ORA, joined by other parties, contends that PG&E's electrical distribution system maintenance was either deficient or unreasonably deferred in the years preceding the 1996 base year upon which PG&E developed its test year forecast. ORA further asserts that this deficient or deferred maintenance has resulted in higher overall costs, which PG&E now inappropriately seeks to recover through test year rates. Because of the magnitude of the increases sought by PG&E for maintenance, as well as its concerns about PG&E's past maintenance practices, ORA retained the services of the engineering consulting firm MHB Technical Associates (MHB) to review PG&E's past maintenance practices and its proposed maintenance budget in this GRC. References to ORA herein include MHB where applicable.

ORA begins its analysis by noting that between 1987 and 1994, PG&E underspent the amounts authorized for maintenance by a total of $495 million. During the same period, PG&E underspent the amount authorized for Account 593 by $90 million. This underspending, ORA maintains, occurred even as the authorized level for total maintenance costs was itself decreasing. The total authorized amount for maintenance declined from nearly $247 million in 1987 to less than $165 million in 1993. The amount authorized for Account 593 decreased from $119 million to $81 million during this same period.

The pattern of underspending on maintenance began to change in 1995, when PG&E spent approximately $16 million more than the authorized amount. (ORA contends that most of the additional spending in 1995, about $14.7 million, was attributable to one-time activities associated with 1995 storm damage.) The pattern then changed dramatically in 1996. Even though the 1996 GRC decision lowered the total authorized maintenance level from $164.5 million to $119.6 million, largely at PG&E's request, recorded expenditures in that year were $230.6 million, nearly double the authorized amount. Almost $160 million of this spending was attributable to Account 593.

ORA describes and relies upon extensive evidence, summarized below, concerning PG&E's past maintenance practices. ORA asserts that this evidence shows that PG&E's maintenance practices were deficient for a number of years. ORA further contends that the accelerated maintenance activities and higher expenditures recorded in the 1996 base year are largely attributable to PG&E "playing catch-up," i.e., spending more on maintenance as a direct result of the earlier deficient or deferred maintenance practices. Much of this evidence is contained in consultant reports prepared for PG&E and in the analysis of those reports by ORA / MHB witness Minor.

Bain Report

Bain and Company (Bain), a consulting firm retained by PG&E, released a report in June 1993 on certain aspects of PG&E's electrical system maintenance practices. Among the more significant findings of the Bain report were the following:

> <u>Overall</u>
> Service reliability spending per customer and per line mile had fallen between 12-14% since 1989.
>
> Due to declining budgets, some divisions were scaling back on the amount of routine maintenance performed.
>
> Historically, divisions had underspent their budgets. This may have been caused by a desire to ensure meeting Performance Incentive Program goals.
>
> Even though outages per customer were decreasing, total system outages were growing at nearly 6% annually while line growth had climbed only 1% per year).
>
> Future investments needed to be made in preventive programs and not primarily in emergency repair.
>
> <u>Wood Poles</u>
> Pole testing and treatment has a large economic impact and can extend the average service life over 20 years.
>
> Pole maintenance funding had been declining at 14% per year since 1984.
>
> Between 1984 and 1987, pole testing and treating fell to a quarter of its previous levels. It had essentially stopped as a routine practice at PG&E.
>
> An immediate test-and-treat program would extend the life of approximately half of the installed base, and in the future ongoing cycles could affect all poles in place.

Although ongoing pole test and treatment provides "enormous benefit" to both customers and shareholders, current incentives, including the budgeting process, the imposed budget cuts, and the Performance Incentive Program, penalize the divisions for undertaking such programs.

Because poles were reaching the end of their useful lives faster than PG&E's routine programs were replacing them, Bain concluded that "the number of poles expiring grows as does the number of deferred pole replacements."

Of PG&E's 25 divisions, 22 cited pole replacement programs as an area where greater resources may be warranted and 14 divisions cited this as a critical area.

PG&E had an opportunity to save $40 million (in 1992 dollars) because pole asset service lives would be prolonged through investment in testing and treating and by implementing best pole replacement practices.

<u>Tree Trimming</u>
PG&E's tree trimming expenditures fell between 1987 and 1989, and by 1993 had climbed back to 1987 levels.

PG&E's then-current practices yielded sub-optimal results: program spending was increasing, reaching an all time high in 1993; tree caused outages were the second largest cause of outages and were growing at over 8% per year; non-routine trimming, which was over 30% more expensive than scheduled trimming, was increasing relative to scheduled trimming; and much of PG&E's system had yet to reach a regular grid cut cycle.

Of PG&E's 25 divisions, 20 cited tree trimming programs as areas where greater resources may be warranted, 12 cited the level of non-routine tree trimming as a concern, and 20 viewed this as a critical area.

PG&E could reduce tree trimming spending by up to $10 million (in 1992 dollars) while improving reliability, by moving to a centralized program and adopting best identified peer practices.

> <u>Overhead Equipment (and Substation Equipment)</u>
> Then-current spending patterns for overhead equipment were sub-optimal. Although spending levels were falling, over 50% of spending was reactive / emergency spending.
>
> The then-current spending mix for substation equipment was sub-optimal. Reactive spending had outpaced preventive spending by 15-20% since 1989.
>
> Of PG&E's 25 divisions, 14 were concerned with overall overhead deterioration and thought greater resources may be warranted, and 14 divisions cited this as a critical area.

The Bain report noted that while PG&E's reliability continued to be excellent, there were areas of potential concern, including the fact that PG&E did not have or use appropriate data to fully understand the extent or significance of the outages customers were experiencing. The report further noted that:

> Service reliability investments appeared to have not been optimally allocated or expended. Reactive spending was increasing relative to preventive spending, some maintenance program expenses had declined as overall expenditures have been squeezed, and divisions had historically underspent their budgets.
>
> Assessment of service reliability issues focused attention on the questionable condition of several major asset classes: wood poles, tree trimming, and overhead equipment.

PG&E's Practices Following the Bain Report

Despite the Bain report's concern over the impact of the Performance Incentive Program on spending levels, ORA asserts that PG&E management took no action to alter the incentive to continually reduce maintenance expenditures. ORA claims that this is evidenced by an audit by Arthur Andersen (discussed below). ORA also asserts that even after the Bain Report was issued, PG&E

continued to spend less than the authorized amount on maintenance activities, by $24.757 million and $36.962 million in 1993 and 1994, respectively.

In its 1996 test year GRC, which was filed in December 1994, PG&E requested and received a further reduction in both its overall maintenance budget and its tree trimming budget. However, in adopting a reduced budget for tree trimming the Commission stated that:

> "We adopt PG&E's estimate for tree trimming in the test year with PG&E's assurances that the lower budget for tree trimming reflects cost savings rather than a reduced effort in tree trimming." (D.95-12-055, 63 CPUC2d 570, 604.)

Additional Analyses of PG&E's Practices Following the 1995 Storms

PG&E's service territory was hit with severe winter storms in January, March, and December 1995. More than one million customer interruptions occurred during each of the January and March storms. Approximately two million interruptions occurred during the December storm. Following the January and March storms, PG&E retained the services of two outside consultants, Arthur Andersen and Black & Veatch, to evaluate PG&E's maintenance practices and procedures. The express purpose of the Arthur Andersen audit was to review the adequacy of PG&E's preventative processes and practices. The Black & Veatch review focused on the policies, standards and guidelines that directed the preventative maintenance activities. The findings of these consultants, summarized below, were issued in August 1995.

The Arthur Andersen review found significant problems with PG&E's preventative maintenance practices, including the following:

> The Performance Incentive Program encouraged employees to spend less than the budgeted amount, increasing the risk of

> deferring or discontinuing gas and electric preventative maintenance programs.
>
> Preventative maintenance programs were budget driven, not service-reliability driven, which leads to deferring or eliminating programs.
>
> There was a "cut cost at any cost or we will find someone who will" philosophy, which adversely affected upward communication within the company.
>
> Preventative maintenance programs appeared to have been insufficiently funded.
>
> The link between the planning concepts of service reliability and the funding of preventative maintenance programs was not evident in either the planning phase or the resource allocation phase.
>
> Reductions in the budget each year failed to demonstrate an understanding of the potential degradation in service quality which results in underfunding future preventative maintenance programs.
>
> Generally, Divisions were not complying with PG&E preventative maintenance requirements.
>
> Some districts had stopped performing preventative maintenance and were managing maintenance in a 100% reactive mode.
>
> Inspection, maintenance, and repair of both overhead and underground electrical distribution facilities was not being performed consistent with PG&E standards due to a lack of accountability, lack of performance measures, and lack of data regarding the costs of such efforts.

ORA points out that two years after the Bain Report, Arthur Andersen continued to find problems with PG&E's tree-trimming effort. ORA / MHB witness Minor testified that:

> "[W]hen Arthur Andersen reviewed the [vegetation management] program two years later, they found that 'a substantial percentage' of the vegetation management efforts continued to be spent on more

> expensive non-routine trimming, that despite the large budget, tree-related outages continued to be a primary cause of unplanned outages and that about half of those were believed to be avoidable, and that the Division Managers who had the responsibility for system reliability had 'little or no' control over this program, which heavily impacted system reliability. The report also noted that some divisions had expressed concern that this program was 'not functioning adequately to reduce tree related outages.' One of the implied weaknesses in the newly centralized program was that no one really knew the number of trees that needed to be trimmed each year by location, and thus that resources were not being assigned appropriately." (Exhibit 81, pp. 36-37.)

ORA further cites Arthur Andersen's finding that as a result of inadequate tracking, the actual condition of the electrical distribution system was not known to PG&E at either the division or overall company level. ORA found this deficiency to be of particular concern, because large sums of money are often required to regain the knowledge essential to maintaining a safe and reliable distribution system.

The Black & Veatch review of PG&E's policies, standards and guidelines was generally more favorable to PG&E. For example, Black & Veatch found that PG&E's tree-trimming program, which at the time was based on a 3 ½-year trim cycle, was "best-in-class." However, ORA notes, that finding concerned the program itself and not whether it was actually being implemented. Moreover, ORA observes, Black & Veatch also found a number of problems, including the following:

> PG&E's preventative maintenance documents varied significantly in technical depth, ranging from insufficient to overly detailed.
>
> General organization was good, but the documents were scattered among other materials rather than grouped into an overall maintenance document.

> A wide variety of forms, lists, and secondarily referenced materials appear to make it difficult to manage and control the information over long periods and complicate detailed analysis.
>
> Significant responsibility for detailed implementation has been delegated to the division level, although only 50% of the divisions appear to have any documented maintenance plans.

Black & Veatch recommended that PG&E develop a definitive set of policies, standards, guidelines and implementation documents, and that PG&E develop a structured plan with a practical budget and an achievable schedule for its preventative maintenance program. Black & Veatch concluded that PG&E should conduct a company-wide audit of its system to determine its condition. To the extent that widespread repair or maintenance was required, Black & Veatch recommended an implementation period of no more than five years.

In D.95-09-073 dated September 7, 1995, issued after hearings on the damage resulting from the January and March 1995 storms, the Commission found that employee reductions, extended maintenance cycles, and an inadequate customer service telephone system affected the efficacy of PG&E's response to the storms. (D.95-09-073, 61 CPUC2d 493, 503.) The Commission also found that the record in that proceeding did not support a finding that PG&E's response to the storm was unreasonable or that the condition or management of its system prior to the storms was unreasonable (*Id.*), but explained this finding by stating in the body of the decision:

> "Based on the record in this proceeding, we cannot find that PG&E was unreasonable. This is not to say that PG&E's customer services, maintenance programs, or employee reductions were or are reasonable. Rather, the record does not permit us to reach the conclusion that PG&E failed to fulfill its obligation to provide reasonable levels of service and safety to its customers." (*Id.*, p. 500.)

PG&E's Responses to the Consultant Reports

ORA states that PG&E generally accepted the findings of Bain, Arthur Andersen, and Black and Veatch as factually accurate and consistent with internal audits. ORA concludes that PG&E responded to the findings and recommendations contained in these audits by embarking upon a large scale and costly remediation effort to recover from the effects of past deferred and / or deficient maintenance practices. ORA further concludes that the cost of this effort is included in 1996 recorded figures.

In response to PG&E's positions that it did not defer maintenance, that there are no costs attributable to deferred maintenance in 1996 recorded figures, and that there are no costs attributable to deferred maintenance in its test year forecast, ORA counters that:

> "[A]ll three reports noted that the preventive maintenance activities were driven by budgets rather than by system needs. Bain and Arthur Andersen noted that divisions had incentives to cut back on preventive maintenance in favor of reactive maintenance practices, and that as a result many had done so. Indeed, Arthur Andersen concluded that some divisions were relying nearly exclusively on reactive maintenance practices. The result of making such a change is that, in the short term, maintenance costs might go down. However, in the long term, overall system costs will go up as early equipment replacement and system failures become more common." (Exhibit 81, pp. 41-42.)

ORA finds there are potentially serious consequences from deferring maintenance of PG&E's electric distribution system. ORA points to testimony showing that prudent preventative maintenance expenditures (1) extend the life of many system components, reducing the frequency and costs associated with having to replace parts of the system; and (2) can reduce the number and severity of outages and emergency events, resulting in more reliable service to customers, a safer system, and a reduction in the number of people and resources necessary to recover from such outages and emergencies.

As further evidentiary support for its position that PG&E was still spending more on maintenance in 1996 than it would have needed to if earlier practices had been adequate, ORA refers to the accelerated tree trimming efforts in 1995 and 1996. PG&E acknowledges these efforts, which it claims were necessary to bring its system into compliance with the Public Resource Code (PRC) provisions and General Order (GO) 95. Spending on tree trimming increased from approximately $50 million annually from 1987 to 1994 to $65.3 million in 1995 and again to $105 million in 1996. ORA rejects PG&E's explanation that this increased spending was due to the accelerated growth rate of the trees following wet winters, noting that the increased spending followed the findings of Bain, Arthur Andersen, and Black & Veatch that tree trimming was being managed ineffectively or inefficiently. Based on the foregoing and on (1) the findings that non-routine activities were taking up an increasing portion of the budget and routine activities were not keeping up with demand; (2) a partial inventory in the North Valley and Sierra Divisions in August 1995 indicating that there were 95,000 "burners" and another 50,000 trees within four feet of power lines, (3) a more complete inventory in November 1995 indicating over 325,000 "tree line contacts" in areas governed by both PRC provisions and GO 95, ORA attributes the increased spending to

> "years of mismanagement in which funds provided by ratepayers for tree trimming activities were diverted to other purposes resulting in an ever more inefficient tree-trimming operation." (ORA Opening Brief, p. 96.)

ORA concludes that:

> "The costs associated with this mismanagement cannot be quantified but are clearly embedded in the recorded 1996 figures which PG&E uses as a base year." (*Id.*)

Discussion

Under traditional rate of return regulation, utilities are given an incentive to reduce expenditures through increased productivity, with the understanding that these savings accrue to shareholders between rate cases and are passed on to ratepayers in the next GRC. (*Re General Telephone of California,* (1985) D.85-03-042, 17 CPUC2d 246, 254.) As ORA acknowledges, utilities often spend more than the amounts authorized by the Commission for a given activity in one period and less in another. PG&E notes that it overspent its authorized electric distribution O&M budget by a total of $118 million between 1980 and 1986, and that it has again been spending more than authorized amounts for maintenance since 1995.

Thus, there should be nothing particularly surprising or alarming in simply finding that a utility has spent less on an activity in any year (or other limited period) than was authorized by the Commission for that year. In addition, irrespective of authorized expenditures, decreasing recorded expenditures on maintenance are not necessarily evidence of problems. Indeed, such underspending may represent a positive development for ratepayers and shareholders alike if it is the product of efficiency gains, improved knowledge about the need to perform various activities, and as long as necessary and prudent activities are timely performed. On the other hand, a utility's pattern of consistently spending less than authorized amounts by substantial margins, and over an extended period, may be a warning sign that ratepayers are providing funding for activities that should have been performed, but which in fact have not, but which in fact have not been or that forecasting methods suffer from a systematic error.

Using data from Exhibit 81 (pp. 13 and 15), the following table shows the amounts authorized for PG&E's total electric distribution maintenance and the recorded spending amounts for the years 1987 through 1996. The adopted amounts for 1987, 1990, 1993, and 1996 reflect test year adopted amounts. Those for 1988, 1989, 1991, 1992, 1994, and 1995 reflect attrition adjustments.

Electric Distribution Maintenance Expenses
(000's omitted, 1996 Dollars)

	Adopted	Recorded
1987	246,630	170,738
1988	249,760	154,049
1989	246,953	134,676
1990	186,686	139,354
1991	185,472	137,601
1992	185,183	131,189
1993	163,452	138,695
1994	164,454	127,492
1995	164,530	180,900
1996	119,579	230,594

We observe that the underspending shown in the foregoing table does not, by itself, demonstrate unreasonable practices. We also note that ratepayers benefited (monetarily, if not otherwise) from reductions in authorized expenditures over this period. Nevertheless, the fact that for almost a decade, throughout a series of GRC cycles, PG&E consistently underspent ever-decreasing budgets and then increased spending dramatically in 1995 and 1996, is cause for concern and further investigation.

We emphasize our earlier statement: the primary purpose of this and any GRC is to determine a reasonable level of revenue during the prospective test period needed to provide adequate utility service. Even if PG&E's past maintenance practices were found to be inadequate and unreasonable, it is not our purpose in this proceeding to penalize PG&E for such practices. However, we will not allow unreasonable expenses for prospective ratemaking purposes. While GRCs are forward looking, a utility's past maintenance practices may be relevant to the analysis of a test year forecast for maintenance expense. Ratepayers would effectively be charged for such practices if it is shown that (1) a utility engaged in deficient practices or deferred maintenance unreasonably, (2) such deficient or unreasonably deferred maintenance resulted in the utility's spending more money on maintenance in a subsequent period than it would have needed to spend if its prior practices had been reasonable, and (3) total maintenance expenditures for that subsequent time period were used in developing a test year forecast. It would be unjust and unreasonable to make ratepayers responsible for the amount of expenses attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past, <u>but not performed by the utility</u>.

We find that the combined impact of the Bain, Arthur Anderson, and Black and Veatch studies, along with analyses by ORA based on these studies and on additional documentation obtained through discovery, is compelling. ORA has presented convincing evidence that PG&E's electric distribution system maintenance practices were inadequate in several important respects for a period of several years prior to 1995. Preventative maintenance spending was budget-driven rather than system needs-driven; managers were given incentives to cut costs and spend less than budgeted amounts for preventative maintenance without giving (or being able to give) due regard to the effects of doing so on safety, reliability, or future costs. PG&E was forgoing cost-effective spending on preventative maintenance activities such as pole testing and treating, and was devoting significant proportions of its spending on reactive and emergency activities even as spending on routine maintenance was declining. PG&E lacked accountability mechanisms, performance measures, and data regarding inspection, maintenance, and repair activities; lacked knowledge of the actual condition of the distribution system; and failed to effectively delegate maintenance planning responsibility to the division level with appropriate accountability. PG&E's preventative maintenance programs were not meeting the company's own standards, and PG&E apparently failed to timely and appropriately respond to certain recommendations in the Bain report.

In short, PG&E did not plan and manage electric distribution system maintenance activities as effectively as it could and should have during the late 1980s and early to mid-1990s, claims regarding the influence of weather, the economy, and regulatory pronouncements notwithstanding. We make these findings based on the extensive record in this proceeding, while recognizing that we declined to make similar general findings of inadequate maintenance practices in D.95-09-073, in the 1995 storm damage proceeding, based on the record and the purpose of that proceeding.[12] The evidence also shows that PG&E began correcting this situation at about the time of the storms of early 1995.

ORA has demonstrated that deferred and deficient maintenance practices can have the effect of requiring increased expenditures in the future even though they may save money in the short run. Moreover, for PG&E, this "future" period undoubtedly included 1996, the very year that PG&E's recorded maintenance expenditures rose to more than $230 million, or about 93% more than the

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[12] While the record reviewed in D.95-09-073 did not support a finding that the condition or management of PG&E's system prior to the early 1995 storms were unreasonable, we did find that employee reductions, extended maintenance cycles, and an inadequate customer service telephone system affected the efficacy of PG&E's response to the storms. (D.95-09-073, 61 CPUC2d 493, 503.)

authorized amount for that year and about 81% more than the recorded expenditures of two years earlier. Based on the record before us, we cannot conclude that the physical condition of PG&E's electrical distribution system at the beginning of 1996 and the readiness of PG&E's management and work force to perform maintenance activities were exactly the same as they would have been had PG&E spent more on maintenance, and spent if more effectively, in the preceding years. Further, we cannot conclude that none of the increased level of spending in 1996 is attributable to past inadequate maintenance by PG&E. We note that PG&E distribution expense witness Carruthers, does not take the position that recorded expenses for 1996 are not inflated as a result of deferred or deficient maintenance practices. We cannot conclude with any confidence that 1996 activity levels are wholly representative or normal for purposes of estimating test year 1999 activities.

More problematic is determining the extent to which PG&E's 1996 recorded spending levels were impacted by these past inadequate practices. Here, ORA's case relies on sound theory but less on hard fact. While the record before us is quite extensive, it provides insufficient basis for reliable measurements of the dollar impact of PG&E's past maintenance practices. ORA contends that remediation efforts were "large scale and costly," and that the increases in maintenance spending are largely attributable to PG&E playing catch-up. However, ORA also acknowledges that costs attributable to deferred or deficient maintenance practices simply cannot be quantified. For perspective, we observe that PG&E's forecast of O&M expenses excluding vegetation management costs is $253.3 million, which compares to a four-year average (1993-96) of $228.3 million. PG&E witness Carruthers contends that the difference of $25 million, $10.8 million of which is accounted for by IT projects, is not indicative of a forecast reflecting an attempt to make up for $500 million of deferred maintenance. We agree, although we do not believe that ORA claims that the increment of 1996 maintenance spending associated with deferred maintenance approaches anything close to $500 million. On the other hand, an increase of more than $14 million for the non-vegetation management component of O&M costs ($25 million less $10.8 million for IT projects) is not trivial, given the inclusion of recorded 1996 with its extraordinary expenditures.

The problem is that PG&E's reduced maintenance spending in the late 1980's and early 1990's cannot be attributed solely to greater efficiencies, economic and weather conditions, and the regulatory climate. To the contrary, it is apparent that PG&E's reduced level of spending during that period, at least in significant part, was associated with performance of fewer maintenance activities than PG&E should have performed.[13]

Since PG&E had gone too far in cutting back on maintenance expenditures, it follows that increased spending in 1996 represents, in part, a return to normalcy. Even taking into account spending variations that would be associated with efficiency and exogenous conditions like weather and the economy, we find that PG&E almost certainly should have been spending more than it was actually spending on distribution maintenance in the years before 1995. In other words, PG&E did not merely underspend prospectively authorized amounts, it spent less than reasonable and prudent amounts for maintenance.

Accordingly, we would expect some increased level of spending in 1996 as an appropriate, reasonable, and necessary action by PG&E in response to the

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13 The proposition that PG&E had gone too far in cutting back on expenditures in the years before 1995 is consistent with PG&E's conviction on more than 700 counts of criminal negligence associated with the 1994 Rough and Ready fire in Nevada County.

Bain, Arthur Anderson and Black and Veatch reports, and in the wake of the 1995 storms and ensuing actions that we undertook. Combining this determination with our finding that a portion of PG&E's 1996 spending reflected remediation for past practices, we are left with two conclusions: (1) that an unquantified portion of PG&E's increased distribution maintenance spending in 1996 can be attributed to earlier deficient or deferred maintenance, for which ratepayers should not be responsible; and (2) that another unquantified portion of the increased spending can be seen as a reasonable and appropriate response by PG&E for which PG&E should be recompensed by ratepayers. As discussed earlier in Section 5, we also recognize that part of the 1996 recorded spending level is associated with less than optimal efficiency performance by PG&E. In the following sections we resolve the allocation of shareholder and ratepayer responsibility in 1999 for the increased maintenance expenditures by PG&E in 1996. Before doing so, we address a procedural issue raised by PG&E.

In supplemental hearings in the previous GRC docket, we reviewed PG&E's response to the December 1995 storm. Among other issues, parties were asked to address the adequacy of PG&E's plant maintenance and repair prior to the storm. On May 24, 1996, the Division of Ratepayer Advocates (DRA), ORA's predecessor organization, filed a report in which it found PG&E's transmission and distribution maintenance practices to be generally adequate. PG&E states that ORA (but obviously meaning DRA) had access to the Black & Veatch and Arthur Anderson studies when it made that finding.

In view of this earlier finding by DRA, PG&E claims in its opening brief (at p. 78) that it is "disingenous and irresponsible" for ORA to claim in this GRC that PG&E's prior maintenance practices were deficient. PG&E also claims that "[f]or ORA to present diametrically opposed sworn testimony on the same issue in two proceedings before the Commission is misleading to the Commission, and should not be tolerated." (*Id.*) PG&E contends that "ORA is estopped under accepted principles of judicial estoppel from asserting in this proceeding

> that PG&E's maintenance practices were deficient when [it] made an opposite assertion on the same issue in a prior proceeding involving the same practices." (*Id.*)

ORA responds that the time period referenced in the earlier DRA conclusion (that PG&E's maintenance practices were generally adequate) was the period following issuance of the Arthur Anderson and Black and Veatch studies, when PG&E had already begun implementing the recommendations therein. Accordingly, there appears to be no inconsistency between the prior DRA position and the current ORA position.

Even if there were such an inconsistency, we would not reject ORA's current position on that basis alone. ORA and this Commission are free to reevaluate PG&E's past maintenance based on facts and analysis now available to us for the purpose of estimating 1999 test year levels of activity and expenditure. Just as we do not find that PG&E has mislead the Commission by providing a showing in support of a much higher tree trimming budget than it presented in the last GRC (even though PG&E provided us with assurances in that GRC regarding the adequacy of its tree trimming budget), we disregard PG&E's assertion that ORA has mislead the Commission.[14]

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[14] There are other examples of PG&E's having taken different positions on an issue. In its 1996 GRC, PG&E took the position that it could comply with a four foot tree clearance requirement which applied in most of its service territory with a 3.5 year trim cycle. In this GRC, PG&E takes the position that a 3.5 year cycle (or any other cycle-based trim program) is inadequate to meet an 18-inch clearance requirement. Even within this GRC, PG&E has taken varying positions. In its original testimony,

Footnote continued on next page

We reject the contention that the equitable doctrine of estoppel prevents ORA from discovering new evidence or further analyzing existing evidence regarding PG&E's past maintenance practices in this GRC. This would be a complete misapplication of the equitable doctrine of estoppal. To adopt it would undercut our ability to establish a solid evidentiary basis on which to base our determinations regarding the reasonableness of prospective rates and practices. Prior statements and positions such as those taken by ORA in its 1996 report may affect the weight which we choose to give testimony in the current case that may reflect a re-evaluation, but those prior statements cannot be the basis either for precluding the current testimony or precluding a decision based in part upon it.

We take quite seriously legitimate, substantiated claims of a party's having mislead the Commission. For this reason, we insist that parties refrain from casually making such claims as PG&E has done here, in advancing argument on a contested issue. Such assertions contribute to maintaining a noxious atmosphere that undercut our efforts to establish reasonable rates on the basis of sound information. In the future, if a party has concluded and is willing to allege that another party has mislead the Commission in contravention of the Rules of Practice and Procedure, it should do so under oath in an appropriate pleading dedicated to that purpose.

PG&E asserts that "all tree trimming expenditure projections assume normal weather patterns." (Exhibit 6, pp. 7-8.) In its rebuttal testimony, PG&E estimates the need for an additional 200,000 tree trims in 1999 to accommodate the excessive amount of rain that occurred during the 1997-98 winter season. (Exhibit 27, pp. 6-29.) (PG&E witness Carruthers acknowledges this contradiction.)

7.2.3.3 Vegetation Management

PG&E and ORA both presented analyses of Account 593 by separating vegetation management expenses and non-vegetation management expenses.

As shown in the following table, PG&E forecasts total vegetation management expenses of $137.8 million for the test year. By way of comparison, the amount authorized in the 1996 GRC was $41.6 million. As the table also shows, PG&E's 1999 vegetation management forecast consists of forecasts for tree trimming, vegetation clearing, and a tree removal / replacement project.[15]

PG&E's 1999 Vegetation Management Forecast
(000's omitted, 1996 Dollars)

Item	Amount
Tree Trim / Remove	$110,658
Vegetation Clearing	$ 6,795
Tree Removal Project	$ 20,384
Total 1999 Forecast	$137,837

ORA did not explicitly recommend a separate budget for vegetation management, although it presented several analyses and alternative calculations for purposes of analyzing Account 593 expenses and checking its primary recommendation. ORA's alternative analysis yielded a range of estimates from $61.5 to $67 million for tree trimming. Based on ORA's total recommendation for Account 593, PG&E calculated that ORA's implicit recommendation for vegetation management is approximately $65.3 million. PG&E also determined that this could be divided into a tree trimming budget of $63.7 million and a vegetation clearing budget of $1.5 million.

15 PG&E uses the terms "project" and "program" interchangeably to refer to certain non-routine tree removal and replacement activities which are discussed below.

Because of the importance of vegetation management expenses to the parties' forecasts for Account 593, as well as their overall distribution maintenance expenses forecasts, we find it is appropriate to consider development of a separate "bottom-up" forecast for this activity.

7.2.3.3.1 Tree Trimming

PG&E's tree trimming forecast is based on the estimated number of required trims and routine removals, using information from PG&E's new tree inventory, with adjustments to compensate for the above-average rainfall in 1997 and 1998, multiplied by the appropriate unit cost. ORA uses a somewhat similar bottom-up approach for its alternative analyses.

7.2.3.3.1.1 Number of Trims/Routine Removals

PG&E relies upon a new tree inventory database which it developed between 1995 and 1997. It contains detailed information on the number of trees in proximity to its 89,000 miles of overhead primary distribution lines (4 kV, 12 kV, and 21 kV circuits) and the species and growth rates of those trees. PG&E states that the purposes of developing this inventory were to determine the actual number of trees needing trimming or removal in its service territory and to create a planning tool to more efficiently and effectively manage tree trimming activities. PG&E asserts that it can now determine, with a high degree of accuracy, the number and frequency of trims and removals it must conduct annually to comply with applicable tree trimming requirements.

Through this new inventory, PG&E determined that it has nearly five million trees in proximity to primary distribution lines that require either trimming or removal. Specifically, in its original GRC testimony, PG&E indicated that 4.445 million trees in its service territory require systematic trimming. In its rebuttal testimony, PG&E indicated there are 4.832 million such trees. [16]

Given the current and anticipated growth rates of these trees, PG&E estimates that it must trim 1.887 million trees annually. (This is PG&E's latest estimate of record. In its original testimony, PG&E projected a "base annual tree trimming workload" of 1.678 million trims.) PG&E also estimates that it needs to trim more than 200,000 additional trees per year as a result of rainfall patterns in 1997 and 1998. It therefore estimates a need for a total of 2.1 million trims annually. In contrast, during the period 1987-1994, PG&E trimmed or removed an average of 845,000 trees per year based on an assumed or implicit four-year trim cycle (reduced to a 3.5-year cycle in 1993) and an assumed inventory of 3.5 million trees.

ORA estimates a trim and removal requirement of 1.242 million units annually. To develop this estimate, ORA used PG&E's historical average production value of 845,000 trims and routine removals per year for 1987-1994, and adjusted it to reflect the shift from a 4-year trim cycle to a 3.5-year trim cycle in 1993 as well as the increase in the number of trees from 3.5 to 4.5 million.

PG&E criticizes ORA's calculation because it relies on 1987-1994 data and ignores data in the new inventory. PG&E also faults ORA's calculation because, according to PG&E, trimming all of PG&E's system on a 3.5-year cycle (or any single system-wide cycle) is inappropriate for maintaining the required

16 During the course of this proceeding, ORA was often frustrated by PG&E's incomplete, changing, and inconsistent vegetation management data. ORA notes, for example, that PG&E's original application testimony did not include a tree trimming budget or unit cost data. Having spent considerable time grappling with the record on this issue, we now share ORA's frustration.

clearances throughout its service territory. Finally, PG&E claims that the adjustment for the number of trees is not representative of the estimated trim requirements for each tree.

Discussion

We start with the premise that the change in PG&E's tree trimming and routine tree removal activity, from an average rate of 845,000 units per year during the period 1987 to 1984 to 2.1 million units per year in 1999, is a major increase (149%) which warrants careful scrutiny for purposes of setting PG&E's rates in 1999 and beyond. In view of the potential revenue requirement impact of this increased activity, we are reminded once again that PG&E must demonstrate through clear and convincing evidence that this increase is justified.

PG&E places great confidence in the analyses allowed by its new tree inventory data base. In effect, this new tool is the primary, if not the sole basis, for the number of trims forecast by PG&E.[17] We find that this data base represents the potential for substantial improvements over PG&E's earlier vegetation management approaches. This is because it incorporates specific data regarding species and growth rates of trees in proximity to distribution lines, and should facilitate more effective management of tree trimming efforts. Given the different estimates of the number of subject trees that PG&E has used over the years, simply having a reliable count of subject trees will be a major

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17 In a data response to ORA, PG&E acknowledges that there are no incremental costs associated with the 18-inch clearance requirement adopted by the Commission in D.97-01-044 (other than initial compliance costs incurred in 1997 and 1998) relative to 1996 recorded, if not also authorized spending. In any event, there is no record evidence demonstrating that there are any ongoing incremental costs associated with the 18-inch requirement.

improvement for PG&E in its management of this important and expensive activity.[18] This new tool should allow more reliable and consistent counts in the future.

Nevertheless, our understanding of this tool is still evolving. The data base was, to some extent, a work-in-progress when PG&E prepared this application. PG&E witness Carruthers acknowledged that the inventory was not complete when he wrote his direct testimony. Moreover, PG&E witness Vannice, Executive Director of the Utility Arborist Association, does not know of any other investor-owned utility besides PG&E that has conducted such an inventory, which suggests that this is an untested if promising approach to utility tree trimming management.

In addition, we are unfamiliar with the methods used by the more than 100 qualified consultants with either a forestry or arborist background who assisted PG&E in developing its inventory. We recognize that they patrolled all of the company's overhead high-voltage lines, and, with hand-held computers, documented pertinent information for every tree requiring vegetation work for the next seven years. However, the record does not disclose the assumptions and criteria that went into the analysis. We do not know, for example, what would lead to the conclusion that a given tree in a given location requires trimming every six months rather than every year. We note that Carruthers was not familiar with how the consultants accounted for species and subspecies of trees, and he was not sure how many species are catalogued in the inventory.

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18 PG&E assumed there were 3.5 million trees during at least most of the 1987-1994 period, estimated there were 3.4 million trees in 1993, estimated there were 4.5 million trees in the 1996 GRC, estimated there were six to eight million trees in A.96-04-002, and presented counts of 4.445, 5.0, and 4.832 million trees in this GRC.

We also note that PG&E provides little or no explanation of the relationship of the inventory of faster-growing trees to its supplemental program to remove those trees, and how the fast growing component of the inventory will change over time as a result of the supplemental program. These are issues that, if explored, may assist us and PG&E in using this tool in the future.

There is no direct evidence that unreasonable or inappropriate assumptions or criteria were applied by PG&E's consultants in developing th tree inventory. Nevertheless, TURN suggests that there could have been incentives for those developing the inventory to err on the side of more frequent trims. It is clear that the potential consequences of underestimating the required number of trims are far more serious for PG&E than the potential consequences of overestimating the requirement. As long as it can recover the costs of more trims, there are no adverse consequences to PG&E of overtrimming. In contrast, given PG&E's history of problems associated with what were clearly inadequate tree trimming efforts in the past, PG&E had reason to apply very conservative, i.e., risk-averse, assumptions and criteria in the development of its inventory. Given the extensive damage to property and the costs associated with fire-fighting, outages and service restoration associated with inadequate efforts in the past -- not to mention potential civil and criminal liability -- such a conservative approach is reasonable.

In effect, PG&E's position is that it has recently learned that it must perform 149% more trims and removals than it did in the relatively recent past because it has learned that there are about one million more trees (4.4 million to 4.8 million as opposed to 3.4 to 3.5 million) in proximity to distribution lines than it previously thought it had, and it is more aware of the number of fast-growing trees that require frequent trimming.

PG&E did not fully appreciate until recently, when it developed the inventory, the scope of activities it needs to perform, even if it somehow managed (if at times inadequately) all trees in proximity to its distribution lines.

The question then becomes: if a trim rate of 845,000 trees per year was associated with inadequate practices, what is the appropriate number of trims and routine removals? A concern with PG&E's estimate of 2.1 million trims is that it is not tested by actual experience. If actual experience were to demonstrate that a system average trim rate of 2.1 million per year is associated with adequate, reliable service, that would not preclude a showing in the future that some smaller number of trims would also yield safe and reliable service as well as compliance with applicable trimming requirements.

We will not adopt PG&E's proposed adjustment of more than 200,000 trees requiring trimming due to above-normal rainfall in 1997 and 1998. For prospective test year ratemaking, it is appropriate to use an assumption of normal weather patterns in the forecast of test year expenses.

Based on the foregoing, we are not prepared to accept PG&E's estimated requirement of 2.1 million trims per year or ORA's alternative calculation of 1.242 million. We will adopt PG&E's count of 4.832 million trees requiring systematic trimming as the most reasonable estimate at this time. We will adopt the specific trim cycles for those trees identified by PG&E as having a shorter than average trim cycle. We also adopt the historical system average trim cycle of four years which PG&E relied upon as recently as April 1996, in A.96-04-002 for those trees not otherwise specifically identified. This yields an estimate of 1.841 million trims annually.

We decline to make two modifications to this forecast level of activity for test year 1999 suggested by TURN in its Comments on the Alternate Decision. These two adjustments cumulatively would reduce routine tree trims from an estimated annual level of 1.841 million to 1.591 million annually, and reduce expense by approximately $12.75 million annually as compared with this decision. We note that TURN's new recommended level of activity is still 210,000 annual trims (15%) higher than the PD's proposed level of activity.

TURN accepts the AD's use of a weighted average rather than a simple average applied to the PG&E tree inventory as the appropriate method for estimating routine tree trimming activity. The AD uses the inventory level forecast by PG&E for beginning 1999 and accepted by the PD. TURN argues, however, that the starting point for the inventory should be mid-year 1999, rather than beginning 1999 and argues for inventory adjustments to reflect estimated tree removal activity in 1998 and 1999. This is inconsistent with forecast test year ratemaking. We decline to adopt a mid-year starting point for a test year estimate.

TURN also argues that an error in arithmetic in developing the weighted average results in an overestimate of routine annual activity. TURN bases this argument on misapplication of a four-year trim cycle to a residual "Other " category in the PG&E inventory. (ORA makes this identical argument in its Comments.) PG&E applied a 1.67 year cycle to this "Other" category to reach its initial estimate of 1.886 million trims annually. In this decision, we apply an average four-year cycle to the trees determined to be on a cycle greater than three years (both on specifically identified four, five, six and seven-year cycles and the imputed 1.67). We reach an estimate different from and lower than PG&E's, although higher than TURN's "PG&E adjusted." As a starting point for test year 1999, we find that this is reasonable.

However, recognizing that there is an element of uncertainty in these estimates and that there is interaction between the authorized tree removal program and the level of authorized routine activity, we have accepted TURN's recommendation of a one-way balancing account, the Vegetation Management Balancing Account (VMBA). Beginning with 1999, the VMBA will collect authorized revenues and actual vegetation management expense, and will "true up" these amounts annually to the extent that authorized revenues exceed actual expense. In this way, ratepayers will not be harmed if the estimates we adopt as reasonable for 1999 prove to be imprecise.

7.2.3.3.1.2 Unit Trim Cost

PG&E's tree trimming program is performed by outside contractors. Its forecast unit cost of $54 ($52.43 in 1996 dollars) per tree is based on current contracts in place with tree trimming companies. PG&E explains that this represents a system-wide weighted average for all the contracts and supporting activities. This amount consists of three basic costs: $42 for crew work for tree trimming and removal, $8 for pre-inspection and post-audit functions, and $4 for vegetation program management costs. The crew work involves contract tree crews, supervision, and equipment used to perform the required work. With rare exceptions, crew work is competitively bid via unit cost contracts to ensure PG&E's unit costs are as low as practical. The pre-inspection and post-audit portion is also performed by contractors and is competitively bid. PG&E notes that it is contractually obligated to pay contractors at the competitively bid rate accepted as a result of the bid process.

ORA based its alternative tree trimming cost calculations on the average unit cost of $51 for the period 1987-1994, the $49.58 cost estimate reported by PG&E's Manager of Distribution in an internal communication, and PG&E's estimate of $54 in this GRC. TURN recommends use of the $41 unit cost that PG&E presented in its 1997 Base Revenue Case.

We find the historical average trimming / removal cost of $51 (in 1996 dollars) per unit to be the most reasonable estimate for forecasting test year tree trimming expenses. It is somewhat lower than PG&E's estimate of $52.43 (in 1996 dollars), but as TURN and ORA have pointed out, PG&E's estimate reflects the results of competitive bidding at a time of higher demand and use of out-of-state crews associated with accelerated tree trimming efforts. As PG&E has shown, when reasonable adjustments are made to the base case estimate of $41 that TURN recommends, the difference between the two unit cost estimates is under $4. Subtracting this difference from PG&E's estimate of $54 yields an adjusted estimate of $50 based on TURN's recommendation.

We do not accept further adjustments recommended by ORA for PG&E's "Smart Spending" initiative. PG&E has shown that projected savings of $15 million for tree trimming are largely offset by increased costs.

7.2.3.3.1.3 Conclusion - Tree Trimming

Based on the foregoing, we find that PG&E's estimate of $110.658 million for tree trimming has not been justified. Applying our adopted estimate of 1.841 million trims per year and our adopted unit cost of $51 per tree yields an estimated budget of $93.891 million. We note that while this is substantially less than PG&E's request, it represents an increase of 127 % over the budget of $40 million adopted in PG&E's 1996 GRC.

Given the relative lack of experience with the tree inventory data base and the magnitude of the increase we are approving, we will adopt a one-way balancing account mechanism to track vegetation management expenditures during the time this GRC revenue requirement is in effect, as proposed by TURN. The one-way balancing account approach is further supported by our approval of PG&E's supplemental tree trimming program, which over time will remove the fastest growing trees and thus over time impact the number of trims we have calculated using a weighted average approach. A one-way balancing account will capture the efficiencies created by our approval of the supplemental tree removal program. We expect that in the future, PG&E will utilize its new inventory data base to more effectively manage its tree trimming program. In addition, we believe that PG&E's experience with the consequences of its past tree trimming practices will act as an incentive for it to avoid inappropriate underspending in the future. Nevertheless, the one-way balancing account assures us and the public that if we have significantly erred in adopting this new method of estimating vegetation management activity, we can rectify any error.

7.2.3.3.2 Vegetation Clearing

As PG&E explains in its rebuttal testimony, vegetation clearing, or pole clearing, involves removing vegetation from around the base of certain distribution poles in designated fire areas (subject poles). These poles have equipment or connectors that could potentially ignite vegetation at the base of the pole should they operate or malfunction. The work is mandated by PRC Section 4292 and is typically enforced by the California Department of Forestry and Fire Protection during the fire season.

PG&E's tree inventory program included collection of subject pole data. PG&E determined that it has 135,454 subject poles. Most require annual clearing, but about 20,000 require two clearings during the fire season. PG&E estimates that it must perform 155,000 pole clearings in 1999, and estimates a total budget of $6.795 million. ORA believes that the $1.539 million amount authorized for other vegetation management in the 1996 GRC should be continued and adopted in this GRC.

While the budget proposed by PG&E represents a sizable increase above 1996 authorized levels, it reflects the data obtained by PG&E on the number of subject poles from the new tree inventory data base. We will approve PG&E's estimate.

7.2.3.3.3 Supplemental Tree Removal

PG&E's base tree trimming program, described above, includes tree removal. There is conflicting evidence, but the base program includes either 319,496 or 500,000 annual tree removals. In addition to this provision for routine tree removal, PG&E has established a temporary, supplemental program to remove fast growing trees, and, in some cases, to replace those trees with slower growing varieties. PG&E first stated that the program would operate in 1998 and 1999 and would target trees that require trimming either annually or semi-annually. Later in this GRC, PG&E extended it to a four-year program. PG&E also extended the program to trees that require trimming every two years or less. PG&E forecasts test year expenses of $20.384 million for this program. This forecast is determined by multiplying the estimated number of fast-growing trees that PG&E is seeking to remove from its tree stock by the removal unit cost rate.

ORA and TURN find that this is an appropriate program for PG&E to undertake. However, they recommend that ratepayers not be required to provide funding for this supplemental program because, they assert, it is related to deferred maintenance and involves non-recurring expenses, for which recovery in a GRC is inappropriate.

Discussion

PG&E has described this tree removal program as supplemental to routine maintenance, but it seeks to recover costs for the program on an ongoing basis as though it were a part of the routine tree trimming and removal program. We have already approved an increase of 127% over the amount authorized for tree trimming and removal in the last GRC. Through this extended program, PG&E seeks an *additional* 51% over the previously authorized amount.

As discussed earlier, the tree inventory data base forms the basis for PG&E's supplemental tree removal program. We note that the changes in the scope of this program from the time that PG&E prepared its application to the time it filed its rebuttal testimony may be associated with the evolving nature of the new data base. Although we are not persuaded by PG&E's rebuttal testimony that none of this supplemental activity is associated with deferred activity in the past, we are unable to quantify the impact of inappropriately deferred tree trimming and tree removals. Removal of some fast-growing trees in PG&E's service territory may be a cost-effective and worthwhile project for PG&E to undertake and we approve the requested level of funding, subject to the one-way balancing account treatment established for tree trimming. However , we note that PG&E has not reconciled this request for incremental funding in 1999 with activities that were funded by Section 368(e) in 1997 and 1998. That issue is before us in A.99-03-039, the investigation of spending of section 368(e) funds. Further, the Consumer Services Division is conducting a five-year audit of vegetation management activities, pursuant to settlement of the Rough-and-Ready Fire investigation. These regulatory activities will give us and PG&E an accurate factual basis on which to proceed in the future.

7.2.3.3.4 Adopted Vegetation Management Expense

Based on the foregoing analysis and discussion, we adopt the vegetation management forecast shown in the following table. Based on the resolution of O&M expense forecast methodology which follows, we find that it is reasonable to integrate this forecast in the forecast for Account 593 in lieu of the vegetation management forecast advanced by PG&E.

Adopted 1999 Vegetation Management Forecast (000's omitted, 1996 Dollars)

Item	Amount
Tree Trim / Remove	$93,891
Vegetation Clearing	$ 6,795
Tree Removal	$ 20,384
Total 1999 Forecast	$121,070

PG&E notes that it trimmed or removed over five million trees between 1995 and 1997, and estimates it will have trimmed or removed over two million trees in 1998. The total of over seven million trees exceeds PG&E's total inventory of trees by more than two million. PG&E also notes that it must be in compliance with the new 18-inch clearance requirement by January 23, 1999. With this in mind, we find that it is unlikely (but as TURN has shown, not impossible as PG&E claims) that the bottom-up forecast for vegetation management adopted here includes any substantial amounts associated with past deferred or deficient maintenance practices. Further, because of the relative importance of vegetation management to overall electric distribution maintenance expenses, use of this forecast approach significantly reduces our concern that the adopted forecast of test year expenses might inappropriately reflect past deferred or deficient maintenance.

7.2.3.4 Forecasting Methodology

PG&E used 1996 recorded data for its base year calculation in all electric distribution O&M accounts, except Accounts 586, 587, and 597, for which it used 1997 recorded data.[19] ORA used the same methodology as PG&E for operations accounts, and used a four-year average plus forecast adjustments for maintenance accounts. Several other parties used, or support the use of, multi-year averages to forecast 1999 O&M expenses. The following table summarizes the general approaches used by the parties, but does not reflect all forecast adjustments of the partie.

Electric Distribution O&M Expenses
Summary of Estimating Methodologies

Party	Operating Accounts	Maintenance Accounts
PG&E	1996 Adjusted Recorded*	1996 Adjusted Recorded*
ORA	1996 Adjusted Recorded	4-Year Average (1993-1996)
Enron	3-Year Average (1995-1997)	5-Year Average (1992-1996)
Weil	Supports ORA's Forecast	5-Year Average (1992-1996)
TURN	Supports ORA's Forecast	Supports ORA's Forecast
CFBF	Disallowance**	Disallowance**

* PG&E used 1997 recorded data for Accounts 586, 587, and 597.

** CFBF subtracted 1987 to 1996 recorded costs from the adopted amounts over the same period and amortized the result over the test year and two attrition years. PG&E incorrectly refers to CFBF's recommendation as an "Amortized Penalty."

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19 In May 1996, PG&E installed a new business system based on software provided by SAP AG. Start-up problems with the SAP-based system required adjustments to 1996 recorded data for purposes of developing cost estimates in the GRC application. References to 1996 recorded data include the adjustments where appropriate.

PG&E states that it used 1996 recorded amounts as its base year to forecast test year electric distribution O&M expenses because 1996 reflects a level of distribution O&M spending that is most representative of the work it believes is necessary to provide the level and quality of service delivered in 1999. PG&E asserts that given the consistent level of distribution O&M spending in 1996, 1997, and 1998, and the changes in PG&E's business accounting system,[20] it is particularly critical in this GRC to use a forecast methodology that relies on recent, rather than historic, data.

Other parties find 1996 to be an outlier year of unusually high costs, and recommend an average of three or more years of recorded expense data to more accurately reflect test year requirements. As Weil explains:

> "As a general proposition, use of averages and trends is superior to reliance on a single base year, at least for stable utility functions like distribution, because averages and trends incorporate more historical data. The role of distribution has been relatively unchanged by electric restructuring." (Weil Opening Brief, p. 21.)

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20 In 1996, PG&E ended the use of supervision and engineering accounts (Accounts 580 and 590). Costs formerly recorded in those accounts cascade to the various FERC accounts primarily as a function of how field forces charge their time. PG&E notes there has also been cost shifting between accounts. Also, some costs that were previously recorded as A&G are now recorded in O&M accounts. In its Opening Brief (at p. 109), PG&E presented a similar table showing gross additions recommendations for PG&E and ORA and net additions recommendations (reflecting retirements) for Enron. The net additions recommendations shown in this table for PG&E and ORA are taken from the Comparison Exhibit. (Exhibit 474, p. A-125.)

Weil points out that use of data from 1997 in a multi-year average is problematic since a portion of 1997 recorded O&M spending includes Section 368(e) funding, which should not be reflected in test year forecasts. Enron agrees, and used 1992-1996 data for maintenance accounts. Enron used 1997 data for operations account forecasts, having determined that PG&E did not increase its 1997 expenditures in operations forecasts.

Discussion

The Commission has recognized that there are different valid and acceptable methods for account-by-account forecasting test year costs in a GRC, including using a single recorded year's expenses (as PG&E proposes) and using multi-year average recorded costs (as other parties propose). The question at hand is which of these two methods yields the most accurate and reliable forecast of test year expenses. In PG&E's test year 1990 GRC the Commission described the following criteria for developing a base estimate of test year expenses:

> "If recorded expenses in an account have been relatively stable for three or more years, the 1987 recorded expense is an appropriate base estimate for 1990.
>
> "If recorded expenses in an account have shown a trend in a certain direction over three or more years, the 1987 level is the most recent point in the trend and is an appropriate base estimate for 1990.
>
> "For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typical four years) is a reasonable base expense for the 1990 test year." (D.89-12-057, 34 CPUC2d 199, 231.)

With respect to a particular account in that GRC (Account 588), the Commission went on to state:

> "Absent a specific explanation of why 1987 recorded data best reflects the estimated 1990 expenses of an account with fluctuating expense levels and no discernible trends, we find it most appropriate to use a four-year average as the base 1990 estimate." (*Id.*, 238.)

We find these criteria to still be generally applicable for our determinations here. For operations accounts, the fact that the parties' forecasts of total operations expenses fall within a narrow range reveals that relatively little difference is attributable to the method used. This appears to reflect relative stability in the level of expenditures on operations. Consistent with the above criteria, we adopt PG&E's use of recorded 1996 data for operations accounts.

For maintenance accounts, the criteria from D.89-12-057 generally favor the use of averages for this GRC. ORA found that none of the maintenance accounts met the criteria that would suggest use of a single base year--not one of the maintenance accounts remained steady or exhibited a uniform trend during the 1993 to 1996 period. Moreover, the use of 1996 recorded data as the primary basis for forecasting test year expenses creates a problem, given our general finding that some portion of 1996 spending reflects efforts to remedy the effects of PG&E's past maintenance practices.

However, given our finding that PG&E was spending less than it reasonably should have in the years before 1995, the use of recorded data from those years also creates a problem. PG&E significantly reduced its workforce in the 1993 to 1994 time period, and its 1996 GRC showing included adjustments reducing distribution O&M expenses to reflect downsizing. In 1995, PG&E canceled planned layoffs of 800 employees, established a hiring hall, and hired

276 additional permanent employees. Also, 1996 was the first full year that PG&E managed its O&M activities using updated and improved inspection and maintenance programs initiated in 1995, subsequent to the storms of that year and the associated major power outages and extensive damage to electric distribution facilities. Thus, the use of a four-year average that includes two years when PG&E was almost certainly spending less than it reasonably should have on maintenance will yield a less reliable estimate of PG&E's legitimate spending needs in 1999. For this reason, a five-year average that includes three years of such underspending may be even less reliable.

On balance, for electric distribution maintenance accounts other than vegetation management, we find that the use of 1996 recorded adjusted expenditures is likely to yield more accurate forecasts of reasonable expenditures for 1999 than averaging. While the extent to which 1996 expenses reflect deferred or deficient maintenance practices of the past is not quantified, the use of a separate, bottom-up forecast for vegetation management, the major area where PG&E's past practices were most clearly lacking, eliminates much of our concern in this regard. We note that when vegetation management expenses are isolated, the differences in the parties' forecasts of total maintenance expenses attributable to the forecast method used are less significant. Using the four years of historical data that ORA used to calculate base amounts for maintenance accounts (but including 1997 recorded amounts for Accounts 586, 587 and 597), PG&E subtracted recorded amounts for vegetation management expenses for each year and used the resulting values to calculate an average for every O&M account. This resulted in a base amount of $228.3 million excluding vegetation management expenses. Adding PG&E's forecasted base vegetation expenses of $117.5 million to $228.3 yielded a total of $345.8 million, which is within 2% of PG&E's $351.3 million base estimate using 1996 as the base year.

PG&E offers additional reasons for rejecting the use of averaging recorded maintenance costs. PG&E contends that O&M activities are interdependent, and should be forecast using the same methodology. Thus, if 1996 is used as the base year for forecasting operations accounts, it should be used for maintenance accounts as well. PG&E notes that if ORA had used a four-year average for both operations and maintenance, its total recommendation would have been $304.2 million, significantly greater than ORA's recommendation of $288.6 million for O&M. Also, PG&E contends that using an average of recorded costs for maintenance accounts that pre-dates PG&E's new accounting system is inaccurate and inappropriate. While these reasons are not of overriding importance, and are not sufficient grounds for rejecting the use of averaging, they support our determination to use 1996 recorded data for both operations and maintenance accounts.

CFBF took a different approach than other parties to recommend authorized O&M expenses for 1999. It recommends a total disallowance to O&M accounts for "under-spending of past approved revenues that has resulted in a degraded distribution system." CFBF compared recorded costs with adopted amounts from 1987 through 1996 and amortized the difference over the test year and two attrition years. The result is a disallowance of $171.6 million from PG&E's O&M request.

As discussed earlier, a pattern of underspending is relevant to a GRC test year forecast if past maintenance practices and spending have affected base year estimates and, ultimately, test year forecasts, or if it can be shown that ratepayers are being asked to pay twice for a given activity. As we have found, the amount of increased expenditures in 1996 associated with past practices is unquantified, but is likely to be less than the amounts measured by CFBF when vegetation management expenses are removed. In effect, CFBF's approach of disallowing previously-authorized but unspent amounts would hold utilities to a standard of having to expend all authorized amounts. This would be a major, unjustified departure from established test year ratemaking principles discussed earlier.

7.2.3.5 Conservation Voltage Regulation (CVR) Program

Within limits, a lower customer service voltage will result in the consumption of fewer kWh with no change in lifestyle or electricity usage. The CVR program was implemented more than 20 years ago to ensure that the voltage levels for distribution circuits are set at the lowest level reasonable in order to reduce energy consumption. PG&E's Tariff Rule 2 establishes two classes of distribution circuits. For services with a nominal service voltage of 120 volts, Rule 2 specifies a 114 volt minimum for all circuits, a 120 volt maximum for Class A circuits, and a 126 volt maximum for Class B circuits.

TURN points out that to the extent that PG&E exceeds designated voltages, it is selling more energy than customers need and is violating its tariff. TURN raises two issues with regard to PG&E's compliance with the CVR program. First, TURN notes that PG&E was not able to quantify the number of Class A circuits that it maintains. The last data was collected in 1985, leading TURN to conclude that PG&E cannot assure us that it is in compliance with Rule 2. Second, TURN finds that PG&E has a practice of not assigning CVR Class A ratings to newly constructed circuits. Based on these concerns, TURN requests that the Commission direct PG&E to resume the data collection necessary to ensure compliance with CVR program requirements and Tariff Rule 2. In particular, TURN seeks reinstatement of CVR program reporting requirements that were eliminated in 1992 by D.92-12-057. TURN also seeks a Commission directive encouraging PG&E to classify all new circuits under Class A or justify why such classification is not appropriate.

PG&E responds that TURN has not identified any real problem. PG&E maintains that it has a policy to regulate its primary voltage at the lowest practicable level without going below the minimum service limits stated in Rule 2. PG&E further asserts that it does not raise primary voltage levels unless a valid low voltage complaint is not resolvable without a voltage regulation change and would otherwise require additional capital investment to resolve.

There is no evidence that PG&E is out of compliance with Rule 2. More generally, there is no evidence that PG&E is systematically serving distribution customers at unnecessarily high service voltage levels. Accordingly, we are not persuaded that we should overturn our 1992 finding that there was no reason to continue then-existing CVR reporting requirements. We encourage PG&E to act vigorously to carry out this beneficial program in connection with both existing circuits and newly installed circuits. Absent more definitive evidence of a need for doing so, we will not issue new regulatory mandates at this time.

7.2.3.6 Account-by-Account Analyses

This section addresses forecast adjustments and other issues pertaining to operation accounts (Accounts 580, 582, 583, 584, 585, 586, 587, 588) and maintenance accounts (Accounts 590, 591, 592, 593, 594, 495, 596, 597, and 598).

7.2.3.6.1 Account 580 - Supervision and Engineering Expenses

PG&E no longer uses this account, and since we are using 1996 data (1997 data for Accounts 586 and 587), no separate estimate is necessary for this account.

7.2.3.6.2 Account 582 - Station Expenses

PG&E’s estimate for this account for 1999 is $5,731,000. Enron’s estimate is $5,272,000. The difference is attributable to Enron’s use of a three-year average. Based on our adoption of PG&E’s forecast method, we adopt PG&E’s estimate.

7.2.3.6.3 Account 583 - Overhead Line Expenses

PG&E's estimate for this account for 1999 is $19,294,000. ORA's estimate is $18,467,000. This difference is attributable to additional savings that ORA projects from the implementation of Work Management Systems. Enron's estimate of $18,498,000 is based on its use of a three-year average. Consistent with our determination in Section 9.6 regarding IT projects and Work Management Systems savings, and based on our adoption of PG&E's forecast method, we adopt a forecast of $18,467,000.

7.2.3.6.4 Account 584 - Underground Line Expenses

PG&E's estimate for this account for 1999 is $17,367,000. ORA's estimate is $16,640,000. This difference is attributable to additional savings that ORA projects from the implementation of Work Management Systems. Enron's estimate is $11,123,000. The difference between PG&E and Enron is attributable to Enron's use of a three-year average as well as Enron's recommendation for disallowance of PG&E's forecast adjustment of $2,840,000 in costs to patrol underground facilities. TURN accepts the premise of a forecast adjustment for visual patrols, but recommends reducing the amount by $946,667.

PG&E states that its forecast adjustment for line patrols results from the new requirement in GO 165, adopted in March 1997 by D.97-03-070, to conduct annual and biennial patrols of underground facilities. PG&E contends that the forecast adjustment is necessary because 1996 expenditures do not reflect the cost of performing this work. PG&E's calculation of the adjustment reflects an overtime rate of $300 per day. By comparison, the non-overtime rate for employees used for overhead inspections is $200 per day.

Enron disputes the adjustment because (1) PG&E proposes to conduct annual inspections in rural areas, where D.97-07-030 requires only biennial inspections; (2) PG&E calculated the costs assuming that patrols will be conducted on an overtime basis; and (3) incremental expenditures associated with Account 584 could be largely offset by reductions to amounts recorded in Account 583 that could be realized if PG&E reduced the frequency of overhead inspections in rural areas to a level that meets the standard. TURN's recommended reduction to the adjustment is based on its objection to PG&E's assumption of overtime rates. TURN's proposed reduction of $946,667 is based on its proposed use of a daily cost of $200 rather than $300.

We find that a forecast adjustment for underground equipment patrols is appropriate in light of new requirements, but we also find that PG&E's adjustment should be reduced to reflect more reasonable assumptions. PG&E's contentions regarding administrative problem of maintaining maps and records notwithstanding, PG&E has not justified including the cost of annual inspections in rural areas where recently adopted standards require inspections half as often. PG&E estimates that approximately 60% of its underground circuit mileage is in urban areas, and believes that an even greater proportion of underground equipment subject to inspection may be located in urban areas. Using a 60% urban and 40% rural allocation as the most reasonable estimate, it is reasonable to reduce the 40% rural component by one-half. Accordingly, PG&E's forecast adjustment of $2,840,000 should be reduced by 20%. In addition, despite PG&E's contentions regarding displacement of other work to overtime, PG&E has not justified the assumption of overtime pay for this activity. Accordingly, the adjustment should be further reduced by one-third. The adopted adjustment for underground patrols is $1,514,667, or $1,325,333 less than PG&E's proposed adjustment.

Consistent with this determination, our adoption of PG&E's forecast method, and our determination in Section 9.6 regarding IT projects and Work Management Systems savings, we adopt a forecast of $15,314,667.

7.2.3.6.5 Account 585 - Street Light & Signal Systems Expenses

PG&E's estimate for this account for 1999 is $367,000. Enron's estimate is $432,000. The difference is attributable to Enron's use of a three-year average.

CAL-SLA intends to examine Accounts 585 and 596 to ensure that these accounts decrease in the future, consistent with the sales of streetlight facilities to public agencies. However, CAL-SLA does not take specific issue with PG&E's forecast. Accordingly, based on our adoption of PG&E's forecast method, we adopt PG&E's estimate.

7.2.3.6.6 Account 586 - Meter Expense

PG&E's estimate for this account for 1999 is $6,373,000. Enron's estimate is $17,758,000, which is based on Enron's use of a three-year average. Based on our adoption of PG&E's forecast method, we adopt PG&E's estimate.

7.2.3.6.7 Account 587 - Customer Installation Expenses

PG&E's estimate for this account for 1999 is $28,967,000. ORA's estimate is $27,272,000. This difference is attributable to additional savings that ORA projects from the Field Automation System. Enron's estimate is $22,968,000, which is based on its use of a three-year average.

Based on our adoption of PG&E's forecast method, and consistent with our determination in Section 9.6 regarding IT projects and Field Automation Systems savings, we adopt a forecast of $22,272,000.

7.2.3.6.8 Account 588 – Miscellaneous Expenses

PG&E's estimate for this account for 1999 is $50,733,000. ORA's estimate is $47,468,000. This difference is attributable to additional savings that ORA projects from the implementation of Work Management Systems and cost disallowances associated with the Facility Information Database IT project. Enron's estimate of $44,711,000 is based on its use of a three-year average.

Based on our adoption of PG&E's forecast method, and consistent with our determination in Section 9.6 regarding IT projects, Field Automation Systems savings, and disallowances associated with the Facility Information Database IT project, we adopt a forecast of $47,468,000.

7.2.3.6.9 Account 590 - Supervision and Engineering Expenses

As noted earlier, PG&E no longer uses this account. Enron recommends $8,719,000 for this account. Since we are using 1996 cost data (1997 data for Account 597) as the base estimate for maintenance accounts, no separate estimate is necessary for this account.

7.2.3.6.10 Account 591 - Structures and Improvements

PG&E's estimate in this account for 1999 is $2,565,000. ORA's estimate is $3,219,000. Enron's estimate is $2,613,000. The differences are due to different estimating methods. No party recommended forecast adjustments for this account. Based on our adoption of PG&E's forecast method, we adopt PG&E's estimate.

7.2.3.6.11 Account 592 - Station Equipment

PG&E's estimate in this account for 1999 is $17,879,000. ORA's estimate is $12,158,000. Enron's estimate is $10,981,000. The differences between the various estimates are due to different estimating methods. No party recommended forecast adjustments for this account. Based on our adoption of PG&E's forecast method, we adopt PG&E's estimate.

7.2.3.6.12 Account 593 - Overhead Lines

PG&E's estimate in this account for 1999 is $182,553,000. ORA's estimate is $110,514,000. Enron's estimate is $106,383,000. The differences are due to the different estimating methods and reflect, among other things, the disparate positions of the parties regarding vegetation management costs.

PG&E recommends forecast adjustment increases for vegetation management (discussed earlier) and for certain pole test and treat program costs (discussed below). PG&E also recommends forecast adjustment decreases for completing the pole inventory program and savings associated with the implementation of Work Management Systems. ORA accepts these latter adjustments. Enron recommends no forecast adjustments.

PG&E is performing a system-wide wood pole test-and-treat program to extend the life of these assets. Poles older than 10 years receive an intrusive structural integrity test and remedial preservative treatment if the pole meets pre-determined strength requirements. Poles not meeting strength requirements are evaluated for reinforcement or replacement. In its original testimony, PG&E included a forecast adjustment increase of $14,736,000 for this activity. In its March update, PG&E revised the proposed adjustment to $4,948,000 to reflect a change in the number of poles to be worked per year and PG&E's anticipation that it will not receive payment from telecommunications companies for jointly-owned poles that PG&E tests-and-treats. In rebuttal testimony, PG&E witness Carruthers explained that $3.2 million of the requested adjustment reflects PG&E's estimate of amounts it will not receive from telecommunications utilities and that $1.7 million reflected the "residual increase as a result of working more poles in 1999." Carruthers went on to state that the $1.7 million component was no longer necessary in this proceeding. Thus, according to PG&E, its current proposal for the pole test-and-treat adjustment only reflects its anticipation that it will not receive reimbursement of $3.2 million reimbursement from telecommunications utilities for work on jointly owned poles.

PG&E's attempt to convert the underlying issue for this adjustment to the question of whether Pacific Bell or any other telecommunications utility will share costs of testing and treating jointly owned poles does not change the fact that the underlying cost pertains to a supplemental maintenance program. That program grew out of the Bain report and is associated with PG&E's past inadequate maintenance practices, when PG&E gave inadequate attention to pole test-and-treat activities. PG&E has not shown that it is reasonable to charge ratepayers for this expense through this GRC. We support appropriate cost sharing for the costs of testing and treating jointly owned poles. However, this is not the appropriate proceeding to resolve alleged deficiencies in GO 165.

Based on our adoption of PG&E's forecast method, our adopted vegetation management forecast of $121,070,000 as compared with PG&E's requested forecast adjustment of $137,837,000), and disallowance of PG&E's proposed forecast adjustment of $3,200,000 for its supplemental pole test-and-treat costs, we adopt a forecast of $162,586,000 for Account 593.

7.2.3.6.13 Account 594 - Underground Lines

PG&E's estimate in this account for 1999 is $22,407,000. ORA's estimate is $21,616,000. Enron's estimate is $14,511,000. The differences are due to different estimating methods and Enron's rejection of forecast adjustments.

ORA does not take issue with PG&E's forecast adjustment increase of $5,254,000. PG&E and ORA also agree on PG&E's forecast adjustment decrease of $448,000 to reflect savings associated with the implementation of Work Management Systems, and the net adjustment of $4,806,000. Enron rejects these forecast adjustments.

PG&E's proposed adjustment of $5,254,000 reflects spending to enhance underground system reliability and safety. Under the general heading of "productivity, reliability, safety, and service improvements," PG&E witness Carruthers describes three initiatives pertaining to approximately 19,000 miles of underground primary voltage cable: injection of silicon insulating fluid to extend the life of polyethylene insulated cable, replacement of 200 amp elbow cable terminators and pin and socket straight splices, and replacement of diamond plate underground enclosure covers with oxide imbedded covers. PG&E planned to complete the replacement of covers in 1998. In its March update testimony, PG&E indicated that cable injection and elbow and splice replacement would take place in 1999 as well as 1998.

Against a background of past inadequate maintenance and substantial legislative funding of safety and reliability enhancements in 1997 and 1998, as well as scant explanation of the nature and duration of this incremental activity, we find that PG&E has not provided sufficient justification for ratepayer funding of this incremental activity through this GRC. We therefore deny PG&E’s adjustment of $5,254,000. Based on this determination, and our adoption of PG&E's forecast method, we adopt a forecast of $17,153,000 for Account 594.

7.2.3.6.14 Account 595 - Line Transformers

PG&E’s estimate in this account for 1999 is $6,138,000. ORA’s estimate is $5,349,000. Enron’s estimate is $5,834,000. The differences are due to different estimating methods and PG&E’s and ORA’s agreement on PG&E’s forecast adjustment decrease to reflect savings associated with the implementation of Work Management Systems. Based on the forecast adjustment, and our adoption of PG&E's forecast method, we adopt PG&E’s forecast of $6,138,000.

7.2.3.6.15 Account 596 - Street Lighting and Signal Systems

PG&E’s estimate in this account for 1999 is $5,229,000. ORA’s estimate is $2,724,000. Enron’s estimate is $2,582,000. The differences are due to different estimating methods. PG&E and ORA agree on PG&E’s forecast adjustment decrease to reflect savings associated with the implementation of Work Management Systems. PG&E and ORA also agree that there should be a forecast adjustment decrease associated with changes in the number of street lights, although by different amounts. The difference appears to be explained by the fact that PG&E revised its estimate for this account in errata.

As previously noted, CAL-SLA intends to examine Accounts 585 and 596 to ensure that these accounts decrease in the future, consistent with the sales of streetlight facilities to public agencies. However, CAL-SLA does not take specific issue with PG&E's forecast. Based on PG&E's uncontested forecast adjustments, and our adoption of PG&E's forecast method, we adopt PG&E's forecast of $5,229,000.

7.2.3.6.16 Account 597 - Meters

PG&E's estimate in this account for 1999 is $11,512,000. ORA's estimate is $3,450,000. Enron's estimate is $2,476,000. No party recommends forecast adjustments for this account. The differences are due to different estimating methods. Based on our adoption of PG&E's method, we adopt PG&E's forecast.

7.2.3.6.17 Account 598 - Miscellaneous Distribution

PG&E's estimate in this account for 1999 is $12,204,000. ORA's estimate is $7,363,000. Enron's estimate is $5,528,000. No party recommends forecast adjustments for this account. The differences are due to different estimating methods. Based on our adoption of PG&E's method, we adopt PG&E's forecast.

7.3 Capital

7.3.1 Generation

Generation capital expenditures are considered in this GRC for common cost allocation and to comply with Ordering Paragraph 4 of D.97-12-096. ORA and PG&E are in agreement regarding the use of PG&E's fossil, hydroelectric, and geothermal rate base for the purpose of cost allocation. The only contested issue is a proposed modification of the capital component of the revenue requirement architecture adopted in D.97-12-096 for PG&E's hydroelectric and geothermal generation facilities which have not been divested or otherwise market-valued. The capital-related revenue requirement is currently based on recorded monthly costs.

In adopting the hydroelectric and geothermal revenue requirement mechanism, we recognized that, compared to traditional cost-of-service ratemaking or PBR, recorded cost ratemaking tends to make management less concerned with controlling capital-related costs. (D.97-12-096, mimeo., p. 6. and Finding of Fact 4, p. 28.) However, the record in that proceeding did not include a forecast of capital-related costs, and we approved recorded cost ratemaking, at least on an interim basis. We also provided that the use of a forecast of capital-related costs in lieu of recorded cost ratemaking after 1998 would be reviewed in this GRC. (*Id.*, Conclusion of Law 5, p. 31.) With such a review in mind, we directed PG&E to submit a forecast of the capital-related revenue requirement for its hydroelectric and geothermal generation facilities in this GRC. (*Id.*, Ordering Paragraph 4, p. 33.) PG&E forecasts a capital-related revenue requirement of $277,890,000 for hydroelectric generation and $73,817,000 for geothermal generation. No party contests the validity or accuracy of these forecasts, although PG&E does not advocate their use in the revenue requirement mechanism.

Weil proposes that we modify the revenue requirement architecture by directing PG&E to cease recorded cost ratemaking and to use instead a forecast of capital-related costs. PG&E opposes this recommendation, contending that the risk of recovery of uneconomic generation costs by the end of the transition period provides an incentive that offsets the problems of recorded cost ratemaking discussed in D.97-12-096. Weil counters that given the size of PG&E's overall request in this GRC, the large increase sought by PG&E in

A.98-05-019, and PG&E's goal of extending the rate freeze through 2001, one cannot conclude that the risk of transition cost recovery provides PG&E with adequate incentive to reduce expenditures under recorded cost ratemaking.

As we noted in D.97-12-096, we generally do not favor recorded cost ratemaking such as that embodied in the revenue requirement mechanism adopted in that decision. PG&E's argument that the risk of stranded cost recovery provides adequate incentive to manage capital costs is not persuasive in light of evidence noted by Weil regarding the efficacy of the risk of transition cost recovery, as well as our stated preference for the stronger incentives associated with forecast ratemaking. Accordingly, as we anticipated we might in D.97-12-096, we direct PG&E to modify its hydroelectric and geothermal revenue requirement mechanism to replace the use of recorded capital costs with forecast costs set forth in Exhibit 28.

7.3.2 Transmission

ORA and PG&E agree on transmission plant additions through 1999 and on the 1999 weighted average transmission plant, with one adjustment. ORA recommends a weighted average transmission plant of $2,251,127,000, while PG&E recommends $2,251,831,000. The difference is due to ORA's recommended special plant reduction in 1998 of $704,000 in connection with structurally overloaded transmission wood poles. ORA proposes a similar adjustment of $10.194 million for wood distribution poles. These poles need replacement because they violate the GO 95 rules and other safety and reliability concerns. ORA's recommended adjustment reflects PG&E's determination that it caused the structural overloading 20% of the time, and that telecommunications utilities, primarily Pacific Bell, are otherwise responsible for the overloading.

As ORA contends, once ratepayers have paid for an asset, they should not be forced to pay for premature replacement of the same asset due to its structural overloading by PG&E or its joint users. PG&E initially took issue with the proposed adjustment for transmission poles, but in its reply brief stated that there are no issues of dispute in the area of electric transmission capital. We adopt ORA's recommended adjustment. In the following section we address the application of this determination for distribution poles.

ORA requests that the Commission establish a suitable forum by which Pacific Bell can be ordered to refund an estimated $736,000 for structurally overloaded transmission poles. PG&E supports this ORA recommendation. We will direct our staff to review this specific request and the general issue of assignment of cost responsibility for repair or replacement of structurally overloaded poles in violation of our standards. The review should include a determination of the extent to which actions described in D.99-06-080 (at mimeo., p. 27, *et seq.*) obviate the need for an additional proceeding. If appropriate, staff should recommend any necessary action to resolve the issue of cost sharing associated with the repair and replacement of structurally overloaded poles.

7.3.3 Distribution

7.3.3.1 Introduction

Electric distribution capital expenditures are made to address safety and reliability issues, connect new customers, increase capacity to serve additional load, and relocate and rearrange facilities to meet customers' or regulatory needs. The divergent forecasts of electric distribution capital expenditures represent another of the major areas of controversy in this proceeding. PG&E's forecast of capital additions for the three-year period 1997-1999 is $2.38 billion. It is based on what PG&E describes as a "bottoms up / top down" analysis, described below.

ORA's recommendation of $1.25 billion in capital additions for the same period is based on a regression analysis which uses recorded data from 1986 through 1996 for gross plant additions, the number of new customers, the average number of customers, total plant in service, and total sales in MWh. TURN and AECA support ORA's recommendation, although TURN presented a secondary recommendation to reduce PG&E's estimated capital additions by $350 million. Enron uses a five-year average of recorded data (1992-1996) for estimating net additions. The following table shows PG&E's, ORA's, and Enron's recommended plant additions: [21]

Recommended Electric Distribution Plant Additions 1997-1999 (in Millions)

Year	PG&E Gross	PG&E Net	ORA Gross	ORA Net	ENRON Net
1997	$ 745	$ 713	$ 442	$ 386	$ 417
1998	$ 843	$ 763	$ 355	$ 229	$ 422
1999	$ 792	$ 709	$ 449	$ 394	$ 430
Total	$2,380	$2,184	$1,245	$1,009	$1,269

In the following sections we evaluate the recommendations put forward by PG&E (Section 7.3.3.2), ORA (Section 7.3.3.3), TURN (Section 7.3.3.4), and Enron (Section 7.3.3.5), then, based on the evaluations, conclude with our adopted capital additions forecast (Section 7.3.3.6).

21 In its opening brief (at p. 109), PG&E presented a similar table showing gross additions recommendations for PG&E and ORA and net additions recommendations (reflecting retirements) for Enron. The net additions recommendations shown in this table for PG&E and ORA are taken from the Comparison Exhibit. (Exhibit 474, p. A-125.)

7.3.3.2 PG&E's Forecast

PG&E's plant additions estimates are based on what it refers to as a bottoms up / top down forecast approach. The request includes recorded 1997 plant additions. PG&E asserts that this approach takes regulatory and statutory requirements and economic conditions into consideration and is supported by expert operating and engineering judgment, gained through years of hands-on experience with PG&E's electric distribution system and service territory. According to PG&E, this method is similar to that used in previous GRCs.

PG&E explains that a "top level system overview" forecast based upon prior years' expenditure levels, system-wide performance trends, and other key drivers was compared with a bottoms-up plan in which operating personnel developed forecasts for each of their respective areas based on local conditions. These local forecasts were shared with PG&E's general office staff who reviewed and analyzed the information to create the system-wide plan that forms the basis of PG&E's estimate in this GRC. PG&E states that data sources include system-wide and circuit-specific reliability data, field observations on the condition of the distribution facilities, load and customer growth data, direct feedback from customers, and Customer Opinion Surveys. PG&E contends that this method ensures that it meets all regulatory requirements, as well as Commission and customer expectations for safe, reliable, and responsive service.

PG&E points out that there are thousands of routine, recurring capital projects under $1 million, and that the details of these expenditures are not known at the time its forecast is developed. Expenditures for these projects are forecast at an aggregate level by Major Work Category (MWC). MWC 06, Construct / Acquire New Facilities / Capacity Investment, includes projects to meet load growth such as new substations and new transformer banks in existing substations. MWC 08, Improve System Reliability / Replace Deteriorated

Facilities, accounts for the largest portion of PG&E's electric distribution capital expenditures. It includes work designed to prevent the occurrence of outages and limit their effect. Examples include replacing and reinforcing poles and replacing substation equipment. MWC 10, Work at the Request of Others, includes relocating and rearranging facilities. MWC 16, Electric New Business, includes capital additions to establish service to new customers. The work includes primary voltage extensions for new subdivisions as well as service drops from existing facilities. MWC 17, Emergency Response, covers capital expenditures made to replace failed components. MWC 25 covers purchased meters. MWC 30, covers projects to convert existing overhead facilities to underground facilities.

For a more complete understanding of PG&E's approach, we look to ORA's testimony:

> "The forecasted capital additions requested for 1997, 1998, and 1999 were based on the 1997 capital budget for the major work categories (MWCs). The development of the 1997 budget began in mid 1996 based on input from field offices and was subsequently reviewed and adjusted by the general office staff. The 1997 overall capital expenditures by MWC were either escalated by 2 percent or adjusted by the general office staff to estimate the capital expenditures for 1998 and 1999. Each MWC capital expenditure was further divided into two categories: the first included projects exceeding one million dollars and the second included projects under one million dollars. This was accomplished by identifying and adding the cost of projects over one million dollars and subtracting it from the overall MWC capital expenditures forecast to obtain the expenditures for projects under one million dollars." (Exhibit 73, p. 11C-3.)

In testimony submitted with the application, PG&E identified the following "significant issues" as having an important effect on distribution capital expenditures: asset management, increasing reliability expectations, and

California's economic recovery since 1995. Under the heading of asset management, PG&E states that the storms of 1995 put the distribution system to an extreme test. This lead PG&E to determine that a significant effort to improve overall system reliability was necessary. With respect to increasing reliability expectations, PG&E refers to the technology boom of the 1980's and customers' heightened awareness and even intolerance of outages and other power system disturbances. For example, PG&E believes that momentary outages have a different effect on customers in the 1990s than they did in the 1970s. PG&E concludes that it should commit to improving the overall reliability of its electric distribution system on behalf of more demanding customers, such as residential customers with home businesses, which requires increased spending. With respect to economic recovery, PG&E states that the end of the recession in California is a significant factor for the higher projected capital expenditures for 1997, 1998, and 1999. PG&E notes in particular California job growth of 2.8% in 1996 and 2.7% in 1997, as well as fast growing areas within its service territory, such as Silicon Valley, the Sacramento Valley, and the Livermore and San Ramon Corridors. PG&E asserts that the effect of increased economic activity is unexpectedly high load growth, requiring system improvements to be made sooner than otherwise. System-wide, PG&E estimated that peak distribution load would grow from 15,708 MW in 1996 to more than 15,900 MW in 1997 and 16,100 MW in 1998. PG&E estimated that system expenditures for capacity expansion projects would approach $500 million for the period 1997-1999.

In addition to these three significant issues affecting capital expenditures, PG&E has identified three "key drivers" of distribution capital investments: customer and load growth, safety and compliance, (including reliability), and work required by others. Customer and load growth encompasses MWCs 06 and 16 and includes connection of new customers to the existing distribution system and upgrading or adding new distribution facilities to accommodate these new customers' load and other existing customers' load increases. Safety and compliance encompasses MWCs 08 and 17 and involves ensuring a safe distribution system for customers and employees, meeting customer reliability expectations, correcting failed distribution facilities (including emergency response), and replacing aging assets before they fail. Work required by others encompasses MWCs 10 and 30 and involves upgrading and moving of distribution facilities as requested, undergrounding of overhead facilities, and complying with environmental initiatives and demand side management work. The following table, abstracted from data presented by PG&E in Table H of its rebuttal testimony (Exhibit 28), shows PG&E's breakdown of its proposed capital additions by these drivers.

PG&E's Plant Additions
By "Key Drivers"
1997-1999 (in Millions)

	1997 Actual	1998 Forecast	1999 Forecast
Customer and Load Growth	$368	$382	$330
Safety & Compliance-Reliability	$303	$373	$376
Work Required by Others	$ 74	$ 89	$ 87
Total (rounding errors corrected)	$745	$843	$792

Parties opposing PG&E's estimates find what they believe to be extensive problems with PG&E's forecast approach. We describe below the major points raised by ORA, TURN, Enron, and AECA in opposition to PG&E's forecast of capital expenditures. We note that for some issues, two or more parties took similar or overlapping positions.

Magnitude of the Increase

PG&E's requested plant additions for the 1999 test year are approximately twice the amount authorized in the previous GRC for 1996. PG&E's proposed capital spending level is the highest in its history.

Net distribution plant additions averaged $385 million (in 1996 dollars) between 1993 and 1996, while PG&E requests approval of net additions of more than $700 million in each of the years 1997 through 1999.

Safety and Reliability

Improved reliability is a major reason for PG&E's increased distribution capital expenditures. For 1999 alone, PG&E identified $70 million in capital spending as being associated with reliability improvements, including $40 million for targeted reliability improvements designed to achieve a 10% improvement in reliability, $18 million for reducing the number, scope, and duration of outages, and $12 million for distribution automation. However, even though customers may want improved reliability, PG&E has not shown that customers have expressed a willingness to pay more for such reliability gains. PG&E has little basis for determining whether its investment decisions result in customers purchasing too much reliability. PG&E did not make use of value-of-service analysis.

PG&E has not shown through objective reliability measures such as SAIDI and SAIFI that it needs to spend more on investments to maintain historic reliability levels. Many outages are beyond the control of PG&E and cannot be prevented or reduced by additional spending.

Through AB 1890, and specifically in Section 368(e), the Legislature provided increased funding for PG&E to make safety and reliability improvements in 1997 and 1998. The language of Section 368(e), in combination with a June 9, 1998 letter from then-Chairman of the California State Senate Committee on Energy, Utilities and Communication to the President of the Commission, indicate legislative intent that the moneys provided by Section 368(e) are adequate to enhance safety and reliability, and that additional, new funding beyond that approved in the last GRC is not necessary for safety and reliability.

PG&E's assertion that it will not be able to provide safe and reliable service if its capital spending is not approved should be disregarded, given that its expenditures for the years 1994, 1995, and 1996 were less than half the amounts requested in this GRC.

Growth and Capacity

The only time when distribution capital spending even approached the current level was the 1988-1990 period, when annual customer growth was more than 50% higher than the level of customer growth in the 1997-1999 period. The number of new residential customers added in the 1989-1991 time period exceeds the additions for 1997 or 1998.

Substation utilization is determined by comparing actual peak loads to the installed capacity of substation transformers. Lower utilization factors potentially indicate the installation of excess capacity. PG&E justifies its substation investments by reference to its average recorded utilization factor of 83% from 1993 to 1997 and projected average utilization factor of 83% for 1998-1999, which are well above the industry average of 71%.[22] However, the capacity used in calculating the utilization factor for 1996 was 20% less than the capacity reported by PG&E to FERC in FERC Form 1. Using the capacity reported to FERC reduces the utilization factor to 67%.

PG&E made investments in substations and line upgrades increasing capacity by 1300 MW in 1997, which would meet the needs of 650,000 new customers. However, PG&E's forecast of customer growth from 1996 through 1999 totals 162,000 customers, and even that forecast is slightly overstated.

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22 In its Opening Brief (p. 118), PG&E updated this analysis to reflect recorded 1998 peak load information in Exhibit 402. This exhibit was introduced on October 7, 1998 and appears to reflect data available as of October 1, 1998, presumably after the peak distribution load in 1998 was likely to have occurred. PG&E did not indicate any change in the installed capacity of substation transformers from 1997 to 1998. PG&E calculated the 1998 actual utilization factor at 83%.

Although PG&E cites customer and load growth as an important contributor to its request, customer and sales growth have not changed significantly over the past several years. Customer growth was 1.1%, 1.3%, and 1.1% in 1995, 1996, and 1997 respectively. In 1997, PG&E had a 10.1% decrease in the number of industrial customers and a 1.2% increase in commercial customers. Peak demand increased 5.6% from 1995 to 1996 but only 1.1% from 1996 to 1997. In developing its forecast PG&E did not consider that economic growth in the Silicon Valley and in California generally is threatened by the “Asian Flu“ economic crisis.

Area-specific growth at the Distribution Planning Area (DPA) level, not system-wide growth, drives the need for capital expenditures. Between 1993 and 1997, 30 of 175 DPAs had peak loads that were less than 50% of available capacity, and another 41 DPAs had peak loads that were less than 70% of capacity. Between 1993 and 1997, PG&E overestimated capacity needs in 60% of its DPA level forecasts.

PG&E has changed its load forecasting methodology to include temperature effects, which has the effect of increasing load and capacity. In the past, PG&E assumed that a small part of the difference between normal and emergency capacity of existing transformers or the utilization rate could be used to carry load if the peak load increased slightly above forecast due to very high temperatures. PG&E now assumes that the system must be able to carry the peak, adjusted for the hottest day in the past five to seven years, without using emergency capacity or adjusting the utilization rate. This new approach may provide a slight increase in reliability but has not been shown to be cost-effective. PG&E’s own standard practice guide provides that transformer loads are allowed to exceed specific internal operating temperatures under limited conditions, including extremely high temperatures. In addition, PG&E’s temperature adjustments rely on a statistical forecasting method but fail to test the statistical significance of temperature parameters.

PG&E makes inappropriate trend line adjustments to its load forecasts. If the previous year’s data is higher than the trend line forecast, PG&E adjusts future data by the difference between actual and forecast data. Only upward adjustments are made, which creates a bias to construction of more facilities. In addition, in some cases PG&E planners misapplied PG&E's stated practice for trend line adjustments by applying the growth from one year to the next rather than the difference between the forecast and the actual load.

Block load is an unusually large single load added to or removed from an area. PG&E has in some cases inappropriately included block load additions in current trend line forecast data as normal load growth.

A regression analysis by TURN for the years 1978-1997 shows that PG&E's capital spending in 1997 was about $170 million more than it would have been after accounting for the size of the system as measured by the number of customers and growth in the number of new customers. The regression analysis shows that for the 1997-1999 time period, there is a difference of $650 million between spending patterns in previous years and PG&E's requested spending.

Emergency Projects

PG&E has an emergency planning criterion which is based on the ability of its facilities to carry the peak DPA load with the largest single element, usually a substation transformer, out of service and all other elements at their higher short-term emergency ratings. Thus, to meet the emergency criterion, the system must be able to serve load on the peak day of the year when a large component such as a substation transformer is out of service. This is commonly referred to as an "N-1" emergency.

The emergency criterion is of limited application, since both outages of substation transformers and peak loads have low probabilities, and both events would have to occur at the same time. In the nine years prior to 1997, PG&E spent a total of $700,000 on a single emergency capacity project in 1992. In 1997, when Section 368(e) funding was available, PG&E spent $37 million on emergency capacity projects, even though the criteria for those projects had existed before 1997. PG&E originally estimated additional spending on emergency projects of $80 million, although it now estimates $18 million for 1998-1999. PG&E admitted that 10 of 22 emergency projects were not needed for normal load purposes until after the test year, and even that number is understated, since projects in Pleasant Grove, Clarksburg, Davis, and Newburg should be included among those not needed for normal purposes until after 1999.

PG&E's planning guide lists additional criteria for the actual installation of emergency capacity, and also provides for economic analysis showing that installation of such capacity has a larger benefit-cost ratio than any other combination of remedial actions such as load transfers, additional switches, fuses or reclosers, tree trimming, etc. However, PG&E conducted no such analyses in at least the past five years, and it is unable to indicate the reliability benefits of the $55 million in capital additions for emergency projects which it has included in this GRC. PG&E acknowledges that in terms of SAIDI/SAIFI values, avoiding substation transformer losses would have little impact. Thus, the benefits of spending on emergency projects are not known, but they are clearly small.

Other Asserted Forecasting Errors

When challenged, PG&E readily removed certain assets from its listing of distribution rate base assets. In addition, PG&E was unable to explain why some assets such as generators are listed as distribution plant. These facts undermine the reliability of PG&E's forecast.

A load transfer from one DPA to another should be reflected in a load reduction in the area losing load equal to the load gained by the acquiring area. TURN found two examples where this symmetry principle was not observed. In one case the transfer out was ignored. In the other case the amount of power transferred into an area where a project was being built exceeded the amount transferred out of the area losing load.

In response to testimony by TURN that PG&E might be able to avoid an expansion project (Rio Dell/Newburg) by power factor correction, PG&E's electric distribution capital witness provided testimony that capacitors simply are not used to defer capacity. Yet, the witness later acknowledged that capacitors have some effect on load carrying capability, and under certain conditions increasing the power factor could avoid or defer installation of equipment to increase substation capacity. PG&E's planning guide provides that power factor correction should be pursued to avoid increasing bank or feeder capacity.

PG&E's Motivation

PG&E has an incentive to increase capital spending to position itself to be the distribution company of choice and to set a high baseline for its expected PBR mechanism.

Recorded Capital Spending

PG&E notes that its actual plant additions for 1997 closely matched the forecast of spending presented in the application. However, this does not demonstrate the reasonableness of the forecast or the level of actual spending.

PG&E contends that to support their lower level of capital spending forecasts, ORA and other parties opposing PG&E's capital expenditures must show that recorded electric distribution capital investments through 1997 were unreasonable or imprudent. However, by basing its forecast of plant additions for 1999 on 1997 spending, PG&E opens up its 1997 spending to strict scrutiny. Moreover, the burden of proof is not placed on PG&E's opponents to show that PG&E's investments were unreasonable.

PG&E was on track to spend $140 million less on distribution capital spending for 1998 than the $843 million it has requested in this GRC. Nevertheless, PG&E was able to meet its capital spending priorities for the year, suggesting that the capital spending estimates presented are unnecessarily high. Since PG&E's aggregate capital spending was projected to remain constant between 1998 and 1999, it is likely PG&E's $700 million level of distribution spending would persist in 1999, again suggesting that PG&E's request of $792 million for 1999 is excessive.

PG&E's Budget Process

PG&E's 1997 budget, which was developed in the latter part of 1996 and reflects the incentive PG&E faced to increase spending, was the starting point for estimates of overall distribution capital expenditures for all major work categories for 1999. In effect, PG&E determined a total level of spending prior to requiring specific projects to be justified strictly for need or positive net present value.

Notwithstanding PG&E's claims of performing a bottoms-up forecast, the budget for projects under $1 million was developed by using 1997 total spending, then subtracting from that total the costs of projects over

> $1 million. The smaller projects were not specifically cost-justified, yet they accounted for more than $650 million, or nearly 80% of the total budget. For 1999, there are almost $700 million in projects under $1 million. ORA notes that PG&E did not even purport to have used a bottoms-up analysis until it filed its rebuttal testimony.

Discussion

PG&E is requesting revenue requirement increases to cover substantial increases in distribution capital spending. PG&E's requested gross plant additions for 1999 alone are $792 million, twice the $396 million amount authorized in the last GRC for 1996. PG&E's requested net plant additions for each of the years 1997 through 1999 are nearly twice those recorded between 1993 and 1996. PG&E's request for 1997 through 1999 would result in a weighted average distribution plant estimate of more than $11 billion, or about 23% more than the weighted average plant of $9.0 billion authorized in the 1996 GRC. Accordingly, and for the reasons discussed in the policy section of this decision, PG&E's proposed capital spending warrants careful scrutiny, and significant weight should be given to credible alternative recommendations. At a minimum, PG&E's request for approval of its decision to essentially double the pace of recently approved and recorded distribution system capital spending warrants full explanation and justification by PG&E.

PG&E's forecast of capital spending on the electric distribution system clearly incorporates and reflects the knowledge, experience, and judgment of field personnel responsible for operating and maintaining the system as well as the company's general office engineers, planners, managers, and officers. Without question, those who participated in assembling the forecast are the most qualified individuals to speak to the condition of PG&E's distribution system, both locally and on a system-wide basis. Moreover, we have no doubt that the investments reflected in PG&E's capital spending request represent desirable system improvements that would promote safety and reliability, and would enable PG&E to do a better job of accommodating growth and responding when work is required by others. However, while it is persuasive for PG&E to show that its capital forecast reflects the collective judgment of those who are most knowledgeable of the system, and that reliability and responsiveness will be improved under its spending plan, we must also consider the economic dimension of the proposed spending.

The record shows that the thought process of the operating and engineering experts and managers who took part in PG&E's forecast effort was not primarily driven by cost-effectiveness analyses, value-of-service studies, or attempts to gauge the willingness of ratepayers to pay for improved reliability. Improved reliability is an important driver of increased capital spending by PG&E in this GRC cycle. While PG&E policy witness Randolph acknowledged the need to maintain system reliability performance without spending large amounts on capital improvements to increase performance over and above historically accepted levels, PG&E's distribution capital forecast reflects a more expansive policy on reliability improvements. We note that "PG&E determined that a significant effort to improve overall system reliability was necessary." (Exhibit 6, p. 13C-4.) It then "committed to improving the overall reliability of its electric distribution system," even though "[t]his commitment requires increased spending to address the reliability needs of many customers." (Exhibit 6, p. 13C-6.) PG&E then stated that it "will spend several hundred million dollars between 1997 and 1999 to improve distribution reliability." (Exhibit 6, p. 13C-8.) PG&E acknowledges that its targeted reliability improvements account for $70 million of its request for 1999, but the evidence shows that even more of the capital spending at issue is directed towards reliability improvements. We find that this overall approach was reasonable.

As we previously observed, even as PG&E was developing this reliability-oriented spending plan, it was operating within a milieu of enhanced incentives to augment spending as the advent of industry restructuring, competition, and PBR loomed near. Improved reliability performance, clearly desirable, may be economically justified to the extent that significant new expenditures are involved. Accordingly, and consistent with our "statutory reliability" determination in D.96-09-045, our focus in this GRC is on approving investments that are required for maintenance of historical levels of reliability, responding to customer and load growth, and performing work required by others.

PG&E notes in its brief that increased reliability capital expenditures of $70 million in 1999 would result in a revenue requirement of $14 million and a cost of approximately $3 per customer per year. This amount is minimal and should be approved. If this minimal cost helps to avoid local or regional outages, it is a bargain. PG&E indicates in its rebuttal testimony that in order to maintain historical reliability levels, it must spend $306 million on distribution capital investments in 1999. This amount is for pole replacement and reinforcement ($72 million), substation equipment replacement ($56 million), underground system enhancement ($15 million), preventative maintenance of distribution lines ($80 million), and outage response ($83 million). PG&E explains in considerable detail the work that will be accomplished with this funding, and no party takes issue with the general need for PG&E to continue investing in these areas. It is prudent for PG&E to reinforce its electric distribution system during this GRC cycle.

The Legislature through Section 368(e) provided PG&E with additional funding for safety and reliability enhancements of its electric distribution system. There is no indication either that the Legislature expected this level of spending to be required indefinitely into the future or that the Legislature considered this to be a complete one-time corrective for reliability problems exposed by the 1995 storms and addressed in D.96-09-045. Our proceeding in A.99-03-049 will enable us to evaluate the reasonableness and efficacy of PG&E's expenditures, both O&M and capital spending, focused specifically on reliability. It will provide important input for the 2002 General Rate Case we are ordering here PG&E cites as another major driver of increased capital spending system growth associated with a more robust economy, including increases in the number of customers as well as system load. Most parties concede that there is a causative link between growth-related demand on the system and the need for capital additions to accommodate that growth. Even though Enron witness Weisenmiller believes that customer growth does not correlate to a need for increased revenue requirements, and that as a matter of policy we should require that customer growth effects be offset by actual or targeted productivity gains, we are persuaded that it is appropriate to recognize and make reasonable allowance for customer and load growth in this proceeding. We note that system-wide load growth in the 1996-1998 period exceeded that which occurred from 1993 to 1995, and customer growth has continued, if more moderately than a decade ago. It is reasonable to expect that PG&E needs to spend more during this GRC cycle in response to customer and load growth than it did in the previous GRC cycle.

There are, however, indications that PG&E may have overstated the impact of economic recovery on its growth-related investment needs. Customer growth was somewhat higher in the late 1980s and early 1990s, the last time PG&E's distribution capital spending was of a magnitude similar to what it is proposing in this GRC. From 1989 to 1992 the number of new customers averaged 70,796; the average for 1997 through 1999 was 52,634. TURN's regression analysis of 20 years of data suggests that PG&E's requested capital spending for the 1997-1999 time period is substantially greater (about $650 million according to the model results) than what would be predicted from PG&E's historical capital spending patterns, taking into account customer growth and the size of the system, although it drastically oversimplifies the different economic circumstances of the mid-1990s.

We do not endorse each of the criticisms listed above which were leveled at the PG&E forecast by the opposing parties. For example, PG&E's failure to consider the potential impacts of the Asian economic situation in its analysis does not strike us as a fatal flaw. Economic forecasting is inexact, and it seems prudent for PG&E to plan its distribution system in this GRC cycle with the assumption that the northern California economy might not be substantially impacted by the Asian crisis in respects that are relevant to distribution system growth. Also, parties who claim that the level of PG&E's capital spending is unprecedented, without reference to customer growth, may have overlooked the fact that when adjustments are made for inflation, PG&E spent more on distribution projects in 1989 than it did in 1997. In addition, despite remaining uncertainty about the difference between data reported by PG&E to FERC and data used by PG&E in its analysis of substation utilization, it appears that at least through 1997, PG&E's substation utilization factor was in line with long-standing, if outdated, utility industry standards.[23]

Nevertheless, we think that parties have raised substantial doubts about PG&E's requested capital spending level in addition to the reliability and growth

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[23] The record (Exhibit 193) discloses that in the face of technology improvement, and now competition, traditional utility industry practice which centered on 70% peak transformer loading is steadily becoming obsolete in favor of higher loading approaching 100% and even greater. Even when emergency loading policies are in place, the underlying report suggests that utilization factors of 85% to 90% are feasible.

issues discussed above. A good example is PG&E's spending on emergency projects. In a major departure from its practice of the previous nine years, when it spent less than $1 million in total for emergency capacity projects, PG&E spent $37 million on such projects in 1997 alone. It seeks approval for $55 million in emergency capital additions for the three years at issue in this GRC. PG&E has not demonstrated that such a dramatic and costly change in the application of emergency planning criteria that existed before 1997 is justified. Even when the criteria were finally invoked in 1997 after years of near-neglect, they were not fully applied, as evidenced by PG&E's failure to analyze the benefit-cost ratios of alternative actions. PG&E's spending on emergency capacity projects will yield improved reliability levels, but it is also consistent with the allegation that PG&E has may have installed distribution capacity before it is needed, if it is needed at all.

We share several other concerns that were raised by the opposing parties. The installation of 1,300 MW of capacity in 1997 is not explained by the rate of customer growth at that time. Peak loads in a significant minority of DPAs are well below capacity, and there is a history of PG&E overestimating capacity needs in a majority of DPA forecasts. Moreover, PG&E's temperature adjustments have been based on statistical methods which lack testing for statistical significance. PG&E's trend line adjustments create an upward bias in load forecasts, and in certain cases the adjustments were applied incorrectly. PG&E also included block load additions in trend line forecasts, creating an upward bias towards capacity additions. Evidence that PG&E would likely spend $140 million less on distribution investments in 1998 than it has requested in this GRC, and that it could spend up to $90 million less than its request for 1999, also supports the contention that PG&E can provide adequate service with a smaller level of distribution investments. PG&E's claim that it conducted a comprehensive bottoms up / top down forecasting effort appears to be overstated with respect to projects under $1 million, yet those projects account for much most of the estimated capital spending.

Thus, PG&E used distribution system planning methods that favored installation of new capacity, gave less attention to potentially more cost-effective alternatives to new capacity, and in some cases failed to apply its own planning criteria. Even though there is evidence that PG&E's substation utilization has been in line with, and possibly greater than, traditional utility industry practice, there is countervailing evidence that PG&E's planning processes were biased towards installation of more capacity than is needed, or making installations earlier than needed.

The magnitude of PG&E's proposed increase in capital spending must be understood in light the company's heightened awareness of system needs in the wake of the 1995 storms, the need to maintain historical reliability levels and meet other regulatory requirements, system growth, or the ability to respond to requests of others in accordance with tariff rules. Further understanding comes with the recognition that PG&E's forecast of capital spending was developed under a policy of making significant improvements in the reliability of the system, at a time when Section 368(e) funds were available, PBR regulation loomed near, and it was becoming more apparent that competitive forces may be making inroads into the distribution services industry. Despite the expertise behind it, we are not completely satisfied with the process used by PG&E and the resulting estimates of capital expenditures which it has included in its GRC request. Forecasting mistakes that were acknowledged by PG&E (for example, PG&E mistakenly categorized projects as over $1 million, and it failed to include the labor component of purchased meters) only add to our discomfort with its process.

PG&E has in effect presented us with what can best be described as a cost-plus budget that comports with the legislative requirement that utilities provide adequate service, but that may not reflect sufficient attention to the accompanying requirement that such service be provided at reasonable rates. Increases in distribution capital spending are justified to accommodate customer and load growth. We are not prepared to make significant reductions to PG&E's request at this time, but the concerns alluded to above compel us to provide for a means of limiting the possible effect of forecast error and upward bias in planning and construction criteria. We are mindful of the distinction between prospective approval of a test year capital spending budget and retrospective disallowance of recorded expenditures. We will exercise no presumption as to reasonableness, or lack thereof, with respect to expenditures already made in 1997 and 1998 for used and useful capital projects, although we note that the investigation into the expenditure of section 368(e) funds may examine reasonableness of the capital portion of that spending. Before determining the reasonable level of capital expenditures to be included in rates, we evaluate the other parties' forecast recommendations.

7.3.3.3 ORA's Forecast and Recommendations

ORA did not independently evaluate individual projects or categories of expenditures, with the limited exception of its analysis and recommendation for structurally overloaded distribution poles. ORA developed a forecast of gross plant additions by performing a regression analysis of recorded data from 1986 through 1996. In ORA's analysis, the dependent variable, gross plant additions, was regressed against the number of new customers, the average number of customers, total plant in service, and total sales in MWh. Based on this analysis, ORA recommends total additions for 1997 through 1999 of $1.25 billion. ORA believes that its forecast is consistent with PG&E's past expenditures, and notes that the data include expenditures made during storms that occurred in 1986 and 1995. ORA concludes that its analysis shows that PG&E's request is excessive.

ORA also recommends that PG&E's capital additions for 1995 and 1996 be made subject to reasonableness review. ORA notes that PG&E has an incentive to add projects to its plant that may enhance its competitive advantage. ORA was unable to resolve a discrepancy of $129.5 million between the recorded 1995 plant additions listed in FERC Form 1 and the amount provided to ORA by PG&E. ORA also recommends that 1996 recorded plant be adjusted by $88.7 million, which is the difference between 1996 recorded expenditures and the authorized level for 1996, pending completion of the review. ORA proposes that the review be conducted in Phase 2 of this GRC.

PG&E faults ORA's forecast as being disconnected from the current economic conditions and regulatory and legal requirements that PG&E must meet. PG&E also faults ORA's regression analyses and ORA's disregard of PG&E's forecast data. PG&E notes that ORA's forecast would have the Commission adopt a 1999 rate base that is barely above PG&E's recorded plant balance at the end of 1997.

Discussion

We find that PG&E has raised valid criticisms about technical aspects of ORA's regression analysis. The model's relatively small number of data points and large number of parameter estimates, and the presence of serial correlation, indicate the model is not robust. The analysis appears to confuse correlation with causality. The model's estimated inverse relationship between capital spending and sales is counterintuitive, since it suggests PG&E should reduce plant additions in response to increased sales. The model also indicates that increases in total plant additions should trigger reductions in capital spending in future years, a relationship that again appears to be counterintuitive.

We are not persuaded that ORA's regression model is sufficiently robust and technically sound to stand as the sole basis for forecasting PG&E's reasonable capital spending needs for this GRC. Still, it stands as additional evidence that PG&E's capital spending which is at issue in this GRC cycle, beginning in 1997, is substantially greater than what would be predicted on the basis of the company's historical capital spending, taking into account expenditure drivers such as customer growth.

We will not approve ORA's recommendations for reasonableness reviews of PG&E's 1995 and 1996 distribution capital spending. ORA has not demonstrated that such review is necessary or appropriate. Moreover, ORA's recommendation for consideration of this issue in the second phase of this GRC is procedurally defective, since that proceeding is reserved for consideration of marginal cost, revenue allocation, and rate design issues.

Consistent with our earlier determination regarding the costs associated with premature replacement of wood poles due to structural overloading in violation of GO 95 by PG&E and / or its joint users, we adopt ORA's recommendation to disallow $10.194 million in 1998 distribution plant.

7.3.3.4 TURN's Alternative Recommendation

If we do not adopt ORA's forecast of gross additions, TURN recommends that we reduce PG&E's estimated capital additions by $350 million. TURN originally recommended reductions of $410 million, but PG&E subsequently accepted TURN's recommendations for reductions in MWC 16 to reflect new line extension tariff rules effective in July 1998, and in MWC 30 to reflect expected expenditures based on historical levels. The combined adjustment agreed to by

PG&E for 1998 is $24,277,000 and for 1999 is $35,964,000, or a total of $60,241,000. With the removal of these areas of agreement, the components of TURN's recommended reductions are as follows:

TURN's Recommended Capital Spending Reductions

Description of Project/Category	Amount (Millions)
All distribution projects justified solely on the basis of emergency criteria where capacity is not needed to serve normal loads until after 1999. Includes disallowances of 1997 spending.	$55
Fifteen percent of named projects for 1998 and 1999 in MWC 06 to reflect installation of capacity before it is used and useful, due to forecasting errors at the DPA level.	$85
Contingency funds for "other projects" added to MWC 06 and MWC 08 in PG&E's March 1998 update and May 1998 workpapers.	$90
Adjustment to MWC 16 (New Business) for consistency with PG&E's sales forecast and to reflect reductions in unit costs included in internal documents but not in the GRC filing.	$56
Adjustments to Work Required by Others (MWC 10, $20 million) and Emergency Response (MWC 17, $40 million) for work identified but unlikely to be spent.	$60
Adjustment to reduce backlog of meters (MWC 25), reflecting reductions in PG&E's 1998 and 1999 spending by amount by which PG&E increased 1997 spending above projections.	$ 4

PG&E acknowledges that unlike other parties, TURN undertook a detailed analysis of individual projects and categories of spending. Still, PG&E faults TURN's analysis and contests each of the reductions shown in the foregoing table.

Discussion

Unlike ORA's and Enron's forecast approaches, TURN's alternative recommendation considers detailed, project-specific expenditures in two ways.

First, by recommending disallowances and reductions of the amounts forecast by PG&E, TURN implicitly accepts PG&E's detailed analysis as the starting point for its own analysis. More importantly, TURN's recommendations are based on detailed, project-specific analyses of the methods and procedures used by PG&E in developing its forecast.

As a preliminary matter, we note that even though TURN witness Marcus is not an experienced electric distribution system planner, he is well qualified to review PG&E's showing, conduct discovery, analyze data given to him by PG&E and data available from other sources, make judgments about the reasonableness of PG&E's proposed and forecast distribution capital spending, and make recommendations to the Commission based on such analysis and judgment. We reject PG&E's suggestion to the contrary. If Marcus lacks full understanding of "sound engineering practice in the emergency capacity area" as claimed by PG&E (in its reply brief at p. 79), his expertise in the area of economics, which PG&E acknowledges, compensates. Indeed, given PG&E's inattention to economic analysis in the development of its capital spending plan, Marcus brings a useful and important perspective to the development of a reliable forecast of PG&E's spending needs, one that is consistent with the framework of adequate service at reasonable rates. We will give his testimony appropriate weight.

Also, in view of the fact that PG&E identified 200 individual projects (although it deleted several during the course of this GRC), we find that it is permissible for TURN to have reviewed a sample of the projects and to have developed a total disallowance recommendation by extrapolating the results of its project specific analysis to PG&E's total capital spending. By casting doubt on the reasonableness of a sampling of projects, TURN may cast doubt on all of the projects reflected in PG&E's requested capital spending level. We address this concern by providing for an audit of 1999 capital spending by the Energy

Division that will enable us to determine with a degree of specificity how PG&E's capital spending has in fact been managed during a recent and presumably normal year.

We have already addressed several of PG&E's objections to TURN's analyses and recommendations. We address the remaining objections of PG&E in the following discussion of TURN's alternative proposal.

First, PG&E asserts that TURN drew inaccurate conclusions regarding the need for substation capacity projects to arrive at $140 million in recommended disallowances. PG&E claims that TURN's review is flawed because TURN failed to consider PG&E's "state-of-the-art" substation transformer utilization program. We agree, on the basis that the engineering judgement of PG&E's witnesses provides a stronger basis for determining need for capacity than the economist's agnosticism.

Second, TURN recommends disallowances of $90 million associated with contingency funds for projects of less than $1 million in MWC 06 and MWC 08. TURN witness Marcus explains his recommendation for MWC 06 as follows, later noting that his recommendation for MWC 08 is based on similar reasons:

> "Between the March update and the May update, PG&E canceled $120 million in specific projects. About half of those specific projects were highly questionable projects to spend millions of dollars to add emergency capacity. The first indication that these emergency capacity projects were canceled was when TURN sent a series of data requests regarding the basis for these projects. This fact strongly suggests that PG&E did not want to pursue controversial projects for which the Commission might deny funding.
>
> "However, PG&E still wanted the money without the controversy. So, after identifying a number of new specific projects, PG&E simply transferred the rest of the money into unidentified 'other projects.'
>
> * * *

> "Unidentified projects were about 20% of the total when the application was filed. They are now nearly 40% of the total. This change makes no sense. PG&E's plans should become more definite, not less definite, as time passes. Yet PG&E has adopted the attitude that the Commission should trust that it will spend the money it requested, spend it fast, and spend it prudently, if not on projects questioned by TURN, then on other supposedly worthy projects, even if it does not happen to know what those projects might be." (Exhibit 369, pp. 49-50.)

PG&E explains that it simply made an error in its March Update workpapers which inaccurately categorized projects as projects over $1 million when they should have been included in the "other projects" category, which encompasses all projects under $1 million. PG&E further explains that it refined its customer/load growth forecasts after the 1997 peak load had been more thoroughly analyzed. As a result of this analysis, PG&E reduced the number of planned projects greater than $1 million but also realized the need to upgrade distribution ties between substations and increase circuit capabilities, projects which are typically less than $1 million. We credit this testimony.

Third, PG&E disputes TURN's proposed $40 million disallowance associated with MWC 17 (Emergency Response). Emergency response work is performed when equipment fails suddenly due to damage from vehicles, trees, weather, animals, birds, and other reasons. PG&E projected a 1998 cost based on $3,400 per outage multiplied by an estimate of 15,589 outages plus an allowance of $5 million for substation failures. This yielded a total of $58 million. PG&E included an additional $25 million which, according to PG&E's rebuttal testimony, is managed centrally to accommodate major events and unusual events. TURN found that the base level of $3,400 per outage times the number of outages predicts actual 1996 spending of $55 million quite well, but notes that 1997 spending rose to $92.9 million with a smaller number of outages. TURN finds that the extra $25 million is not required to be spent on a consistent basis, and recommends that PG&E's GRC primary spending requests of $82.6 million for 1998 and $76.7 million for 1999 be reduced to $65 million in 1998 and $63 million in 1999. TURN notes that its recommendation results in reductions in authorized spending of $21.6 million in 1998 and $19.7 million in 1999.

PG&E notes that its forecast for MWC-17 in 1998 reflects a 10.8% decrease from 1997 recorded and the 1999 forecast reflects a 16.1% decrease from 1997. PG&E believes that this shows its forecast is appropriate. However, as TURN points out, PG&E spent almost $93 million in 1997 after spending $55 million in 1996. PG&E's has not shown that its proposed spending for 1998 and 1999 is reasonable by virtue of reference to the high level of spending in 1997, nor has it otherwise provided adequate justification for the increased level of spending. Nevertheless, we will not disallow capital expenditures made specifically for reliability recorded in 1997 and 1998 simply on the basis of a claim of an unpredictable (or unpredicted) spending pattern. We have no basis for further reducing PG&E's estimate on this record. The authorized spending for 1999 will be reduced to reflect TURN's concern, subject to the audit of 1999 capital spending.

Fourth, TURN recommends a reduction of $60 million associated with new business ($56 million) and meters ($4 million). The former reduction reflects TURN's adjustment of the number of added customers for consistency with PG&E's forecast of customers in the sales forecast as well as different unit costs. PG&E draws a distinction between the number of customers used in the sales forecast for estimating revenue at present rates and the number of customers used for estimating capital costs of connecting new customers. PG&E maintains that the former, which is developed by counting the number of new bills in a year, cannot be used for the latter purpose. PG&E notes that several new connections may be associated with a single bill. Further, the composition, load characteristics and locations of new customers are not captured in the "net new customers" used for the sales forecast, although these are factors that will drive new capital investment. We find TURN's position that there should be consistency between forecasts for sales estimates and forecasts for capital additions estimates to be implausible.

We will not adopt TURN's adjustment of $4 million for purchased meters. TURN's adjustment was based on the difference between forecasted and recorded 1997 additions. PG&E later determined that the forecast included only the material cost of meters and failed to include installation labor and other charges. PG&E's forecast is in line with historical additions since 1994.

Fifth, TURN recommends a reduction of $20 million associated with MWC 10, Work at the Request of Others. TURN calculated the inflation-adjusted average for 1989 through 1997, excluding the outlier year 1995. TURN argues that costs in this category have been quite variable, which is to be expected as these costs result from such causes as new development resulting in street and highway relocation and discretionary projects. PG&E claims that its use of 1997 recorded values is indicative of economic conditions affecting cities and counties. This is a more accurate represenatation of conditions in 1999 than an average that includes a number of years of serious recession.

We find that with the exceptions of Purchased Meters, and additional adjustments to MWC 06 discussed below, the components of TURN's recommended capital spending reduction of $350 million are not fully supported by the record. Reductions in authorized Test Year capital spending are allowed to the extent discussed.

7.3.3.5 Enron's Forecast and Recommendations

Enron recommends adoption of a five-year average of recorded data (1992-1996) for net additions. Enron contends that its forecast level of additions, which is similar in magnitude to ORA's forecast recommendation, is particularly appropriate given the combination of PG&E's limited justification for its massive increase and PG&E's motives as a result of the super A-J effect to achieve a large increase. Enron asserts that compared to PG&E's use of 1997 recorded expenditures, its averaging approach better represents the variability of PG&E's prior expenditures, is consistent with the approach adopted for plant growth for attrition in prior GRCs, and will alleviate concerns about the use of the results of this proceeding in the future for PBR or attrition adjustments.

PG&E's position on Enron's approach is similar to that which it took with respect to ORA's and other parties' recommendations. In particular, PG&E contends that Enron's method of averaging historical data illustrates a lack of understanding of the requirements of PG&E's electric distribution system, and reflects no program-by-program or other detailed analysis.

Discussion

Enron's use of averaging results in a forecast that recognizes the variability in PG&E's capital spending over time. It is an accurate reflection of historical capital expenditure patterns by PG&E. In addition, the results of Enron's computation corroborate the view that PG&E is seeking approval of dramatic increases in electric distribution capital spending above the levels of recent years.

However, we are concerned that Enron's approach gives insufficient weight to key drivers of capital expenditures that are likely to be at work in the period covered in this GRC cycle. Unlike regression analyses offered in the record by other parties, simple averaging can give no weight to new information about driving factors such as customer growth. It also fails to consider current, project-specific needs of the distribution system. Moreover, we are concerned that the data points selected by Enron give too much weight to spending patterns during the economic downturn of the early to mid 1990's. We conclude that Enron's forecast is not sufficiently representative of current spending needs, and cannot serve as the sole basis for determining those needs in this GRC.

7.3.3.6 Conclusion - Electric Distribution Capital

In his rebuttal testimony, PG&E witness Pearson states that if the capital spending recommendations of ORA and other opposing parties are adopted, PG&E may not be able to meet statutorily required levels of reliability, or the level of reliability customers expect. It would be appropriate for utility management and regulator alike to simply heed Pearson's warning without further analysis, and approve the full spending plan that he proposes. After all, nobody wants to be responsible, directly or indirectly, even in part, for imposing on customers and the public generally the hardships of outages or other consequences of reduced expenditure levels that do not fully incorporate the judgment of experienced system operators. However, we would shirk our statutory duty if we simply endorsed a "reliability-at-any cost" position, and focused only on adequate service, without giving due consideration and weight to the requirement for reasonable rates. However, the record is not sufficient for us to make a reasoned judgement as to the precise relationship between reliability and cost. If we must err, we choose to err on the side of reliability in terms of authorizing spending.

Consistent with our earlier determination that PG&E has not justified its full capital spending request, we find that PG&E's request of $2.38 billion in capital additions should be reduced to reflect certain of TURN's proposed reductions with an adjustment to reflect PG&E's position on Purchased Meters (MWC 25) and a further modification to TURN's recommendation for MWC 06.

As noted earlier, TURN recommends a reduction of $85 million to MWC 06 to reflect 15% of named projects being installed in 1998 and 1999, before they were used and useful. We will not disallow 1998 expenditures for used and useful facilities. Exhibit 379 shows that TURN derived the $85 million figure by multiplying the total figures associated with MWC 06 for 1998 and 1999 by 15%. While we accept TURN's 15% reduction factor and the principle of extrapolation as reasonable, we believe that it is also appropriate to make an adjustment to TURN's reduction. As shown in Table H of its rebuttal testimony, PG&E estimated total MWC 06 spending of $171 million in 1998 and $124 million in 1999, or a combined total of $295 million for the two years. TURN also recommended, and we have approved, MWC 06 reductions. The adopted 15% reduction for 1999 is $13.3 million (($124 million - $35.1 million) x .15).

Adopted Electric Distribution
Plant Additions
1997-1999 (in Millions)

	1997	1998	1999	3-Year
PG&E's Requested Additions	$745.0	$843.0	$792.0	$2,380.0
Adopted Reductions - TURN				
Emergency Projects			$ 5.0	$ 5.0
MWC 06 - 15% Named Projects			$ 13.3	$ 13.3
MWC 06 - Other Projects			$ 35.1	$ 35.1
MWC 08 - Other Projects			$ 2.1	$ 9.6
MWC 17 – Outage Response			$ 19.7	$ 19.7
ORA Pole Replacement		$ 10.2		
Total Adopted Reductions			$ 75.2	$ 75.2
Adopted Plant Additions	$745.0	$832.8	$716.8	$2,294.6

CFBF proposes that PG&E be required to provide ongoing tracking of all of its significant capital investment programs. We approve a variant of this proposal. In the event of another GRC, the burden will again be on PG&E to show that its requested capital spending is reasonable. However, given the reservations we expressedabove concerning PG&E's budgeting and incentives for upward bias in the forecast, we direct the Energy Division to conduct an audit of 1999 recorded captial expenditures. This audit should examine both the level of actual (as compared with authorized) capital spending and evaluate the reasonableness of expenditures on the basis both of engineering and economic (cost effectiveness) judgement. The results of this audit and of the 368(e) investigation may be used in the new GRC and in any attrition filing for 2001 to help us and PG&E refine procedures for estimating and authorizing distribution capital spending for the future. The audit will establish an accurate year end 1999 electric distribution ratebase. It should commence with a year end 1998 ratebase, and examine actual capital spending in 1999. If there has been a variance between 1998 forecasts and actual spending for 1998, it will not persist beyond the conclusion of the audit. The audit should also examine two policy issues that have animated much of the dispute in this case on the issue of the reasonableness of PG&E's capital spending. The first is the "lumpiness" of distribution investment; that is the occurrence of distribution investments that are made for various reasons in advance of immediate need. The second is the nexus between distribution capital investments and sustained or improved reliability. On the basis of this audit we hope to have a sound basis to directly address these important issues going forward.

CAL-SLA was at first concerned that PG&E is not retiring plant from rate base in the case of streetlight sales to municipal agencies. In particular, it was unclear to CAL-SLA if PG&E is retiring the plant for the Alameda County sale. After cross-examination, however, CAL-SLA was satisfied that PG&E accounted for the retirement.

8. Gas Revenues, Expenses, and Capital

8.1 Revenues

8.1.1 Customers and Sales

In its March Update, PG&E provided a gas throughput forecast based on estimates included in joint testimony in PG&E's most recent Biennial Cost Allocation Proceeding (BCAP). The forecast, which was supported by all active parties to the BCAP, was adopted by the Commission in D.98-06-073. PG&E and ORA recommend that this forecast, which is set forth in Exhibit 20 (in Table 4A-IR), be adopted in this GRC proceeding. No party opposes this recommendation, which we hereby adopt as reasonable.

8.1.2 Revenues at Present Rates

As shown in the comparison exhibit, PG&E and ORA agree on the forecast of billed revenues at present rates based on the customer and sales forecast. The total Gas Department revenue at present rates forecast, including gas transmission and storage, is $1.783 billion. This total consists of $700 million non-general revenue and $1.083 billion GRC revenue. Excluding Gas Accord functions, the agreed upon forecast is of $814 million in GRC revenue.

FEA proposes two adjustments to gas revenues similar to those it proposed for electric revenues (see Section 7.1.2 of this decision). The first adjustment reflects a correction to the amounts used by PG&E in its original and March Update filings and would reduce Other Gas Revenue by $809,000. The second adjustment proposed by FEA increases Gas Operating Revenues by $2.72 million. It is made to reflect adjustments proposed by ORA in its Report on the Results of Examination.

As noted earlier, PG&E updated its GRC proposal in the comparison exhibit to reflect positions of record, including those set forth in rebuttal testimony and changes made by witnesses during hearings. FEA has not demonstrated that the changes set forth in its testimony are required in connection with the final PG&E position as set forth in the comparison exhibit. We adopt PG&E's present rate revenue forecast as reasonable.

8.2 Expenses

8.2.1 Production

PG&E is requesting $9.7 million in production expenses for 1999. ORA does not take issue with this request, since the Gas Accord sets PG&E’s gas production rates for 1999 and until 2002. Enron disputes PG&E’s inclusion in revenue requirements of $2.4 million of gas production expenses associated with the cost of procuring gas for bundled customers. Enron contends that gas procurement is a competitive service that does not belong in distribution revenue requirement.

As PG&E points out, it is obligated to provide procurement services to core and core subscription customers at tariffed rates. We are satisfied that PG&E’s proposal for including procurement costs in revenue requirements is consistent with our BCAP ratesetting process, in which these procurements costs are subtracted from the distribution revenue requirement, and included in procurement rates as a brokerage fee. This is also consistent with Chapter 2.2 of the Public Utilities Act , Public Utilities Code Sections 328 through 328.2, added by Chapter 909, Stats. 1999 (AB 1421, Rod Wright), effective on January 1, 2000. This statute provides for inclusion of costs related to procurement in basic bundled gas service, consistent withour current practice.

PG&E performs R&D work in targeted areas of its California Gas Transmission organization. The objectives of these R&D activities are to increase the operating life, reduce the costs, and improve the operating efficiency and safety of PG&E's gas production, storage, and transmission systems. Enron disputes the inclusion of $319,000 for gas production R&D expenses and $1.8 million for gas distribution R&D expenses. More generally, it disputes the inclusion of R&D expenses on the grounds that R&D will better position PG&E in a competitive environment and should therefore be paid by shareholders.

We are persuaded that gas R&D activities that PG&E has included in this GRC are consistent with promotion of efficiency and safety for ongoing regulated operations. Enron has not demonstrated that PG&E's request harms current or future competition. Accordingly, we adopt PG&E's requested production expenses.

8.2.2 Storage

The Gas Accord sets PG&E's gas storage rates for 1999 and until 2002. For cost allocation, PG&E presented an estimate of $8.6 million for storage expenses. No parties have taken issue with this estimate, which we adopt for allocation purposes.

8.2.3 Transmission

The Gas Accord sets PG&E's gas transmission rates for 1999 and until 2002. For cost allocation, PG&E presented an estimate of $43.5 million for transmission expenses (including Line 401). With the exception of Enron's position on R&D expenses, no parties have taken issue with this estimate, which we adopt for allocation purposes. We note that PG&E agrees that these targeted gas R&D costs should be unbundled to the gas transmission and storage UCC, and that since the Gas Accord sets gas transmission and storage rates, these R&D costs will not have a direct affect on PG&E's rates.

8.2.4 Distribution

8.2.4.1 Introduction

Gas distribution expenses include the labor, materials and services and other related costs necessary to operate and maintain PG&E's system of mains, services, district regulators, valves, and domestic meters and regulators. They also include the costs associated with work on customer premises and equipment. Operations expenses are recorded in FERC Accounts 870-881 while maintenance expenses are recorded in Accounts 885-894.

PG&E has twice revised its proposal for gas distribution O&M expenses. PG&E now requests $91.7 million (in 1996 dollars) in operation expense and $50.2 million in maintenance expenses for a total of $141.9 million O&M expenses for test year 1999. In the 1996 GRC, the Commission adopted total operations expense of $84.8 million and total maintenance expense of $34.9 million, or a total O&M expense of $119.7 million. In general, PG&E justifies its requested increases in gas distribution O&M by reference to its implementation of a new business system in 1996 and an increase in economic activity between 1993 and 1996.

ORA recommends that we authorize $82.3 million in operations expense and $43.2 million in maintenance expenses for a total of $125.5 million in O&M expenses. Enron recommends that we authorize $84.4 million in operating expense and $43.1 million in maintenance expenses for a total of $127.5 million O&M expenses. TURN does not make a comprehensive proposal for gas distribution O&M, but it does raise issues and offers specific recommendations pertaining to PG&E's Gas Pipeline Replacement Program (GPRP).

As we found with respect to the parties' differences regarding electric distribution O&M, the differences here are due, among other things, to differences in forecasting methodology. Before addressing methodology issues, we first address specific expense issues raised by TURN and ORA. We addressed Enron's recommendation for distribution R&D expenses in Section 8.2.1.

8.2.4.2 GPRP Expenses

The GPRP was established in 1985 to replace aging gas pipe throughout PG&E's system. In 1994, PG&E implemented an accounting change that treated as capital costs certain GPRP costs that had previously been expensed. This was not disclosed to the Commission in the last GRC, although TURN contends it should have been. The accounting policy was issued in September 1994, before the 1996 GRC application was filed and litigated. The Commission adopted ORA's forecast of $3 million in GPRP expenses even though the underlying costs were being capitalized.

While TURN does not oppose such an accounting change on a prospective basis, it contends that PG&E's "manipulation of accounting practices between rate cases" resulted in a double billing of ratepayers because "PG&E requested and received rate recovery in the 1996 [test year] GRC for GPRP expenses in Accounts 878 and 879 that PG&E knew at the time it was capitalizing, not expensing." (Exhibit 369, pp. 7-8.) TURN contends that from 1996 through 1998, "PG&E received $2,990,000 in each year in expense that it would not have received in rates had it provided complete and truthful information that it knew at the time to the Commission." (*Id.*, p. 9.) TURN recommends that $1.3 million be removed from the 1997 opening plant balance. TURN also recommends that a 1999 rate offset of $10.7 million for 1996-1998 overcharges be ordered. This amount represents annual expenses of $2,990,000 plus interest at PG&E's authorized rate of return. TURN further recommends that $2 million in GPRP expenses sought by PG&E in this GRC be denied as unsubstantiated.

PG&E admits that the 1996 GRC forecast included expenses that were more properly forecast as capital, and that it made "an unintentional forecasting error." Nevertheless, PG&E contests TURN's recommended offset of $10.7 million on two grounds. First, PG&E contends, at the time the GPRP expense forecasts were developed and testimony was prepared for the 1996 GRC, the responsible witnesses did not know about the changed accounting practices. Second, PG&E contends that TURN's proposal for a rate refund constitutes impermissible retroactive ratemaking.

Discussion

Although PG&E admits providing erroneous information to the Commission, it attempts to absolve itself of responsibility by claiming that certain witnesses were unaware of the error at the time they prepared their testimony. However, even if the witnesses were unaware of the accounting change, and remained so throughout the course of the 1996 GRC, that would be of little import. When PG&E submits an application to the Commission, it assumes full responsibility for the total presentation it makes to the Commission. PG&E cannot escape responsibility for any misleading of the Commission that occurs when it mischaracterizes the accounting treatment accorded certain costs , even if individual witnesses are acting in good faith. As TURN points out, the fact that PG&E's witnesses may have been unaware of the accounting change is precisely at issue: "Somebody at 77 Beale Street had to have known that the change in accounting practice had been made and that the change would affect the treatment of costs included in the 1996 GRC." (TURN Opening Brief, p. 44.) We remind PG&E and all parties that Rule 1 of the Rules of Practice and Procedure applies to any person who signs a pleading or brief, enters an appearance, or transacts business with the Commission. It is in no way limited to witnesses. The purpose of Rule 1 is to remind participants in our proceedings that they have a meaningful and enforceable obligation to assist the commission in advancing the public interest.

PG&E asserts that the error is of little consequence since the Commission adopted ORA's forecast of $3 million in GPRP expenses and not its own, much higher, expense forecast. However, the fact that the Commission adopted a lower forecast does not change the fundamental problem of potential double billing of ratepayers; it only reduces the dollars at issue. It is clear that the company has benefited from its admitted error. It is also clear that this was not a routine forecasting error, akin to miscalculating the impact of economic developments on customer growth. To the contrary, PG&E either knew or should have known that its proposal in the 1996 GRC was inconsistent with its internal accounting policy and could result in excess recovery of GPRP costs.

PG&E claims that the error was unintentional. We do not accept the proposition that it would be acceptable to double bill ratepayers as long as the company's witnesses meant well. Utility applicants have, and must diligently comply with, an obligation to affirmatively assist us and our staff in accurately portraying their finances for ratemaking purposes. As explained above, utility applicants effectively control information about costs and processes. We reiterate that we expect PG&E to honor this obligation.

Nevertheless, we agree with PG&E that TURN's recommendation for a rate offset should be rejected in this proceeding. The proposal attempts to replicate what would have occurred if PG&E had not provided erroneous information in 1996. Given that the Commission did not credit PG&E's 1996 proposed GPRP expense, it is difficult to determine the real impact on consumer rates during the 1996-1998 period, if any. This is because if any double billing occurred it could have been corrected by disregarding the incremental capital investment and associated revenue requirement and fully recognizing the expense, as proposed, as we have done for future ratemaking purposes in Section 8.3.4.2.2. We will decline to speculate on whether this amount would have been material.

Although TURN did not uncover the accounting change and its implications until after the record of the 1996 GRC was closed, it could have brought it to the Commission's attention by way of complaint. Public Utilities Code Section 1702 provides in pertinent part:

> 1702. Complaint may be made by the commission on its own motion or by any corporation or person, ... by written petition or complaint, setting forth any act or thing done or omitted to be done by any public utility, including any rule or charge heretofore established or fixed by or for any public utility, in violation or claimed to be in violation, of any provision of law or of any order or rule of the commission. ….

This procedure is generally available to remedy an alleged violation of a Commission rule or a provision of the Public Utilities Code, and may be available with respect to this matter in which the Commission's process is allegedly abused.[24] We will not enter the realm of retroactive ratemaking by using this GRC to base prospective general rates on past activities alleged to have been unreasonable. To do so would be inconsistent with forecast test year ratemaking.

We now turn to forward-looking expenses at issue in this GRC. As TURN points out, PG&E requested $2.491 million (later reduced to $2.028 million) in GPRP expenses. Yet, TURN notes, PG&E recorded a total of $471,000 in GPRP expense in the last two recorded years, including none at all in 1997. TURN

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[24] But see Public Utilities Code Section 734.

recommends adoption of a forecast of $471,000 if PG&E's forecasting methodology is adopted. We note that PG&E now agrees to TURN's proposed reduction of expenses, and, as reflected in the comparison exhibit, has removed the disputed amount for GPRP expenses from its request.

If ORA's four-year average forecast is adopted, TURN recommends that base year 1993 estimates be adjusted downwards by $3.2 million. This would result in a reduction in ORA's forecast of one-fourth that amount, or $800,000. We note, however, that ORA's recommendations for four-year averaging apply only to maintenance accounts and to operation Account 875.

We consider TURN's recommendation for plant adjustments for GPRP costs in Section 8.3.4.2.

8.2.4.3 Combustion Appliance Safety (CAS) Testing

CAS tests are used to detect carbon monoxide and other combustion byproducts in some DSM programs before certain energy efficiency measures are installed. The Commission ruled in Resolution E-3515 dated December 16, 1997 that carbon monoxide testing cost recovery would not come from DSM program budgets. As a result of this resolution, which was issued after PG&E prepared this GRC application, PG&E requested in its March Update that $5 million in CAS testing expenses be included in Account 879. PG&E witness Ridings later reduced this to $3.7 million.

ORA disputes this recommendation on several grounds. ORA contends that PG&E failed to demonstrate that its cost estimate is reasonable, that the expenditures are cost effective, and that they are not already included in the forecast.

Discussion

PG&E has provided adequate support for its estimate of $3.7 million for CAS testing. It appears to reflect a forecast of the number of tests and the unit cost for the test. PG&E did indicate in a data request response to ORA that it expected to test 33,500 homes in 1998 at a cost of $1.8 million. A modest expansion of this program for 1999 appears reasonable. Further expansion in 2000 and beyond appears inevitable in light of the Legislature's enactment of AB 1421.[25]

In the face of an argument that it has not demonstrated that the CAS testing program is more cost effective than the alternative of using carbon monoxide testing devices in combination with the continuation of its routine carbon monoxide testing, PG&E asserts that CAS testing is the better approach to preventing carbon monoxide poisoning. It represents the "best practice" nationwide and is proactive because it attempts to eliminate the source of carbon monoxide rather than detect its presence. PG&E also believes that this is a safety issue that renders difficult if not impossible quantitative evaluation of the costs and benefits of CAS testing against those of the alternatives. We find these reasons persuasive. In public policy analysis, it is not uncommon to weigh the value of safety programs against their costs even though it sometimes requires making uncomfortable choices about the economic value of human life.   We decline to undertake such an analysis in this case, despite ORA's discomfort. The interest of ratepayers certainly encompasses this type of safety program.

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[25] Public Utilities Code Section 328.2 requires utilities to provide basic bundled gas service, including "after meter services." After meter services are expressly defined to include carbon monoxide investigation. (Public Utilities Code Section 328.1(c).)

We therefore grant the request.

8.2.4.4 Past Maintenance Practices

ORA consultant MHB found that for the eight-year period from 1987 to 1994, PG&E underspent adopted gas distribution maintenance expense levels by $55.2 million in 1996 dollars, or an average of $6.9 million per year. ORA also believes that external assessments and internal audits conducted by or for PG&E raise serious doubts about the effectiveness and efficiency of PG&E's past management of gas distribution system maintenance activities. These include the June 1993 report by Bain, and the August 1995 reports by Arthur Andersen and Black and Veatch, which were addressed earlier in this decision, and two 1997 internal audits.

ORA cites several findings from the Arthur Andersen report as exemplary of asserted failures in both corporate policy and resource allocation affecting gas distribution system maintenance:

> Gas and electric preventative maintenance is not sufficiently communicated as a key component of an efficient asset management plan and the opportunity it presents for increasing shareholder value.
>
> The frequency of reorganizations and personnel changes has had an unfavorable effect on organizational effectiveness, including the execution and continuity of gas and electric preventive maintenance programs. The result is a lack of clarity of responsibility and accountability.
>
> Key performance measures are not in place to adequately inform Customer Energy Services management and corporate senior management of gas and electric distribution system condition and effectiveness of preventive maintenance program.
>
> The link between the planning concepts of service reliability and the funding of preventive maintenance programs is not evident in either the planning phase or the resource allocation phase.

> Budget sources appear to be discretionary if programs are not mandated by external forces such as the Commission or the California Department of Forestry.
>
> Division preventive maintenance program expenditures are controllable costs allowing preventive maintenance resources to be managed to achieve overall division budget targets.
>
> Preventive maintenance programs are budget-driven, not service reliability-driven, which leads to deferring or eliminating the programs.
>
> Preventive maintenance programs appear to have been insufficiently funded.
>
> Current Performance Incentive Plan targets encourage employees to spend less than their amount of allocated dollars which increases the risk of deferring or discontinuing gas and electric preventive maintenance programs.

ORA finds that PG&E either did not conduct planned maintenance activities or deferred them to a later date. ORA concludes that actual maintenance expenditures for 1995, 1996, and 1997 may have partly been incurred to address remedial or corrective actions. ORA acknowledges that it was unable to quantify the impacted amounts.

PG&E responds that it has not deferred gas distribution maintenance in the past, and faults ORA's showing to the contrary. Moreover, PG&E denies that its 1996 and 1997 recorded gas distribution maintenance expenses reflect costs associated with deferred maintenance.

Discussion

While the $55 million cumulative difference between authorized and actual spending from 1987 to 1994 is not insubstantial, it is one-ninth the comparable underspending by PG&E for the electric distribution system during the same period. Even taking into account the larger scale of the electric distribution system operations, it is clear that PG&E was not underspending authorized amounts for gas system maintenance to the extent it was for the electric system. Moreover, as we noted earlier, the fact that a utility spent less than authorized amounts for a given activity does not, alone, demonstrate unreasonable practices. We do become concerned when there is a pattern of underspending over an extended period, i.e., several GRC cycles, particularly when there is other evidence that the utility's actual practices at the time of such underspending were deficient.

Since ORA relied on three of the same reports that supported its analysis of PG&E's electric distribution system maintenance practices, it is not surprising that ORA draws similar conclusions with respect to PG&E's past maintenance of its gas system. Indeed, many of the corporate policies and incentives for management action or inaction that led to PG&E's underspending and deferral of maintenance in the area of electric distribution system maintenance were applicable to the management and operation of the gas system. On balance, however, we find that ORA has not shown that PG&E's gas system maintenance practices were as problematic in scope or degree as those of the electric system.

Thus, while it was clear that for several years PG&E spent less than it reasonably should have in the maintenance of its electric distribution system, we are not prepared to draw a similar conclusion with respect to its gas system. We note that ORA has identified general deficiencies, not that any specific gas distribution maintenance practice was systematically deferred or performed inadequately by PG&E prior to 1996. We also note that the studies relied upon by ORA to draw the conclusion of deferred maintenance generally seem to have less harsh criticism of PG&E's gas system maintenance practices. At least with respect to compliance with the established standards, the Arthur Anderson report noted that the preventative maintenance process for the gas distribution system was generally well managed, and that PG&E divisions were in compliance. Of the two internal audit reports relied upon by ORA, to support its claim of deferred gas distribution maintenance, one dealt with implementation of a gas emergency plan and did not specifically relate to maintenance practices. The other was conducted in 1997, after the time during which ORA asserts maintenance was being deferred.

While we do not find that PG&E's past practices with respect to the gas system mirror those for the electric system, we do not discount the findings in the Bain, Arthur Andersen, and Black and Veatch reports with respect to gas maintenance practices. As ORA has demonstrated, PG&E expended funds to develop and implement corrective measures to address the deficiencies identified in the audits cited by ORA. While the amount of such funding was not quantified, it is apparent that an incremental amount of remedial gas system maintenance is reflected in 1996 recorded expenses relied upon by PG&E in its forecast.

8.2.4.5 Forecasting Methodology and Other Adjustments

PG&E estimated gas distribution expenses for the years 1997 through 1999 for each account by first establishing a base estimate using recorded, adjusted 1996 expenditures. The base estimate was adjusted to reflect changes in activity levels and the savings or costs associated with special projects or programs for the forecast years. For Accounts 878, 879, and 893, forecasts were developed in an aggregate for corresponding electric accounts as a result of the 1996 change in PG&E's accounting system.

For gas distribution operations expenses, other than for Account 875, ORA accepts PG&E's account-by-account estimates as a starting point, then makes adjustments to eliminate CAS testing expenses, and expenses associated with

PG&E's IT projects. For Account 875 (Measuring and Regulating Station-General), ORA uses a four-year average, resulting in a $0.11 million reduction to PG&E's estimate. For estimated test year gas distribution maintenance expenses, ORA uses a four-year average of PG&E's gas distribution maintenance expenses from 1993 through 1996 and takes the midpoint of this calculation and a bottom-up estimate of PG&E's spending needs. With respect to adjustments for IT projects, ORA recommends reductions of $1.4 million for the Work Management System, $3.96 million for the Field Automation System, and $1.22 million for the Facilities Information Database. Of this total IT reduction of $6.6 million, $5.6 million is removed from operations accounts and $960,000 is removed from maintenance accounts.

PG&E offers two reasons why it believes that ORA's four-year average does not provide a reasonable 1999 estimate for maintenance expenses. First, PG&E contends that because of its implementation of a new business system and accounting procedures in 1996, activities recorded in maintenance accounts prior to 1996 are not necessarily identical to the types of activities that are being recorded in the maintenance accounts now. Some expenses which were recorded in A&G accounts are now recorded in O&M accounts. Also, there has been a shifting of costs among some O&M accounts, so that some costs which were recorded in operations accounts, for example, may now be recorded in maintenance accounts. Second, PG&E contends, increased construction activity led to a 28% increase in "Mark and Locate" requests between 1992 and 1996 and there is an increase in the number of dig-ins and resultant damage to PG&E's gas distribution system. There were 1713 dig-in leaks in 1993, 1637 in 1994, 1,490 in 1995, 1,781 in 1996, and 1,927 in 1997. PG&E believes that because of this increase in activity, use of an average does not reasonably estimate what the costs were in 1996, or what they can be expected to be in 1999.

Enron uses a five-year average of PG&E's total O&M expenditures to develop an overall O&M forecast. Enron makes one adjustment to the average, a reduction of $17.6 million to reflect an "unexplained anomaly" in Account 879 (Customer Installation Expenses). Enron made this adjustment because expenses rose 68% ($17.6 million) between 1994 and 1995, and PG&E was unable to provide Enron with an explanation for the increase. Enron concluded that the increase was an anomaly which should not be reflected in rates.

While PG&E does not generally agree with averaging, it notes that the five-year average of gas distribution O&M expenditures is essentially equal to its own total O&M request. PG&E would not object to the result of adopting a five-year average of gas distribution O&M expenditures as PG&E's estimated gas distribution expenditures for 1999. PG&E does however object to Enron's adjustment of $17.6 million. Among other things, PG&E contends that if the $17.6 million adjustment is adopted, the adjustment should be made before an average is computed. PG&E believes that the resulting adjustment to the five-year average would be $3.5 million.

Discussion

On a constant dollar basis, PG&E's requested operations expense of $91.7 million exceeds the 1996 adopted maintenance expense of $84.8 million by more than 8%. PG&E's requested maintenance expense of $50.2 million exceeds the 1996 adopted maintenance expense of $34.9 million by nearly 44%. The total increase requested in gas distribution O&M expenses is $22.2 million, or more than 18%. Such large requested increases, particularly in the maintenance accounts, immediately call into question the methodology used to arrive at them. We note that PG&E has not demonstrated that customer expectations, reliability-related mandates of the Commission since the last GRC, or system growth account for the increases.

For gas distribution operations accounts, the primary issue is whether to use PG&E's approach of starting with 1996 recorded expenses or Enron's five-year averaging. Our major concern with Enron's approach is that calculating an average for all operations and all maintenance accounts combined is too far removed from our generally and historically favored approach of account-by-account analyses. While we do not find that Enron's approach is unreasonable, we believe that starting with PG&E's recorded operation expenses for 1996 and making appropriate adjustments, as ORA has done, is more likely to yield a reasonable estimate of PG&E's spending needs for 1999.

Accordingly, we adopt PG&E's estimates as the basis for forecasting gas distribution operating accounts. We also adopt ORA's use of a four-year average for Account 875, which results in a $0.11 million reduction to that account. ORA has shown that the history of that account is consistent with our guidelines for the application of averaging. PG&E states that it has installed a significant number of pressure monitoring devices connected to telecommunications systems, as well as additional Supervisory Control and Data Acquisition remote monitoring devices, and that the costs of operating these monitoring systems have increased Account 875 costs. However, as ORA points out, PG&E did not quantify the extent of the increase associated with these devices.

For gas distribution maintenance accounts, we find that ORA's use of forecasting based on averaging is preferable to PG&E's approach and should be adopted. ORA found significant fluctuations in maintenance expenses from 1993 to 1996, which favors the use of averaging under our established guidelines. As we have found, an increment of deferred maintenance expense is reflected in the 1996 recorded year that PG&E uses as the starting point for its forecast. An average of maintenance expenses incurred over a period of years is therefore more likely to predict actual needs going forward. There is no convincing evidence that PG&E's 1996 recorded expenses are a better predictor of test year spending needs than the four-year average proposed by ORA. Unlike PG&E's past electric distribution maintenance expenses, where we found that it would be inappropriate to use an average based on several years during which PG&E spent less than reasonable amounts on maintenance, we have not found that PG&E's gas system maintenance expenditures during the 1993 to 1996 period reflect inadequate or insufficient practices. In short, the circumstances of PG&E's historical gas maintenance practices are not the same as those of its electric system, and it is reasonable to give significant weight to PG&E's spending pattern prior to 1996.

PG&E's reasons for rejecting averaging are not persuasive. Growth in the gas distribution system has been a minimal 1.0% per year since 1993 as measured by the increases in miles of main or in number of services. PG&E's witness was unable to quantify the impact of economic growth on the maintenance expense level, and he appeared to acknowledge that, at least in part, additional costs attributable to growth would be offset by operating efficiencies and improved productivity. The claim that increased construction activity increased both the number of Mark and Locate requests and the number of dig-ins causing damage to PG&E's system does not change our view on the propriety of averaging. PG&E's witness acknowledged that Mark and Locate costs were and are recorded in operations Account 874, for which ORA does not recommend averaging.[26] Moreover no attempt was made to quantify the impact of dig-ins on test year maintenance expenses. There was no significant difference in the number of dig-in leaks between 1993 and 1996, and even though there was an increase in 1997, that does not demonstrate a trend. Logically, over time an increased number of Mark and Locate Requests would reduce (or at least partly offset increases in) costs associated with dig-ins.

Nor is PG&E's implementation of a new business / accounting system in 1996 sufficient reason for rejecting the use of averaging based on 1996 and earlier years. PG&E did not quantify the impact of its reclassification of A&G expenses to O&M accounts in its direct or rebuttal testimony.[27] Also, the removal of supervision and engineering costs from Account 885 and allocation of these costs to other maintenance accounts is not a reason for rejecting ORA's four-year average since ORA accounted for this change in developing its estimate. Finally, the fact that PG&E transferred some costs among gas O&M accounts is not a valid reason for rejecting a four-year average, since these transferred costs were not specifically identified. As a general matter, we do not find that PG&E's decision to implement a new system which involved the shifting of some costs among accounts should prevent parties from making recommendations based on long-standing and approved ratemaking techniques such as averaging. Given

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26 Even if ORA's 1993 to 1996 averaging approach were applied to this account, we note that the number of Mark and Locate requests increased 28% from 1992 to 1996. PG&E did not show what the change was from 1993 to 1996.

27 PG&E did submit an estimate of transferred A&G expenses in late-filed Exhibit 471. Although ORA requested the information on August 20, 1998, prior to the commencement of hearings, PG&E did not provide the information until after the close of hearings and even then was unable to provide the detail requested. The estimate was not subject to further discovery or cross-examination, and it would be unfair to give it weight in developing our adopted forecast of expenses.

PG&E's failure to show the dollar impact of such shifting in its attempt to rebut ORA's and Enron's averaging proposals, we give little weight to PG&E's arguments against averaging on the basis of accounting system changes.

We will therefore adopt ORA's four-year average approach for maintenance accounts. ORA's proposals for adjustments for IT programs are addressed in Section 9.6.

8.2.4.6 Adopted Gas Distribution O&M

Based on the foregoing, and our adopted treatment of savings for IT projects in Section 9.6, we adopt the following amounts for gas distribution O&M expenses. While the adopted amounts represent reductions from PG&E's request, the adopted gas maintenance amount is 20% higher than 1996 authorized and the total adopted O&M expense is increased by 4.8% over the amount adopted in the 1996 GRC.

Adopted Gas Distribution
O&M Expenses
(000's omitted, 1996 dollars)

Account	Description	Amount
	Operation	
870	Supervision and Engineering	0
871	Distribution Load Dispatching	603
874	Mains and Services	12,882
875	Measuring and Regulation Stations-General	758
876	Measuring and Regulation Stations-Industrial	454
878	Meter and House Regulator Expenses	2,294
879	Customer Installation Expenses	49,956
880	Other Expenses	19,035
881	Rents	0
	Total Operation	85,982
	Maintenance	
885	Supervision and Engineering	0
886	Structures and Improvements	1,115
887	Mains	17,055
889	Measuring and Regulation Stations-General	1,815
890	Measuring and Regulation Stations-Industrial	1,325
892	Services	11,036
893	Meters and House Regulators	5,793
894	Other Equipment	5,103
	Total Maintenance	43,242
	Total O&M	129,224

8.3 Capital

8.3.1 Production

PG&E does not propose any net plant additions for gas production. There are no disputed issues in this category of capital expenditure estimates. We adopt PG&E's estimate.

8.3.2 Storage

PG&E estimates $2.3 million in net plant additions for storage in 1998, and $2.4 million in 1999. Since rates for storage have been fixed by the Gas Accord through 2002, ORA did not take issue with PG&E's estimates. No other party takes issue with PG&E's gas storage capital expenditures estimate. We adopt PG&E's estimate.

8.3.3 Transmission

PG&E estimates $55.5 million in net plant additions for transmission in 1998, and $46.5 million in 1999. Since rates for transmission have been fixed by the Gas Accord through 2002, ORA did not take issue with PG&E's estimates.

TURN and Enron pointed out that under the Gas Accord, the cost of PG&E's Utility Electric Generation (UEG) gas meters should be included in gas transmission, and not in distribution. PG&E agrees that for ratemaking purposes the Gas Accord requires that the cost of the UEG gas meters be removed from the distribution revenue requirement. However, PG&E explains, this adjustment is not reflected in PG&E's recommended capital figures. Instead, an adjustment is made during the calculation of rates. Citing 18 Code of Federal Regulations, Part 201, PG&E believes that these costs should continue to be reflected in distribution plant Account 381 for accounting purposes. There is no transmission plant account for customer meters. PG&E states that through the BCAP process, customer access revenue requirements for transmission level end use customers, which include the costs of the UEG gas meters, are removed from the distribution revenue requirements to assure that distribution level customers do not pay for them. PG&E contends that the rates calculated in this GRC should be developed in the same manner.

All parties are in agreement that UEG meters should be included in transmission rates under the Gas Accord. In effect, PG&E reflects these costs in distribution for accounting purposes only. With this understanding, we adopt PG&E's estimate as reasonable. UEG meter costs shall not be included in distribution rates.

8.3.4 Distribution

8.3.4.1 Introduction

Gas distribution plant includes compressor station equipment, measuring and regulating equipment, mains, services, and regulators. Recorded and estimated gas plant also includes associated labor, material, supplies, contracts, and other items. PG&E states that it makes gas distribution capital expenditures to connect new customers, address safety and reliability issues, increase capacity to serve additional load, replace damaged facilities, and relocate and rearrange facilities to meet customer or regulatory needs. PG&E proposes three-year total net distribution plant additions for 1997-1999 of $677.6 million, based on $212.4 million in additions in 1997, $232.2 million in 1998, and $233 million in 1999.

ORA noted that PG&E's proposed plant additions expenditures were significantly higher than historical expenditures. ORA found that there is little correlation between total yearly plant additions and customer growth, and recommends that PG&E's recorded 1997 plant additions be used as the basis for 1998 and 1999 estimates. ORA proposes a three-year total of $648.5 million in net plant additions for distribution based on additions of $207.1 million in 1997, $217 million in 1998, and $224.5 million in 1999. The difference between ORA and PG&E is principally due to differences regarding the GPPR and Purchase Meters (MWC 25.)

TURN makes several recommendations with respect to GPRP plant, and recommends a capital spending reduction of nearly $18 million per year. TURN also proposes reducing PG&E's estimate for the new business MWC by $10 million, and reducing PG&E's rate base by $1.65 million to reflect new line extension rules.

Like ORA, Enron found that PG&E's proposed total distribution and replacement-related additions were excessive compared to historical levels. Enron also found customer growth to be slow and steady, and that load-growth related expenditures are very high relative to levels indicated in PG&E's resource plan. Enron proposes that a five-year average (1992-1996) be used to forecast gas distribution capital expenditures. Using this method, Enron proposes that capital additions of $567 million be approved for this GRC.

8.3.4.2 GPRP Plant

8.3.4.2.1 Forecast Expenditures

As noted earlier, the GPRP was established in 1985 to replace aging pipeline facilities. The GPRP, which is approximately halfway through its 25-year life, covers both transmission and distribution pipeline and is managed as a single program. Funding for the transmission component is now covered by the Gas Accord. Through 1996, 46% of 2,533 miles of eligible pipe and 85,919 services had been replaced. Through 1997, 47% of distribution pipeline mileage and 57% of transmission pipeline mileage had been replaced, or a total of 49% on a combined basis.

PG&E originally sought approval of distribution GPRP capital expenditures of $99 million per year in this GRC. In its March Update, PG&E estimated its distribution GPRP capital expenditures would be $78 million for both 1998 and 1999. PG&E developed its GPRP spending estimate by first estimating the miles of pipe to be replaced annually, based on the years remaining in the program and the miles of distribution pipe remaining to be replaced. Using this mileage estimate and historical per-mile costs for various localities, PG&E developed its annual GPRP capital spending cost estimate.

ORA recommends distribution GPRP funding of approximately $70 million per year based on its use of 1997 recorded spending. In support of its five-year average, Enron notes that in the past, PG&E has overcollected expenses and capital costs for the GPRP. In the 1996 GRC, Enron, notes, the Commission found (in D.95-12-055) that PG&E consistently underspent budgeted amounts in every year since the program's inception yet kept the program on schedule. Enron also faults PG&E's proposal for failing to show that PG&E has incorporated the beneficial effects of advanced technology. Enron finds this particularly troubling given PG&E’s touting of the benefits of its R&D programs.

Building on the same themes of underspending and technology, TURN notes that PG&E’s actual spending in 1998 was occurring at a slower pace than indicated by PG&E's plan to spend $78.0 million. After five months in 1998, PG&E had spent $22.4 million on GPRP activities, which projects to annual spending of $53.8 million. As of September 22, 1998, PG&E had spent $41.4 million, which projects to annual spending of $58.4 million. Between the end of May and September 22, PG&E spent at an annual rate of $64.9 million, or 16.6% less than PG&E’s estimate. TURN believes that PG&E's estimate should be reduced by at least 16.6%, and that the most reasonable estimate is $60.3 million, which reflects actual spending through May and continuation of the higher rate after May for the remainder of the year. TURN faults PG&E for not incorporating any costs savings for new technology such as Cured-In-Place Pipe liners. TURN is also concerned with PG&E's practice of holding 10% of distribution capital spending at the corporate level for contingencies. Finally, TURN is concerned that PG&E may not have appropriately accounted for the separation of the ratemaking treatment of the distribution and transmission components of the GPRP.

PG&E asserts that it has used technological advances such as directional drilling and vacuum evacuation to lower the per-mile cost of replacing gas pipeline, and that lowered costs are already reflected in its forecast. PG&E also asserts that there is no reason to expect that new technology will further significantly lower costs in the near future. In particular, PG&E asserts that due to long lead times, construction time, service limitation, and economics, Cured-In-Place Pipe liners will not be a significant factor during this GRC cycle.

Discussion

Several facts influence our consideration of PG&E's request. Although PG&E's proposed capital spending of $78 million for the distribution component of the GPRP is 30% greater than the ten-year historical average of $60 million per year (in 1998 dollars) for the program, this is reasonable in view of the fact that PG&E needs to replace an additional 20% of the distribution mileage each year to complete the distribution component on time. Although the GPRP has been and remains on generally schedule, the distribution specific component does appear to be lagging.[28] The cost savings associated with technological advances, such as Cured-In-Place Pipe liners, have not been quantified with respect to the distribution pipe.

However, we note that PG&E has consistently spent less than authorized amounts on the program throughout its existence, and as recently as 1998 was on track to spend up to 25% less than the $78 million estimate it advances in this GRC. In the last GRC, the Commission noted that from 1990 to 1994, PG&E underspent adopted capital and expense funding levels by $56.8 million. (D.95-12-055, 63 CPUC2d 570, 605.) In the three years from 1993 to 1996, PG&E spent $56.2 million less than it received in rates for capital costs. (*Id.*, 606.) The Commission then noted that:

> "Notwithstanding PG&E's underspending of budgeted funds in this program every year since 1985, PG&E has kept the program on target: after 40% of the program's timeline has elapsed, PG&E has completed 39% of the program. Apparently, we have funded this program at levels that are higher than required to fulfill program goals." (*Id.*)

The persistence of this pattern of underspending combined with PG&E's ability to keep the program generally on schedule leads us to suspect that its forecast may be higher than appropriate. However, the relatively small difference between ORA's and PG&E's forecasts for the distribution component leads us to conclude that PG&E's forecast for 1999 is reasonable. PG&E's

[28] As shown in Table 6-2 of Exhibit 28, PG&E should replace distribution pipeline at an average rate of more than 86 miles per year in the final 12 years of the program. In the first 13 years, PG&E replaced distribution pipe at an average rate of 72 miles per year. In contrast, PG&E replaced transmission pipe at an annual rate of 24.1 miles in the first 13 years and needs to replace transmission pipe at an annual rate of 20.1 miles for the remainder of the program.

requested spending level of $78 million specifically for the distribution component of the GPRP only is adopted, subject to the audit of 1999 capital spending described elsewhere.

8.3.4.2.2 Adjustment for 1994 Accounting Change

TURN recommends that $1.314 million be removed from the 1997 opening distribution plant balance because of PG&E's 1994 change in accounting policy to capitalize certain GPRP costs. TURN estimates this is the amount improperly capitalized in 1994 and 1995 due to the accounting change, which amount it refers to as the "fruit of an unapproved accounting change between rates cases." (Exhibit 369, p. 9.)

PG&E takes the position that TURN's proposed adjustment makes no sense. PG&E notes that TURN acknowledges that PG&E was undercapitalizing GPRP expenditures in the period immediately prior to the previous GRC, i.e., during 1994 and 1995.

As TURN points out, if a utility is going to unilaterally make an accounting policy change, it is obliged to ensure that implementation of the policy does not result in capitalization of costs that were treated as expenses in the most recent GRC. Further, as described above, the Public Utilities Code contains provisions intended to minimize the confusion of both utility and this Commission in the implementation of accounting procedures that affect ratecases that come before us, by reducing the circumstances where accounting changes will be implementaed unilaterally. Ratepayers already were paying for these costs as expenses which were approved in the 1993 GRC. Removal of $1.314 million from the plant balance will stem overpayments by the amount of 1994-95 costs that were treated as capital investments even as they continued to be treated as expenses. We adopt TURN's adjustment as reasonable.

8.3.4.2.3 Adjustment for 1996-1997 Capitalization

PG&E witness Ridings agreed with TURN that during 1996 and 1997, after PG&E changed to the new business system, PG&E did not record any expenses associated with the GPRP. PG&E agrees that it is reasonable to infer that it incorrectly capitalized some GPRP expenses from May of 1996 through the end of 1997. The witness indicated that it was reasonable to estimate that $0.12 million of expenses per month might have been capitalized during that period. PG&E has no objection to reducing operating plant by $2.4 million, which covers the 20 months from May 1996 through December 1997.

TURN agrees with this proposed adjustment. Consistent with our previous determinations with respect to the GPRP accounting policy change, we adopt this adjustment.

8.3.4.3 Other Major Work Categories

8.3.4.3.1 Purchase Meters (MWC 25)

In addition to the GPRP, ORA disagrees with PG&E on estimates for the Purchase Meters MWC. PG&E's forecast is based on the current meter inventory level as well as a forecast of the meters required for new customer connects, the scheduled meter change program, and miscellaneous meter changes. As PG&E notes, ORA did not investigate specific aspects of expected expenditures in this MWC. We are persuaded that PG&E's approach to estimating capital spending needs for this MWC is more likely to yield a reasonable estimate of those needs.

8.3.4.3.2 New Business (MWC 29)

PG&E's 1999 gas distribution new business capital expenditure forecast is based on the 1998 budget amount, multiplied by a growth factor, and then reduced 10% to reflect anticipated reductions in unit costs. The resulting forecast is $68.35 million for 1998 and $68.35 million for 1999. This estimate reflects an adjustment for the effect of the new line extension rules, discussed below.

TURN notes that PG&E's 1998 Customer Connections Capital Budget for gas new business is $67 million. TURN uses this as the 1998 budget amount. Based on a 10% reduction in unit costs predicted by PG&E, TURN predicts spending of $60.34 million. TURN recommends using this in lieu of PG&E's primary cost of $70 million in its GRC filing. TURN notes that the budget figure shows productivity improvements while PG&E's GRC request does not, and is generally consistent with PG&E's sales forecast. This translates into $13.5 in reductions to gross additions ($3.1 million in 1998 and $10.4 million in 1999).

Although TURN's forecast reflects average productivity improvements that PG&E itself expects to realize over the long run, it does not accurately reflect specific customer growth patterns that may inhibit productivity gains, or 1999 levels of activity. We will not speculate on productivity on the basis of this record. TURN's adjustment is therefore rejected. As suggested in our earlier discussion of electric distribution capital, Section 8.3 and following, an audit of actual 1999 activity will give us a better factual basis on which to base future rates.

8.3.4.3.3 Line Extension

TURN noted that new line extension rules may have the effect of lowering the amount of new business activity included in ratebase. PG&E agrees, and does not take issue with TURN's estimate that PG&E's forecast of ratebase should be reduced by $1.65 million to reflect the changes in the rules. This reduction will be reflected in our adopted estimates of capital spending.

8.3.4.4 Adopted Gas Distribution Capital

Our disposition of GPRP issues and Purchase Meter issues largely resolves the differences between PG&E and ORA. The principal remaining issue is whether to adopt PG&E's forecast approach as a starting point, with adjustments to reflect our determinations regarding the GPRP, New Business, and Line Extension, or to adopt Enron's averaging approach and resulting calculation of PG&E's capital spending needs.

Enron points to the results of PG&E's gas distribution regression analysis in PG&E's gas resource plan, and to PG&E's GPRP capital expenditure estimates. PG&E contends that neither of these components of PG&E's forecast supports Enron's position. PG&E contends that its capital expenditures estimate, reflecting its engineering judgment, is better than one based solely on the average of historic distribution capital expenditures.

While we do not accept all of PG&E's criticisms of averaging for capital expenditure estimates, we are nevertheless concerned that for gas distribution, an average based on historical spending gives insufficient weight to current conditions that are reflected in PG&E's budgeting and planning process. Also, PG&E's gas distribution regression results, derived in connection with the gas resource plan, are not generally inconsistent with PG&E's forecast of gas distribution capital expenditures. PG&E's engineering-based forecast of capital spending is more reasonable as a starting point and should be adopted with the adjustments determined previously. Specifically, PG&E's proposed three-year total net distribution plant additions of $677.6 million for 1997-1999 should be adopted. PG&E's rate base forecast should be reduced by $1.65 million as proposed by TURN and agreed to by PG&E to reflect the changes in the line extension rules. In addition, the 1997 beginning plant balance should be adjusted to reflect (1) removal of $1.314 million associated with 1994-95 GPRP costs that were treated as capital investments even as they continued to be treated as expenses; and (2) removal of $2.4 million associated with capitalization of GPRP expenses from May of 1996 through the end of 1997.

8.4 Gas Resource Plan

PG&E presented a gas resource plan as the basis to calculate long run marginal costs used in BCAPs for cost allocation and rate design. In addition, PG&E addressed compliance issues raised by the Commission in D.95-12-053. PG&E also presented alternate gas resource plans based on different design / reliability criteria.

Enron has shown that PG&E did not comprehensively evaluate alternatives to planned infrastructure investments such as energy efficiency and electric supply, and did not attempt to assess the value-of-service relationship between core gas and electric customers even though such an assessment may have been warranted. We recognize this as a deficiency which should be remedied to the extent we rely upon such plans in the future. However, there are no concrete proposals for changing the plan offered by PG&E in this record, and this deficiency weakens but does not render the plan inadequate or unreasonable.

Enron proposes that we reject PG&E's use of a 29 degree Abnormal Peak Day (APD) planning criterion (one in 90-year recurrence) in favor of a 31 degree

APD (one in 40-year recurrence). Enron believes that with changes in natural gas ratemaking such as PBR, heightened scrutiny of investment in distribution facilities is needed. Enron believes that a value-of-service study by PG&E supports this relaxation, and notes that SDG&E and Southern California Gas Company have adopted or proposed a one in 35-year planning criterion for their core customers.

PG&E agrees that such a relaxation may be warranted, and notes that the issue may be addressed in the Gas Strategy Rulemaking (R.98-01-011). PG&E nevertheless recommends that its gas resource plan be adopted for cost allocation and rate design purposes to the extent it is still needed in light of the adoption of the Gas Accord. PG&E notes that in the future, the regulatory framework adopted in the Gas Accord may have an effect on gas resource planning.

ORA recommends retaining the current one in 90-year planning criterion. ORA is concerned that PG&E's customers would receive little or no reduction in rates with lowered reliability standards. ORA recognizes that reliability issues are being addressed in R.98-01-011. TURN also opposes Enron’s proposal to relax reliability standards on the basis of this GRC record.

We will not change the one in 90-year planning criterion at this time, on the basis of this GRC record. While it is a higher standard than that used or proposed by other utilities, we are not persuaded that relaxing it as proposed by Enron is cost-effective. It is not clear that lowered reliability will yield significant savings for ratepayers and that it is consistent with value-of-service analysis.

Enron contends that PG&E’s gas resource plan does not provide a rational basis for PG&E’s load growth capital expenditures. According to Enron, PG&E’s distribution capital investment should be more closely tied to the distribution estimate developed as a part of the gas resource plan. While the “disconnect” between the resource plan and the capital spending forecast is somewhat troubling, we are not satisfied that the regression approach used in the gas resource plan is an accurate forecast of the planned, reasonable distribution capital expenditures. Also, as PG&E notes, the distribution regression results do not provide a direct comparison. The regression relates to mains only, while planned gas distribution capital expenditures also include services and other appurtenances.

No party takes issue with PG&E's position with respect to the D.95-12-053 compliance matters. As recommended by PG&E, the current planning horizons for backbone transmission and storage (15 years), local transmission (15 years), and distribution (five years), should be retained. To accurately reflect what is likely to transpire on an APD day, a portion of non-core load should continue to be included in APD modeling. As directed by D.95-12-053, PG&E's gas resource plan uses "ORA's methodology" for reflecting currently planned capital investments in the resource plan.

Based on the foregoing, we adopt PG&E's gas resource plan for purposes of long run marginal cost development. We note that ORA and PG&E believe that gas resource plans may not be needed in the future. In view of the current and possible future developments in the gas industry, it may become appropriate to waive the requirement for a gas resource plan, at least in connection with GRCs (to the extent that any GRCs are prosecuted in the future). We are not yet convinced that is the case. As Enron points out, sound resource planning may take on added importance. It seems clear that this issue will be further considered in other forums, perhaps including R.98-01-011, PG&E's PBR proceeding, and others. We will not remove or suspend the requirement at this time.

9. Common and Miscellaneous Revenues, Expenses, and Capital

9.1 Revenues

ORA and Weil raised issues related to Other Operating Revenues in their prepared testimony. ORA witness Thompson later submitted additional testimony that resolved all outstanding issues between PG&E and ORA regarding Other Operating Revenues. Thompson agreed that revenue adjustments associated with unbilled streetlights and other unmetered facilities, Rule 17 adjustments, and adjustments for revenues collected through PG&E's revenue assurance program should be reflected in Operating Revenues and not in Other Operating Revenues.

Weil raised a concern that Other Operating Revenues did not properly reflect the revenues PG&E receives from a contract with Bay Area Rapid Transit (BART) that went into effect on September 1, 1997. Weil later testified that he was satisfied with the explanation of PG&E's witness during hearings. An adjustment for the BART contract is not necessary.

Based on the foregoing, we adopt the estimates of Other Operating Revenue set forth in the comparison exhibit.

9.2 Expenses

9.2.1 Total Compensation

PG&E's application included a total compensation study conducted by Towers Perrin, an independent consultant. ORA, Towers Perrin and PG&E collaborated throughout the study. The study found that PG&E pays 7.23% more in total employee compensation than the average of firms surveyed. PG&E contends that this demonstrates that its compensation practices are reasonable and should be reflected in the revenue requirement authorized in this GRC.

ORA accepts the study result but contends it demonstrates that PG&E's total compensation is above market levels. ORA therefore recommends expense disallowances. Specifically, ORA recommends a downward adjustment in authorized total compensation of 6.7 %, from 107.23% to 100% of the survey average. As shown in the comparison exhibit, this results in adjustments of $18.1 million in electric expenses and $12.1 million in gas expenses.

FEA's primary recommendation for total compensation is similar to ORA's, although it recommends larger adjustments (in 1996 dollars) of $34.9 million and $18.4 million for electric and gas expenses respectively, and an additional adjustment of $18.4 million for employee benefits. As a secondary recommendation, FEA proposes that the total compensation be adjusted from 107.23% to 105% of the average as the Commission has done in prior rate cases. The corresponding adjustments for this secondary recommendation by FEA are $10.8 million for electric expenses, $5.7 million for gas expenses, and $5.7 million for employee benefits.

IBEW joins PG&E in opposing any disallowance, arguing that the Commission should accept as reasonable the compensation established through the collective bargaining process for PG&E's union-represented employees. IBEW contends that the Commission should reject the principle of market parity as the only basis for determining the reasonableness of compensation levels.

Discussion

In PG&E's last GRC, the Commission found that PG&E was not in the best position to independently analyze how its compensation compares to that offered by comparable firms because it has an incentive to underestimate its compensation relative to the market. (D.95-12-055, 63 CPUC2d 570, 590.) The Commission provided that in the event of another GRC, PG&E would be required to present a study in which independent experts have undertaken all analysis with regard to benchmarks, job matching, and the selection of comparable firms. (*Id.*) PG&E has done so.

Working in collaboration with ORA, PG&E agreed on key study design elements, including the selection of competitive labor market companies, the selection of benchmark jobs, and the aging factor to escalate survey data to a common point in time. ORA witness Lyons concluded that the study was valid, reliable, and complied with prior decisions. There is no dispute between PG&E and ORA over the study methodology or the result. We are satisfied that the total compensation study presented by PG&E conforms to professional practices for analysis of total compensation. The total compensation study substantially complies with the Commission's 1996 GRC decision regarding the use of independent experts.

PG&E points to four reasons why it believes the study overstates the extent to which its total compensation exceeds the surveyed group. These are California's higher labor costs, the degree of unionization, company size, and employee experience and turnover. The record evidence shows that PG&E's compensation practices result in its paying its employees 7.23% more on a weighted average basis than the compensation calculated for comparable firms. We find merit in PG&E's and IBEW's arguments that support a differential of this level.

We turn to the application of the study results in this GRC.   While we reject for now the contention that we should not apply labor market parity principle in evaluating the reasonableness of PG&E's compensation policies and practices, we intend to give utilities broad latitude in applying that principle. For ratemaking purposes, we should not allow cost recovery for more compensation than is necessary for PG&E to attract, retain, and motivate a workforce that allows it to provide adequate service, i.e., the market level.

The remaining question is whether PG&E's weighted total compensation package is at the market level. The answer rests with the definition of market level, and in particular the degree of confidence that can be ascribed to the mean value and any particular range of values which includes the mean.

It is clear from the evidence in this record that a range of error around the survey average is to be expected even with a faultless survey methodology. Accordingly, we reject the underlying premise of ORA's position and FEA's primary position, which is that any value higher than the survey average is above the market level and should be rejected as unreasonably high for ratemaking purposes. It is necessary to make an informed judgment about the maximum departure from the mean that still qualifies as the market level.

PG&E contends that for studies such as the one at issue here, any value which falls within a range defined by the mean compensation plus or minus 10% of the mean is at market and should be accepted as reasonable. In support of this position, PG&E has presented extensive and persuasive evidence that a 10% range is widely accepted among experts in the compensation field, particularly for a survey like the Towers Perrin study. PG&E witness Finkbeiner analyzed the five most heavily populated positions in the total compensation study. He found that at one standard deviation, the average dispersion from the survey average was about 12%. IBEW suggests that a range of plus or minus 15% may be appropriate, although IBEW witness Leonard appears to rely in part on studies of the fast food industry from 12 and 24 years ago in arriving at this conclusion.

Although the Commission has adopted a 5% range for compensation studies in past GRCs based on the records of those proceedings, PG&E and IBEW have demonstrated that a wider range is clearly appropriate in this case. While we concur with ORA and FEA that we should not allow above-market employee compensation to be reflected in utility revenue requirement, the record does not support the conclusion that PG&E pays its employees more than the market level of compensation on a combined, weighted average basis. In the absence of such a conclusion, ORA's and FEA's proposed adjustments are without merit and will not be adopted.

PG&E asserts that attracting and retaining employees has become more difficult in an increasingly competitive utility labor market due to restructuring. PG&E contends this puts upward pressure on the compensation it must pay in 1999. We find the evidence in support of this proposition to be at best incomplete, and give it little weight. Even though PG&E demonstrated that it has had problems recruiting experienced linemen, and there may be a competitive market emerging for meter technicians, there is countervailing evidence that must be considered. As ORA witness Lyons explained, restructuring could have two possible effects on compensation. Increased competition for workers may occur as PG&E contends, but increased competitive pressures could also lead to increased effort by employers to control costs. We agree with ORA that on the basis of this record, it is difficult to predict with any reasonable degree of reliability the effect that restructuring will have on compensation in the utility industry.

9.2.2 Administrative and General (A&G) Expenses

9.2.2.1 Introduction and Preliminary Matters

A&G expenses are of a general nature and are not directly chargeable to any specific utility function. They include general office labor and supply expenses and items such as insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses. In this case they make up between 20% and 25% of the revenue requested. The following table, abstracted from the comparison exhibit (p. A-67), shows PG&E's and ORA's final positions on A&G expenses.

PG&E's and ORA's Positions on
Total Company A&G Expenses
(1996 Dollars in Thousands)

Account	Description	PG&E	ORA	Difference
920	Salaries	$113,021	$91,279	$21,742
921	Office Supplies and Expenses	49,316	39,625	9,691
922	Transfer to Construction – Credit	(11,655)	(17,772)	6,117
923	Outside Services Expenses	71,878	45,834	26,044
924	Property Insurance	9,884	10,034	(150)
925	Injuries and Damages	75,248	74,298	950
926	Employee Pensions and Benefits	166,642	103,226	63,416
928	Regulatory Commission Expenses	50	50	0
930.2	Miscellaneous General Expenses	77,448	69,558	7,890
931	Rents	0	0	0
935	Maintenance of General Plant	7,701	7,701	0
	TOTAL	$559,532	$423,833	$135,699

TURN, Enron, and FEA generally support ORA's analysis and recommendations for A&G expenses. Each of these parties proposes limited additional adjustments, discussed below in connection with individual accounts. Weil recommends an adjustment to Account 925 to remove breach of contract costs. CAL-SLA proposes a reporting requirement with respect to franchise fees (Account 927), but raises no other issue with respect to A&G expenses.

PG&E explains its A&G expense estimates as follows. For labor costs, it reconstructed the total expenses for departments charging to Account 920. For corporate services departments, it then developed a forecast of incremental needs for 1999 relative to their 1997 labor expenses based on a survey of departments. For non-corporate services departments, PG&E assumed that A&G labor costs did not change from 1997. The resulting estimates of labor costs were then allocated among several categories to determine the amount to be included in the A&G revenue requirement.

An Effort Study (PG&E actually advanced several versions during the course of this proceeding) was used to allocate corporate service department labor costs to (1) utility operations A&G, (2) O&M, (3) capital (construction), (4) Diablo Canyon, (5) Line 401, (6) affiliates, and (7) holding company. Effort Study results were also used for allocating office supply costs and outside services costs. For Accounts 924 through 935, the estimating methodologies are addressed in the account-specific sections below.

The following sections (Sections 9.2.2.2 through 9.2.2.13) discuss PG&E's estimated A&G expenditures for 1999 on an account-by-account basis. We first address general concerns of the parties concerning PG&E's A&G showing. PG&E acknowledges that consideration of A&G expenses was both more complex and more controversial in this GRC than in past cases. PG&E attributes this to several factors, including the evolution of PG&E's holding company structure.[29] This led PG&E to submit several updates and changes in the way A&G expenses are allocated among the utility, holding company, and affiliates. Other complicating factors include changes associated with PG&E's new business system and the relative challenge of unbundling A&G expenses, which, unlike O&M expenses, cannot use account descriptions provided by FERC.

As ORA observes in connection with Account 920, PG&E's forecast changed many times during the course of this case. PG&E's original forecast was modified in its March Update. Further modifications to PG&E's showing occurred with PG&E's July errata, PG&E's August rebuttal testimony, PG&E's Additional Errata, and finally in the comparison exhibit. ORA contends that PG&E's moving target estimates of A&G expenses in this proceeding has seriously compromised its ability to effectively analyze its request. FEA witness Smith finds PG&E's showing for A&G Accounts 920, 921, 922, and 923 to be fraught with errors, unreliable, and poorly supported. For our part in this proceeding, we wonder how PG&E management is tracking these costs for its own internal purposes. There should not be a large variance between accounting procedures for internal purposes and the presentation made to this commission for ratemaking purposes.

TURN likewise raises several general concerns and criticisms regarding PG&E's showing, and particularly its Effort Study. TURN criticizes the frequent changes by PG&E, and commends ORA consultant Overland Consulting for "the

[29] Pursuant to D.96-11-017 (69 CPUC2d 167), on January 1, 1997, PG&E became a subsidiary of its new parent holding company, PG&E Corporation. Pacific Gas Transmission (PGT) and Pacific Enterprises, previously owned by PG&E, became wholly-owned subsidiaries of PG&E Corporation. PG&E's "non-regulated" affiliates are PG&E Energy Services, PG&E U.S. Generating, PG&E Gas Transmission, and PG&E Energy Trading.

thorough and dogged review it performed, and for finding as much as it did" under the circumstances.[30] (TURN Opening Brief, p. 56.) TURN asserts that the surveys used in the Effort Study were biased by self-interest of PG&E managers. TURN contends that it should be presumed that PG&E managers were generally aware of the differences between divisions subject to regulated base revenues and those which recover costs from competitive markets, and would act in their own self-interest by assigning costs and activities to the utility wherever possible.

TURN also finds a series of "quality control" flaws in the Effort Study. First, TURN claims that the studies gave inadequate attention to allocation of administrative support time. As an example of a consequent problem, professional staff of the Office of the Vice President of Computer and Telecommunications Services devoted substantial time to non-utility activities, but all of the time and expense associated with support staff was allocated to the utility. PG&E corrected this problem in one of the iterations of its showing, but other similar problems remain in the political resources department. TURN notes that few dollars are associated with this study flaw, but finds it to be more evidence of inadequate quality control. Second, TURN finds that the Effort Study did not make appropriate assignments of unproductive time. Third, despite frequent updates to its Effort Study, PG&E failed to accurately reflect known changes such as head counts reflecting the divestiture of generation facilities and the affiliate employee increase associated with the acquisition by PG&E U.S. Generating of the New England Electric System. Correcting these

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[30] Overland interviewed 25 PG&E employees and submitted 450 discovery questions. PG&E acknowledges that the Overland review of its A&G expenses was more detailed than reviews conducted in previous GRCs.

errors increases the affiliates allocation factor used by PG&E from 21% to 22%.[31] Fourth, TURN finds discomforting the fact that PG&E repeatedly conceded errors in its Effort Study and reduced its request by millions of dollars when intervenors were able to uncover such errors. TURN submits that the Commission should not be impressed by PG&E's concessions, but instead should view them as indicative of the flawed nature of PG&E's Effort Study.

Discussion

Although PG&E acknowledges the evolutionary nature of its A&G showing, it fails to take full credit for the delays and burdens it has imposed on other parties by its actions regarding its A&G showing in this GRC. By changing its A&G proposals and associated support on several occasions, PG&E made it difficult for other parties to analyze the proposals and underlying support, conduct discovery, and develop their own proposals.

Largely because of the changing nature of PG&E's showing during the course of the proceeding, the ALJ found it necessary to permit "surrebuttal" and "sur-surrebuttal" testimony and to defer hearing on A&G issues until near the end of the scheduled evidentiary hearings.[32] This mitigated the disadvantage

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[31] We have already noted the past problems that PG&E had counting trees in proximity to its distribution system. The record shows that PG&E has also had problems providing the Commission with accurate employee head counts in this GRC. While the highly-touted tree inventory data base has clearly assisted PG&E with its tree counting efforts, we decline to speculate on whether it could be adapted to other purposes.

[32] It may be more accurate to characterize PG&E's so-called rebuttal A&G testimony as its initial direct showing. It is perhaps in the area of A&G expenses that PG&E strayed the farthest from the principle that it is unacceptable for utilities to "offer only the most minimal support for their rate requests, choosing instead to wait to see what subjects appear to be of interest to [ORA]," then, in response to ORA's concerns, provide focused rebuttal. (D.92-12-019, 46 CPUC2d 538, 764.) PG&E also managed to run afoul

Footnote continued on next page

faced by ORA and other parties that addressed A&G expenses. We also recognize that some of the changes made by PG&E had the effect of reducing its requested revenue requirements. However, we remain concerned that the provision for additional testimony did not fully overcome the problems posed by PG&E's "moving target" approach to its A&G showing. We must conclude that the ability of ORA and other intervenors to fairly address PG&E's A&G showing was compromised. PG&E's decisions to establish a holding company structure and to implement a new business system, and the adoption of new affiliate transaction rules in D.97-12-088, may indeed all have complicated the review of A&G expenses. Nevertheless, these developments do not justify placing parties who addressed PG&E's A&G request at a procedural disadvantage if it means a less informed record on which we are compelled to decide.

For this reason, it is appropriate to accord reduced weight to evidence advanced by PG&E in support of its A&G request as we evaluate PG&E's showing on an account-by-account basis. We will remain mindful of the utility's burden of proof as we consider the evidentiary detail.

9.2.2.2 Account 920 - Labor

9.2.2.2.1 Overview

In its rebuttal testimony, PG&E corrected several errors in its Account 920 forecast that were noted by ORA in its prepared testimony. Three remaining areas of disagreement between PG&E and ORA pertain to PG&E's proposed

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of the ground rules on rebuttal testimony set forth in Appendix B of the April 7, 1998 Scoping ACR. Arguably, the actions of PG&E in this case were even more egregious than the situation the Commission found unacceptable in D.92-12-019, since PG&E did not present its "minimally supported" direct A&G proposal until the time set for rebuttal.

incremental forecast adjustments, the costs of PG&E's Performance Incentive Plan (PIP), and the costs associated with severance pay. We first address these three areas, then turn to disputes over Account 920 allocations.

9.2.2.2.2 Incremental Forecast Adjustments

In its March Update, PG&E included $9.4 million in incremental forecast adjustments to Account 920 to increase 1999 test-year costs over 1997 recorded levels. PG&E reduced this adjustment to $6.9 million in its rebuttal workpapers. PG&E further reduced the increase in Account 920 to $5.7 million. ORA believes these incremental forecast adjustments should be rejected. PG&E made similar adjustments in other accounts, increasing Account 921 by $11.2 million and decreasing Account 922 (a contra account used to transfer Account 920 and Account 921 costs to construction) by $535,000. The net increase forecast by PG&E for Accounts 920, 921 and 922 resulting from the incremental adjustments was $16.3 million. Because PG&E used a similar approach to incremental adjustments for Accounts 921 and 922, they are addressed together here. ORA contends that PG&E's proposed incremental forecast adjustments to Accounts 920, 921 and 922 should be rejected both because they are inconsistent with known factors impacting PG&E's A&G costs and because they are not adequately supported.

ORA first contends that PG&E's policy of radically reducing costs, as reflected in a May 29, 1997 statement by PG&E's President and Chief Executive Officer, Gordon Smith, should result in 1999 constant dollar costs in Accounts 920 and 921 which are below the 1997 recorded level. ORA notes that PG&E was implementing two major cost reduction efforts in 1998, the Smart Spending Program and the Overhead Optimization Study. The Smart Spending program was expected to reduce PG&E's 1999 operating expenses by

$68.1 million, reduce its 1998 and 1999 capital expenditures by $90.4 million, and produce total 1998 and 1999 savings of $220 million. After full implementation, the Smart Spending Program was expected to yield annual savings of $157.5 million. The Overhead Optimization Study was thought to have potential savings of $140.0 million for 1999, before accounting for severance and other implementation costs. ORA notes that because the organizations included in the Overhead Optimization Study are largely corporate services organizations, the majority of the potential savings are expense rather than capital savings. Finally, ORA notes that PG&E was also establishing a ten-person organization reporting to PG&E's Chief Financial Officer to implement initiatives to improve cost performance.

ORA next observes that PG&E's total work force decreased from 23,709 employees in March 1997 to 22,442 employees in March 1998, and continued to fall thereafter. As of July 1998, PG&E had 20,535 employees, including 179 utility employees who worked at the Wave 1 power plants. The July 1998 employee headcount does not include utility employees that have transferred to PG&E Corporation. PG&E Corporation has approximately 240 to 250 employees, but not all of those employees were transferred to PG&E Corporation from PG&E. ORA contends that reductions in PG&E's headcount result in reductions in the staffing of several PG&E departments which charge costs to A&G expense, and that staffing reductions in departments which do not directly charge A&G expense ultimately result in reductions in PG&E's A&G expenses.

ORA contends that the evidence shows that PG&E was clearly moving forward with its plan to radically reduce costs, and that PG&E's proposed incremental adjustments to increase A&G costs are inconsistent with known management policies and actions. ORA disputes PG&E's rebuttal testimony that estimates of savings from the Smart Spending Program and the Overhead Optimization Program are either speculative or already reflected in PG&E's estimates of A&G and O&M expenses. ORA points to PG&E's admission that it cannot identify any specific A&G or O&M cost reductions resulting from the Smart Savings Program or Overhead Optimization Study which have been reflected in its GRC estimates. ORA further contends that the savings identified in these programs are no more speculative than PG&E's proposed incremental adjustments to increase A&G expenses, and are in fact better documented and more reliable because they were not prepared for use in a rate case. ORA believes that even if a fraction of the savings anticipated from the cost saving initiatives are realized, the savings will be sufficient to completely offset the cost increases identified by PG&E. Finally, ORA contends that PG&E has a history of ignoring its cost cutting efforts in ratemaking proceedings, as the Commission has recognized.[33]

ORA also contends that PG&E has failed to provide adequate support for its incremental adjustments. ORA notes that PG&E submitted its incremental cost adjustments with its March Update on March 23, 1998. Three days later, ORA requested all workpapers, calculations and data used to derive PG&E's incremental forecast adjustments. ORA notes that PG&E responded 39 days later

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[33] In adopting the incremental cost incentive price plan for Diablo Canyon, the Commission found that:

"PG&E estimates that Diablo Canyon O&M expenses will be $257.3 million in 1997. PG&E's method of forecasting and its ignoring of its own efforts to reduce costs as evidenced by its staffing estimates among others are so out of touch with reality that they can be given no weight. TURN's proposal to start with 1995 costs as the basic number for O&M spending is reasonable and will be adopted." (D.97-05-088, mimeo., p. 76.)

with what ORA found to be inadequate justification, consisting of one page forms prepared by PG&E's Corporate Services Departments that contained brief, cryptic descriptions of the reasons for the adjustment and no support for the amount of the adjustment. As an example, ORA refers to the form submitted by PG&E's VP-Regulatory Relations Department which forecasted a $455,000 increase in Accounts 920 and 921. The only description of the reason for the increase was that it was "due to a forecasted increase in discovery." The form contained no information concerning how the increase amount of $455,000 was calculated.

Additional problems with PG&E' showing in support of incremental A&G expense increases that were found by ORA include the following:

> PG&E witness Holton could not state how the information in Appendix A to his rebuttal testimony (PG&E's complete, detailed departmental level showing on incremental A&G increases) would allow an auditor to spot any errors in several of the incremental increase estimates or verify the calculations.[34]
>
> Appendix A provides information for just 43 of 88 Provider Cost Centers for which PG&E proposes incremental increases.
>
> Holton admitted that a forecast adjustment of $1.0 million for a new reengineering group in the Business Systems Integration Department (BSID) included no information on the number of employees included, the number of employees transferred, or calculations supporting an increase of $500,000 in Account 921.

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[34] PG&E makes the minor point that forecasts cannot be audited in the same way as recorded amounts. We understand ORA's reference to "auditor" to mean one who investigates and analyzes the validity and reliability of PG&E's forecast, not necessarily a licensed financial auditor. ORA's complaint regarding its inability to "audit" PG&E's showing clearly refers to the lack of support in terms of underlying assumptions and calculations for departmental estimates of incremental expenses.

Holton admitted that Appendix A does not provide any calculations supporting the $951,000 incremental forecast adjustment to Account 921 requested for the Payroll Department.

PG&E’s incremental forecast adjustment to Account 920 for the Corporate Accounting Department reflects the addition of seven analyst and senior analyst full time equivalent positions. Holton estimated the average pay for the new positions is in the “mid-70's” and was not able to explain why the incremental forecast adjustment to Account 920 equals $86,857 per position.

PG&E’s incremental forecast adjustment to Account 920 for the Corporate Accounting Department reflects an increase in risk management accounting staffing of 5.5 full time equivalent positions. Appendix A indicates “the salary range for the people brought into the risk management accounting group is 50- to 55,000.” The incremental forecast adjustment to Account 920 for the Corporate Accounting Department averages $92,727 per position. Holton admitted that Appendix A and PG&E’s workpapers do not contain the information needed to verify that PG&E’s requested incremental increase to Account 920 for the Corporate Accounting Department was calculated correctly.

PG&E’s incremental forecast adjustment to Account 920 for the Regulatory Relations Department includes an increase of approximately $240,000 to reflect the transfer of PG&E’s tariff group from the Rates Department to the Regulatory Relations Department. The transfer did not result in a net increase in PG&E personnel. Holton admitted PG&E did not make a corresponding adjustment to reduce the cost of the Rates Department.

Appendix A and PG&E’s workpapers do not contain the calculations used to derive PG&E’s proposed $364,000 incremental adjustment to increase Account 920 for the Revenue Requirements Department. The stated reason for the increase is “a forecasted increase in all aspects of rate case management to support PG&E’s participation in rate and restructuring cases before the Commission and the Federal Energy Regulatory Commission.” Holton admitted that 1997 was not a year of unusually low regulatory activity for PG&E, and that Appendix A does not include a comparison of 1997 regulatory activities to the regulatory activities PG&E expects to occur in 1999.

Holton made an incremental adjustment of $2.3 million to increase Account 920 for the Local Governmental Relations Department. The increase reflects the transfer of field area personnel to the Local Governmental Relations Department from the Community Relations Department. Holton failed to make a corresponding adjustment to reduce the costs of the Community Relations Department to reflect the transfer. Holton admitted that he had double counted the labor costs of the field area personnel in his forecasts for the Local Governmental Relations Department and the Community Relations Department. Holton also admitted that he failed to reduce the Community Relations Department's Account 921 costs to reflect the transfer.

Holton admitted that the reason stated in Appendix A for the $195,000 incremental increase to Account 920 for the News and Advertising Department does not justify the requested increase. Holton also admitted that Appendix A and PG&E's workpapers do not include the calculations showing the derivation of the $195,000 increase.

PG&E's incremental forecast adjustment for the Shareholder Services Department includes a $501,000 increase to Account 921 for "two additional shareholder communications per year." Holton did not know how many shareholder communications PG&E sent in 1997. Holton admitted Appendix A does not contain any support for the assumption that PG&E will send two additional communications to shareholders in 1999 other than a statement that in 1996, PG&E sent a letter to all shareholders announcing a dividend reduction, and that for 1998 and 1999 PG&E assumed that it would send two communications per year to shareholders.

Holton admitted that Appendix A and PG&E's workpapers do not contain the calculations supporting PG&E's proposed incremental increase to Account 920 for the Tax Department.

Holton admitted that he failed to make a $592,807 adjustment to reduce Account 921 to eliminate the costs of the Business System Replacement Project. Holton admitted that the Business System Replacement Project is "essentially over" and that the costs of the project should have been removed from his Account 921 forecast.

Discussion

ORA has cast substantial doubt on the reliability of PG&E's proposed incremental adjustments in Accounts 920, 921, and 922. PG&E's process was clearly error-prone, as indicated by the examples of PG&E's double counting of costs for the Local Governmental Relations and Community Relations Departments and its failure to remove non-recurring costs for the Business System Replacement Project. That PG&E's errors are understandable given the complexity of A&G forecasting is no justification for a significant increase in spending. The demonstrated errors lead us to doubt the reliability of other unsupported amounts included in the incremental forecast adjustments. Also, in several instances, PG&E failed to explain the reason for a departmental increase, or to explain how the proposed costs were calculated. As the Commission stated in SDG&E's 1993 GRC, questions regarding expected changes in staffing and operations, why specified adjustments are appropriate, and how they were calculated, should be easily answered by the utility's initial showing. (D.92-12-019, 46 CPUC2d 538, 764.)

We concur with ORA's assessment that PG&E's proposed incremental forecast adjustments to Accounts 920, 921 and 922 should be rejected both because they are inadequately supported and because they are inconsistent with known factors impacting PG&E's A&G costs.

It defies logic to ignore the impact of cost-cutting initiatives undertaken by PG&E, while assuming that for other reasons A&G costs will increase. Yet, as ORA has demonstrated, that is what PG&E has done. It is apparent that PG&E failed to conduct any meaningful analysis of the impact of the Smart Spending Program and the Overhead Optimization study on its GRC expense estimates. PG&E was not able to identify where specific reductions for these cost saving programs were reflected in its estimates. The argument that savings are speculative fails to address the question of why this commission should substantially increase corporate spending of ratepayer dollars. We concur with the assessment that given the importance of PG&E's cost cutting programs, ORA's recommendation is a conservative approach. ORA has not proposed reducing PG&E's A&G expenses by even a fraction of the $68.1 million in savings identified in the Smart Spending Program or the $140.0 million of potential savings identified in the Overhead Optimization Study. We merely reject PG&E's proposal to increase A&G expenses above 1997 levels.   We note that ORA agrees that its Account 921 recommendation should be increased by $2.8 million to reflect a BSID adjustment.

9.2.2.2.3 PIP Expenses

PG&E's PIP program provides a component of PG&E's compensation based on a performance measure. The performance score is a number between zero and two. Higher PIP scores result in higher payouts to employees. PIP goals are set so that over time, the expected result is a PIP score of one. However, PIP payouts fluctuate significantly from year to year. PG&E estimated its 1999 PIP costs to be $26.5 million in 1996 dollars by assuming a PIP score of one.

The contested issues are the estimated amounts of PIP expenses expected to be paid out in 1999 and whether as a matter of policy the Commission should require ratepayers and shareholders to share the expected PIP costs. There is also a concern that adopting a PIP adjustment in combination with a total compensation adjustment could lead to double counting of adjustments.

Based on the five-year average of payouts from 1992 to 1996, ORA proposed reducing PG&E's PIP costs to 72.5% of the PIP target. ORA also supports the policy of sharing, discussed below. PG&E faults ORA's averaging approach because it fails to reflect the expected payout based on a performance score of 1.0. PG&E notes that for the 10 years ending in 1997, the average PIP payout was 98.7% of the targeted amount. PG&E believes that this historic data suggests that over time the PIP score will be near one.

Enron proposes a sharing approach under which PG&E would be authorized to collect 50% of its targeted payout level in revenue requirements. Enron finds that this is consistent with Commission decisions in which the funding of various incentive programs was at issue. For example, in PG&E's 1996 GRC decision, the Commission found that only 50% of the costs of PG&E's Management Incentive Program should be allowed. (D.95-12-055, 63 CPUC2d 570, 592.) Citing D.86-12-095, 23 CPUC2d 149, 187, the Commission noted its earlier holding that a management incentive pay program provides no incentives to utility management if the utility receives the full amount in rates. (*Id.*; see also D.96-01-011, 64 CPUC2d 241, 368.) Enron raises an additional concern regarding the collection of PIP costs associated with divested generation plants. Enron recommends that PG&E be required to submit a compliance filing which demonstrates that PIP costs were properly removed.

TURN goes even further and recommends total disallowance of PIP costs. TURN argues the evidence shows that PG&E's view of good performance by its employees is at odds with ratepayer interests. TURN reasons that if the employees perform well enough to allow their departments to meet or exceed corporate expectations, then shareholders are doing well and can afford to pay the bonuses out of earnings. If employees do not perform well enough to warrant bonuses, including the costs of bonuses in the revenue requirement would allow shareholders to become unduly enriched from costs included in rates but not paid out to employees.

TURN contends that the electric rate freeze mechanism and PG&E's policy of continuing the rate freeze through 2001 provides an additional set of incentives to PG&E management that render the historic approach of allowing 50% recovery obsolete. TURN believes that if PG&E employees are rewarded for helping the company to meet such goals, those employees are working at cross purposes with ratepayer interests. If the Commission denies its request for total disallowance of PIP costs, TURN supports 10% / 90% cost sharing by ratepayers and shareholders, respectively.

Discussion

We find no compelling evidence for a change in our current practice of allowing 50% recovery of targeted incentives from ratepayers. As we have held, shareholders and ratepayers alike benefit from the good performance that incentive programs such as PIP seek to encourage. We continue to believe that equal sharing of costs is fair, and that it provides appropriate incentives to the utility to perform in ways that benefit ratepayers and shareholders alike. Moreover, since the actual payout is less than the target payout in any year when employees do not perform well enough to earn targeted payouts, there is an unacceptable risk of overcollection of costs in the test year if we allow the inclusion of 100% of the targeted payout in rates. Continuing our policy of allowing 50% of targeted payouts mitigates this concern.

Although PG&E paid out just 72.5% of its target payout during the five years ending with 1996, it paid out nearly 100% of targeted costs over a ten year period. This affirms PG&E's contention that it is reasonable to base estimated payouts on an expected PIP score of 1.0. Accordingly, while we adopt Enron's proposal for equal sharing of PIP expenses, we provide that PG&E is entitled to recover 50% of its estimated payout of $26.5 million, which reflects a PIP performance score of 1.0.

We find unpersuasive the argument that PG&E’s incentives under the electric rate freeze to maximize revenue requirements warrant adoption of TURN’s proposal for requiring shareholders to pay 90% or 100% of the PIP expenses. Even though the rate freeze mechanism has affected the incentives faced by PG&E's management, and it may have motivated PG&E’s requests in this GRC, it is not as clear that such incentives will persist once this case is decided. We continue to believe that over time, ratepayer and shareholder interests are not so dissimilar as TURN suggests.

PG&E contends that a PIP adjustment in combination with an adjustment based on the total compensation study has the effect of double counting disallowances. PG&E explains that this is because the total compensation study assumes a PIP payout at 100% of the target. Accordingly, PG&E contends that recovery in Account 920 needs to be adjusted upward by $7.3 million if ORA’s PIP adjustment is adopted. PG&E further asserts that adoption of Enron's proposed PIP recommendation would require an even larger adjustment to avoid double counting of disallowances. While we have not adopted a total compensation adjustment, we briefly comment on PG&E's argument. As Enron correctly points out, there is no double counting in requiring 50% shareholder funding of the targeted full cost of this incentive plan in consideration of the fact that it benefits shareholders as well as ratepayers.

Enron has requested that PG&E be required to submit a compliance filing to demonstrate that PIP expenses associated with divested generation assets have been removed. This uncontested request is reasonable and will be adopted.

9.2.2.2.4 Severance Pay

PG&E contends that employee severance costs are a reasonable cost of doing business and should be reflected in rates. Account 920 includes PG&E's severance costs, which PG&E estimates will be $8.997 million in 1999. This estimate reflects actual severance costs for 1997, when 106 employees participated in the severance program. PG&E notes that while the reduced labor cost associated with a reduced headcount is one of the key benefits of providing a severance package, there is an additional benefit of improved morale and loyalty for remaining employees.

ORA acknowledges that PG&E incurs severance costs, but nevertheless contends that these costs should not be included in the authorized revenue requirement because reductions in employee levels associated with severance pay were not reflected in PG&E's 1999 forecast of operating expenses. ORA argues that if 1999 severance costs are included in Account 920 without a corresponding adjustment to reduce forecasted 1999 labor costs, PG&E will over-recover its costs.

Discussion

ORA does not question PG&E's assertion that it will actually pay severance costs in 1999. The issue is whether there should be consistency between the levels and trends in the number of employees and amount of severance payments in any year. By basing its forecast of severance payouts on the 1997 expense, PG&E implicitly assumes that an average of 106 employees per year will participate in the severance program in 1998 and 1999. Accordingly, the severance program would result in an average of 212 fewer full time equivalent employees in 1999 than in 1997.

PG&E witness Holton takes the position that whether employment levels are rising or falling in any year, PG&E will still make severance payments to departing employees each year. In effect, PG&E seems to deny or at least downplay any linkage between employment levels and severance pay. On its face, this is inconsistent with the fact that employees are eligible for severance pay if their position has been eliminated and no other position has been offered to the employee.[35] Why would there be severance pay if positions have not been eliminated? The answer cannot be that severance pay is made long after the position has been eliminated. Severance pay is paid in a lump sum when the employee leaves PG&E; the employee does not receive additional payments in subsequent years. In any event, PG&E witness Holton testified that reducing payroll costs as a result of reducing the headcount is a key benefit of providing a severance package.

We find that there is a linkage between employee headcount and severance pay even if every single instance of a severance payout is not associated with the elimination of a position. PG&E's forecast of $8.997 million in severance payouts may be correct, but PG&E still has not demonstrated that it has made appropriate corresponding downward adjustments to its GRC request to reflect the reduced head count associated with the severance pay it seeks to recover. Indeed, PG&E witness Holton did not prepare or review any analysis of

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35 There is conflicting evidence on this point. As reported in Exhibit 460, p. 6, PG&E indicated in a data response to ORA that employees are only eligible for severance pay if their position has been eliminated and no other work has been offered or assigned. On cross-examination, PG&E witness Holton testified that employees are also eligible for severance if their position is moved 50 miles or if they are offered a position at a lesser grade. (Tr. V. 47, p. 6010.) We are left to conclude that severance pay for relocated and downgraded positions is not a major factor in our analysis.

PG&E's overall total forecasted 1999 headcount consistent with PG&E's GRC expense estimates to confirm that the force reductions associated with his severance cost forecast have been reflected. Nor did Holton know the total December 1999 headcount assumed in PG&E's rate case estimates. As ORA notes, PG&E's A&G cost allocation witness Tucker included headcount in one of the allocation factors used to allocate costs to affiliates, and he used the July 1998 actual headcount because PG&E did not have a headcount projection for 1999. Clearly, PG&E's lack of a headcount forecast should not be considered as a reason to resolve this issue in the company's favor.

PG&E contends that ORA's recommendation in effect requires that PG&E identify which employees will receive severance payments before it can include these costs in its forecasts. We fail to understand this argument. ORA simply finds that PG&E has not provided the information needed to forecast labor cost reductions that correspond to the forecasted severance payments. ORA's request for this information is not unreasonable, and PG&E's failure to provide it constitutes a failure to justify its requested severance costs in revenue requirements.

Under the circumstances, it is neither reasonable nor fair to include severance pay expenses incurred by PG&E in 1999 revenue requirements. PG&E's request to include $8.997 million for severance costs is therefore denied.

9.2.2.2.5 Account 920 Allocation Issues

9.2.2.2.5.1 Introduction

PG&E separates A&G expenses into the regulatory categories of Construction, Diablo Canyon Nuclear Plant, Pipeline Expansion Project (Line 401), Affiliate Transactions, and Utility Expense based on the Effort Study for all surveyed provider cost centers (PCCs). Except for Construction, which is discussed in connection with Account 922, the following sections (Sections 9.2.2.2.5.2 through 9.2.2.2.5.5) address issues raised by ORA and TURN pertaining to the allocation of Account 920 expenses to these regulatory categories. ORA used PG&E's Effort Study as the starting point for its analysis. We will in effect do likewise, and adopt PG&E's allocations except to the extent we provide otherwise in the following sections. Because the cost allocation issues related to Accounts 920 and 921 are similar, these sections also address the separation of Account 921 into regulatory categories.

9.2.2.2.5.2 Allocations to Diablo Canyon

In D.88-12-083, the Commission adopted a ratemaking settlement which provided that ratepayers would pay only for the power produced by Diablo Canyon, and that the operating costs of Diablo Canyon are to be paid by PG&E. In PG&E's 1990 GRC, in D.89-12-057, the Commission considered and rejected the use of an incremental cost approach to Diablo Canyon cost segregation. The cost of activities that jointly benefit Diablo Canyon and other utility operations are to be allocated fairly between Diablo Canyon and the other utility operations based on the value of the services rendered or the benefits received.

PG&E agrees that the use of incremental allocations to Diablo Canyon should be rejected in this GRC. However, ORA contends that in practice, PG&E used an incremental cost approach to segregating Diablo Canyon cost in many instances. ORA believes that this may be explained by the fact that PG&E did not provide written guidance concerning Diablo Canyon cost segregation standards to the participants in its Effort Study. ORA maintains that PG&E's allocations of expenses associated with the regulatory relations, rates, and law departments represent an inappropriate incremental approach to assigning costs to Diablo Canyon.

With respect to Regulatory Relations, ORA notes that Diablo Canyon costs are recovered through the TCBA mechanism for transition cost recovery, and that the PCCs reporting to PG&E's Vice President-Regulatory Relations are responsible for managing cost recovery through the TCBA. The transition charges for Diablo Canyon incorporate the incremental cost incentive price procedure adopted in D.97-05-088. That decision provides for a variety of ongoing regulatory matters associated with Diablo Canyon including a cost verification audit, property tax balancing account, sharing of tax benefits and profit sharing. In addition, Diablo Canyon costs must be analyzed and removed from PG&E's overall cost structure in PG&E's GRCs. ORA finds PG&E's allocation of $34,703 of Regulatory Relations Department costs to Diablo Canyon to be grossly inadequate given the Diablo Canyon matters addressed by the Regulatory Relations Department.

ORA next points to PG&E's Rates Department. PG&E did not allocate any of the costs of its Rates Department to Diablo Canyon, yet it is responsible for preparing and presenting electric and gas rate proposals to the Commission, maintaining and enhancing customer data bases, and responding to customer requests for information. ORA contends that rate recovery is an essential function for the operation of Diablo Canyon. Diablo Canyon costs are incorporated into PG&E's overall rate structure through the CTC and recovered through rates administered by PG&E's Rates Department. ORA concludes that many of the activities of PG&E's Rates Department jointly benefit Diablo Canyon and PG&E's non-Diablo Canyon operations.

Finally, ORA faults PG&E's allocation of the time of 4.25 full time equivalent employees in its Law Department to Diablo Canyon. Because approximately 50% of the Law Department's employees are support personnel, PG&E's allocation in effect assigns the time of approximately two full time equivalent attorneys to Diablo Canyon. ORA notes that Diablo Canyon is subject to stringent Nuclear Regulatory Commission (NRC) regulatory requirements and the ratemaking jurisdiction of the Commission. Diablo Canyon has approximately 1,800 employees, annual production expenses of $313 million, and a decommissioning trust fund of approximately $1.0 billion. PG&E allocated $1.1 million in outside legal services to Diablo Canyon. ORA contends that given the significant legal requirements applicable to Diablo Canyon, two in-house attorneys and $1.1 million in annual outside legal costs is arguably inadequate to cover even incremental legal costs arising from ownership of Diablo Canyon.

Rejecting PG&E's approach to Diablo Canyon allocations, ORA recommends increasing the amount of labor expenses allocated to Diablo Canyon for seven departments: BSID, corporate accounting, tax, regulatory relations, rates, government relations, and law. ORA proposes allocations based on a general allocator derived from the percentage of PG&E employees who work in PG&E's nuclear generation business unit, excluding the Humboldt nuclear power plant. ORA contends that this headcount allocator is conservative because Diablo Canyon represents 8.1% of PG&E's employees excluding corporate services employees, but 13.5% of O&M payroll. Diablo Canyon produces more than 8.1% of PG&E's total revenues and represents more than 8.1% of PG&E's assets. PG&E criticizes this general approach as inferior to its own approach based on department-specific information obtained through the Effort Study.

TURN proposes a salary weighting adjustment for Account 920 allocations to Diablo Canyon to recognize the higher compensation of Diablo Canyon employees. The Commission adopted such an adjustment in the previous GRC, adjusting the allocation factor from 10.76% to 11.14%, or by 3.53%. TURN proposes a similar adjustment of 3.53% here. PG&E faults TURN's proposal as having no basis in the record. PG&E also believes that adding a salary weighting component to the effort study process would add to the study's already considerable complexity with little gain.

Discussion

To the extent we may rely on the Effort Study, we are generally more inclined to use its department-specific information instead of ORA's more general approach. As PG&E notes, the purpose of an Effort Study is to avoid the need for a generalized approach. Compared to credible department-specific data, a headcount allocator cannot account as well for the benefits received by Diablo Canyon from the activities of the various departments. Thus, whether to adopt ORA's or PG&E's recommended allocations to Diablo Canyon turns in large part on the reliability of PG&E's Effort Study.

Despite our general preference for using Effort Study results, we are not prepared to fully accept these results for all Diablo Canyon allocations. We have already noted some general problems with the Effort Study, and ORA has raised substantial doubts about the reliability of several of PG&E's allocations to Diablo Canyon based on the study. We are not convinced that PG&E took sufficient steps to ensure that departments reporting in the Effort Study were given instructions to report accurately, and we are particularly concerned that, despite PG&E's stated agreement with the principle that incremental allocations are inappropriate, its recommendations reflect such an approach in some cases.

In support of its position that it did not use an incremental approach to Diablo Canyon allocations, PG&E is able to point to the testimony of Witness Tucker that the allocations are "based on a study of the relationship between each department's costs and the value of services rendered on behalf of Diablo or the benefits received by Diablo from that department's activities." (Exhibit 424, pp. 3-8.) We have no doubt that was the intent, but we are not convinced that intent was carried out in all cases. We find that ORA's showing overcomes PG&E's position with respect to the vice-president-regulatory relations, rates, and law departments. Diablo Canyon clearly receives benefits from these departments that are greater than those reflected in the Effort Study. PG&E's allocations are insupportably low and are therefore rejected. We adopt instead ORA's allocations for Diablo Canyon with respect to the vice-president-regulatory relations, rates, and law departments. For the remaining departments (including BSID, corporate accounting, tax, and government relations), we adopt PG&E's allocations.

We also adopt TURN's proposed salary weighting. In the last GRC, the Commission noted with disfavor that PG&E's allocation method weights compensation so that an hour spent by an executive is valued the same as an hour of a junior clerical worker. (D.95-12-055, 63 CPUC2d 570, 597.) PG&E has not demonstrated why an allocation method that we rejected as inappropriate three years ago should be adopted now. PG&E points only to the lack of new data and the added complexity of salary weighting as reasons for rejecting it. We will not overturn our prior decision simply because PG&E provides inadequate information, especially when the need for that information should have been foreseen by PG&E based on the last GRC decision. Also, while TURN's recommendation reflects the use of data from the previous GRC, it is not correct to claim that it is not record-based. To the contrary, TURN's recommendation reflects the expert opinion of witness Marcus, offered in the record of this GRC, that the use of 1996 data is reasonable as a proxy value in the absence of more current information that PG&E should have provided. In addition, we fail to see how the complexity added by salary weighting justifies rejection of the approach we adopted in the last GRC. Accordingly, the Diablo Canyon A&G labor allocations are increased by 3.53% for Account 920 as proposed by TURN.

9.2.2.2.5.3 Allocations to Line 401

For departments participating in the Effort Study, PG&E allocated direct labor hours to Line 401 based on the study results and consistent with cost separation principles in D.94-02-042. ORA disputes the allocation for five departments, with a total impact of approximately $130,000. Notwithstanding our reservations regarding the Effort Study, ORA has not shown that the results are inappropriate for Line 401 allocations. We adopt PG&E's allocation proposal for Line 401.

9.2.2.2.5.4 Allocations to Affiliates and Holding Company

9.2.2.2.5.4.1 Introduction and Preliminary Matters

PG&E allocates labor hours to its affiliates and the holding company based on the Effort Study results. PG&E incorporates the 5% surcharge to affiliates required under the affiliate transaction rules by adding 5% to the hours directly attributable to affiliates and deducting the same number of hours from those attributable to the utility. We determine in our discussion of Account 930 that ORA's proposal to reflect the adder in that account should be adopted.

ORA disputes PG&E's allocations to affiliates for the BSID, corporate accounting, internal communications, governmental relations, political resources, law, shareholder services, and affiliate rules compliance departments. TURN also addresses allocation issues. Where ORA has shown significant problems with PG&E's departmental allocations, we will adopt ORA's recommendation. Otherwise, we rely upon PG&E's Effort Study. Below we address the areas of disagreement on a department-by-department basis.

9.2.2.2.5.4.2 BSID

ORA allocated 10% of BSID’s costs to affiliates. ORA notes the following: (1) BSID is responsible for integrating the SAP business system into PG&E’s management processes; (2) PG&E was the first affiliate to implement SAP; (3) PG&E incurred SAP implementation costs of $70.7 million; (4) the holding company and other affiliates have implemented or are in the process of implementing SAP; and (5) the holding company has established an Information Technology Council to share information technology among PG&E Corporation’s business lines and to capture economies of scale through joint purchasing. ORA contends that PG&E’s affiliates will benefit from its SAP development efforts, and that a portion of PG&E’s SAP development costs should therefore be charged to the affiliates. ORA considers its 10% allocation factor to be a proxy for the value of the information and other services provided to assist the affiliates in the implementation of SAP. ORA also states that its recommendation effectively allocates a portion of PG&E’s SAP development costs to affiliates.

PG&E criticizes ORA's allocation as not being based on any estimate of work expected to be performed by BSID for affiliates, and contends that its much lower estimate of .35% is based on the services BSID is expected to provide to affiliates in 1999. PG&E also notes that each of its affiliates has its own personnel responsible for SAP implementation.

We find PG&E's position on the BSID allocation to be better supported than ORA’s, and we therefore adopt PG&E's allocation. We understand the purpose of the Effort Study with respect to this allocation is to provide an estimate of the services that the BSID will perform on behalf of affiliates in the test year. This is a reasonable basis for making the A&G expense allocation. We question whether PG&E has fairly assigned SAP development costs to affiliates, but we are more concerned that ORA has not shown that its attempt to capture SAP development costs through its proposed allocation is justified.

9.2.2.2.5.4.3 Corporate Accounting

ORA based its allocation for the corporate accounting department on employee-by-employee reviews of department activities. PG&E agrees with ORA's estimate of the hours corporate accounting personnel will spend on affiliate matters. PG&E updated the department's headcount estimate, which resulted in a reduced allocation percentage, but ORA finds PG&E's explanation of the update to be incomplete.

We find that PG&E's headcount adjustment is not supported, and therefore adopt ORA's allocation for the corporate accounting department.

9.2.2.2.5.4.4 Internal Communications

In response to ORA's position on the allocation of expenses of the internal communications department, PG&E showed that the department does not provide audio-visual support to affiliates, PG&E Week is a utility product, and the intranet is utility-only, separated from the affiliates by a firewall. PG&E's allocation is reasonable and will be adopted.

9.2.2.2.5.4.5 Government Relations

PG&E's affiliates allocation for this department is reasonable and will be adopted.

9.2.2.2.5.4.6 Political Resources

PG&E contends that the work of the department is almost entirely utility-related, and that only a small portion (3.55%) of this department's labor should be allocated to affiliates. ORA disagrees, noting that PG&E Corporation seeks to present a consistent and unified message in contacts with elected officials and government agencies. ORA contends that the messages are inherently designed to benefit the holding company as a whole. ORA also points to evidence that a significant portion of the department's activities (at least two of five non-support positions) are for lobbying. ORA recommends that 40% of the costs of this department be charged to shareholder funded accounts as lobbying expense. ORA also recommends that 20.34% of the other three non-support positions, or 12.2%, be allocated to affiliates. In total, ORA recommends excluding 52.2% of the costs of this department from recovery in this GRC.

ORA's "consistent and unified message" argument is not persuasive. We accept PG&E's 3.55% affiliate allocation factor as reasonable. However, we also agree with ORA that it is not appropriate to include costs associated with lobbying. We therefore adopt ORA's proposal to exclude 40% of the costs of this department from recovery in this GRC. PG&E's 3.55% allocation will be applied to the remaining 60% of the department's costs.

9.2.2.2.5.4.7 Shareholder Services

PG&E proposes to allocate shareholder services costs between the non-utility affiliates and PG&E on the basis of their relative equity amounts. As shown in its opening brief, PG&E allocates 28% of shareholder services expenses to affiliates.

ORA proposes to allocate 84% of shareholder services to affiliates. ORA's position is explained as follows. PG&E has created a holding company structure in which the holding company is the utility's only shareholder. The primary function of PG&E's shareholder services department is serving as the transfer agent for PG&E Corporation's common stock. It also serves as the transfer agent for PG&E's bonds and preferred stock. Approximately 84% of the investment accounts handled by the department are PG&E Corporation common stock accounts. The 84% allocation is thus based on the services the department provides to PG&E Corporation. ORA goes on to note that the formation of a holding company has two consequences for the utility. First, the utility's ability to directly access the common equity markets is eliminated. This reduces the utility's financial flexibility, and could potentially impair its ability to issue new securities on reasonable terms. Second, the need for the utility to maintain shareholder services and investor relations functions is reduced to those required for the utility's preferred stock and debt. ORA finds it fundamentally unfair to require the utility and its ratepayers to bear the adverse consequences created by having only one common shareholder while simultaneously depriving the utility and its ratepayers of the relatively small and offsetting benefit produced by having only one common shareholder.

ORA's argument that PG&E has only one shareholder ignores the financial benefits of equity financing which are secured for the utility by the holding company. However, as ORA properly notes, the benefits are diminished by the utility's lack of direct access to equity markets. PG&E's analysis ignores the fact that this could potentially impair the utility's ability to issue new securities on reasonable terms, as ORA's testimony indicates. Faced with flawed recommendations by PG&E and ORA, we find it is reasonable to adopt a middle ground as more reflective of the value of services provided by this department. As a matter of judgment, we will therefore adopt the midpoint between PG&E's recommendation of 28% and ORA's recommendation of an 84% allocation. Accordingly, we adopt an allocation factor of 56%, and find it is reasonable to use this for allocating shareholder expenses to the holding company.

9.2.2.2.5.4.8 Law

PG&E's law department consists of 72 attorneys and 74 support personnel, primarily paralegals and secretaries. PG&E transferred seven attorneys and two support personnel to PG&E Corporation in January 1998. PG&E allocates less than 1% of the law department expense to affiliates. ORA allocates more than 3% to affiliates, based on an analysis that starts with 1997 charges.

PG&E allocates 666 attorney-hours and 635 law department support-hours to affiliates. The attorney-hours are assigned to three attorneys, one of whom was PGT's general counsel in 1996 and 1997. His time accounts for 540 of the 666 hours. Thus, in effect, PG&E forecasts only 126 attorney-hours for services to affiliates other than PGT. ORA finds this forecast to be unsupported, inconsistent with 1997 results, and not credible.

PG&E faults ORA's use of the law department's 1997 charges to affiliates, claiming it ignores the 1998 transfer of lawyers to the holding company. According to PG&E, these transferred attorneys will be responsible for virtually all of the support to non-utility affiliates previously provided by the law department. However, ORA claims that it specifically accounted for the transfer of attorneys from PG&E's law department to the holding company. ORA notes that the law department charged approximately 11,000 hours to affiliates and corporate oversight orders in 1997, mostly attorney-hours. Approximately 5,000 of these hours, or less than one-half, were charged by the employees who were subsequently transferred to the holding company.

ORA attributes 4,453 law department attorney-hours to affiliates, which is roughly equivalent to two full time attorneys. This includes 1,872 attorney-hours for addressing affiliate transactions regulatory matters. ORA contends that ratepayers should not be charged for legal costs related to affiliate transactions rules compliance and affiliate transactions ratemaking issues.

ORA's analysis shows that the law department can reasonably be expected to provide more than 126 hours of attorney services to affiliates other than PGT even after accounting for the 1998 transfer of seven attorneys out of the department. We find ORA's analysis to be more credible and reliable than PG&E's, and consistent with our treatment of affiliate compliance expenses, discussed below. We therefore adopt ORA's recommended allocation of law department expenses.

9.2.2.2.5.4.9 Affiliate Rules Compliance

The primary purpose of the affiliate rules compliance department is to ensure that the Commission's affiliate rules are followed. PG&E contends that all of the costs of this department should be allocated to PG&E. Supported by TURN, ORA recommends that 100% of this cost be allocated to affiliates.

PG&E witness Tucker reasons as follows. With the increasing complexity of the electric industry and the trend toward deregulation, PG&E has necessarily diversified its activities. Diversification led PG&E to form a holding company structure to provide separation between the utility and its non-regulated businesses, which became the utility's affiliates. The existence of affiliates then led the need for affiliate transactions rules. The affiliate rules compliance department maintains the proper separation between PG&E's regulated and unregulated activities, which PG&E calls an unavoidable consequence of electric industry restructuring. Tucker concludes that ratepayers benefit from electric industry restructuring and related deregulation, and it is reasonable that they pay the costs of protecting them from risks that are inherent in the restructured environment.

Short of actually coming out and saying so, PG&E implies that the decisions of California's legislators and regulators to restructure the electric services industry required PG&E to pursue business strategies that involve non-regulated lines of business. Once we have accepted that proposition, PG&E would then have us conclude that because it was required by the State to diversify, its gas and electric ratepayers should pay the full costs of ensuring compliance with rules designed to protect them against the risks of diversification.

We think it is more reasonable to conclude that electric industry restructuring created opportunities as well as risks for utilities and other businesses. Instead of being the inevitable result of industry restructuring, PG&E's establishment of a holding company structure and its pursuit of non-regulated lines of business can be better seen as simply a management decision to take advantage of new business opportunities that benefit shareholders.

PG&E has not demonstrated that utility ratepayers benefit from the profits earned by affiliates, or that ratepayers are in any other way the primary beneficiaries of its decisions to diversify into non-regulated activities. PG&E's establishment of a holding company which oversees affiliates that engage in non-regulated activities was largely, if not entirely, the consequence of management decisions that benefit shareholders. As TURN states, if PG&E had no affiliates, it would have no need of an affiliate compliance department. Moreover, ratepayers would have no exposure to the risks of non-regulated activities to be protected against in the first instance. Accordingly, the costs of affiliate rules compliance properly belong with the utility's affiliates. We therefore adopt ORA's recommendation to allocate compliance costs to the affiliates.

PG&E witness Tucker makes the point that the affiliate transactions department oversees Affiliate Rule VII, dealing with non-tariffed products and services, and also provides services unrelated to affiliate issues, including business ethics training. TURN concedes that Rule VII applies to activities that could benefit ratepayers. However, as TURN correctly states, this is the exception that proves the rule. It does not justify adoption of PG&E's recommendation to charge 100% of the department's costs to ratepayers. In the absence of an allocation of Rule VII and any other non-affiliate costs of this department by PG&E, its request is unjustified.

9.2.2.2.5.5 Allocations of Holding Company Costs to PG&E

9.2.2.2.5.5.1 Introduction and Preliminary Matters

Because PG&E Corporation was not staffed in 1996, and PG&E's original GRC showing on A&G expense estimates was based on 1996 costs, PG&E first presented a forecast of charges to PG&E from PG&E Corporation in its March Update. This forecast was modified substantially in PG&E's August 1998 rebuttal testimony to reflect the transfer of several PG&E departments to PG&E Corporation.

Using the Effort Study, PG&E allocated holding company direct labor and office supply costs to the Effort Study standard categories. For labor, the Effort Study survey asked PG&E Corporation departments to identify hours solely benefiting PG&E and hours benefiting PG&E Corporation as a whole. The costs were then allocated between PG&E and its affiliates using department-specific, size-based allocators. For most departments, a multi-factor allocator that weighs assets, operating expenses, and employee headcount was used. Portions of the costs allocated to PG&E in this process were then allocated to Diablo Canyon, and the remainder was included in the A&G component of revenue requirement.

PG&E again makes the point that it adopted a holding company structure to better respond to competitive changes in the utility industry, pursue new opportunities in energy services businesses, and improve the financial separation of utility operations from other lines of business. PG&E maintains that these are tangible benefits to subsidiaries, including the utility. For example, PG&E contends that the holding company structure enables the Commission to maintain a separation between PG&E's California utility activities and other energy service activities undertaken by the PG&E corporate family.

ORA objects to these allocations in several respects. TURN raises certain allocation issues as well. ORA notes that PG&E has requested recovery of $19.5 million in charges from PG&E Corporation, whereas ORA recommends $10.9 million in recoverable charges. Approximately $1.0 million of the difference is due to incremental forecast adjustments discussed earlier (in Section 9.2.2.2). Most of the difference, close to $8 million, is due to allocation differences.

ORA agrees to include charges from PG&E Corporation in its 1999 forecast to the extent that PG&E Corporation is expected to provide an actual identifiable service to PG&E, and PG&E actually needs the service. ORA contends that its approach is consistent with the Commission's Affiliate Transactions Rules, which limit charges to utilities from affiliates to charges for goods and services. In a major difference with PG&E, ORA takes the position that general supervision of subsidiaries by the holding company benefits the holding company and does not constitute a service to the subsidiary. Accordingly, ORA did not allocate holding company general supervisory costs to PG&E.

PG&E and ORA agree that holding company labor costs are ultimately reflected in Account 923. We follow the organizational convention of PG&E's brief and address the issue here. Before addressing department-specific allocation issues, we address broad issues pertaining to holding company allocations in this section.

Discussion

As support for its proposed holding company allocations, PG&E points to the recent Pacific Enterprises / Enova Corporation merger decision, in which the Commission indicated its intent that all parent company costs be allocated among the affiliates, including the utility affiliates. (D.98-03-073, mimeo., Attachment B, p. 17.) However, we are not persuaded that the conditions adopted in a merger case subject to Section 854(b), where short- and long-term economic benefits of the merger both must be found to exist and must be equitably allocated between shareholders and ratepayers, are readily transferable to this ratemaking case. That decision involved a careful balancing of interests based on the facts of that case and the requirements of Section 854. It is not legal authority for similar treatment of PG&E’s holding company costs.

We have already noted that PG&E Corporation was formed to allow shareholders to participate in non-regulated business opportunities. PG&E has not demonstrated that ratepayers receive substantive benefits from the non-regulated activities of PG&E’s affiliates. While it is reasonable to allow in utility rates those holding company charges that reflect the provision of services that are clearly needed by the utility, (and that are provided efficiently, without duplication of effort), it is also reasonable to require that incremental costs resulting from the formation of PG&E Corporation that provide no demonstrable benefit to the utility be allocated to the utility’s affiliates. This approach is consistent with PG&E's own approach prior to the formation of PG&E Corporation, when PG&E was the holding company for PGT and PG&E Enterprises. PG&E did not charge its subsidiaries for the cost of general corporate oversight performed by PG&E. Our approach is also consistent with Commission policy adopted in D.86-01-026, which states:

> "We believe that holding company costs should not be allowed if they would not have been incurred in the absence of [the holding company] structure and will adopt this position as Commission policy. The Commission has taken the view that determining the corporate structure is a management decision, yet the Commission obviously must be concerned with the public policy concerns for fairness and reasonableness to both shareholders and ratepayers as a result of such management decisions." (*Re Pacific Bell* (1986) 20 CPUC2d 237, 264.)

We find other problems with PG&E's showing in support of its holding company allocations. PG&E was generally unable to adequately document how the Effort Study accounts for services that PG&E Corporation was purportedly expected to provide to affiliates in 1998 and 1999. To the extent that the holding company structure results in two layers of senior officers providing the same or similar functions formerly provided by utility officers alone, we are concerned that there is significant potential for duplication of effort that should not be reflected in utility rates. Except where PG&E is able to demonstrate a clear, tangible benefit of holding company supervision, particularly by senior officers, allocating the costs of such supervision to PG&E would be unfair to ratepayers. Accordingly, except to the extent we provide otherwise in Sections 9.2.2.2.5.5.2 through 9.2.2.2.5.5.8, we adopt ORA's proposed allocations of holding company costs.

TURN argues that the headcount estimates used to allocate holding company expenses should reflect the shifting or reductions in employees associated with the anticipated Wave 2 of generation asset divestitures. However, the Wave 2 divestiture has not been reflected in any of PG&E's forecasts in this GRC.

TURN also raises the concern that activities of the price risk management department may be improperly allocated to ratepayers under PG&E's proposed allocation. PG&E does not explicitly state any objection to the principle that the activities of this department should be assigned to shareholders. However, PG&E contends that since TURN did not raise the issue until filing its opening brief, it has not had an opportunity to respond. We note that TURN calls PG&E's proposed allocation a relatively small amount. Because the issue was raised late in the proceeding, we do not address it further here.

9.2.2.2.5.5.2 President and Chief Executive Officer (CEO)

As shown in the comparison exhibit, PG&E allocates 45.68% of the labor cost of this PCC to the utility. PG&E takes the position that PG&E Corporation's CEO represents the interests of the holding company and its subsidiaries, including PG&E, to government, businesses, and the community-at-large. PG&E witness Tucker asserts the CEO plays an integral oversight role in the business activities of subsidiaries, and that this vision and leadership provides a benefit to PG&E. PG&E therefore asserts that it should share in the costs of PG&E Corporation's CEO.

ORA rejects any allocation of the costs of PG&E Corporation's CEO to PG&E. ORA's takes the position that PG&E has its own corporate officers, including its own President & CEO. ORA contends that the costs incurred by PG&E Corporation's senior officers are incremental costs directly attributable to the formation of PG&E Corporation. ORA contends that as a result, PG&E will not require any services from PG&E Corporation's senior officers.

As the senior executive official of the corporate enterprise, the holding company CEO uniquely provides overall vision and leadership through active involvement in the operations of subsidiaries. Our general concern regarding duplication of senior management functions in the parent company and in the subsidiary is not manifested here. We are persuaded that this PCC represents a tangible benefit to subsidiaries including PG&E. PG&E's allocation of 45.68% of the costs of this PCC is therefore reasonable and will be adopted.

9.2.2.2.5.5.3 Senior Vice President-General Counsel

As shown in the comparison exhibit, PG&E allocates 72.72% of the labor cost of the holding company’s senior vice president and general counsel to the utility. ORA allocates 0%.

PG&E takes the position that it should bear a reasonable share of the costs of this department. PG&E witness Tucker indicates that it deals with corporate governance issues, including SEC compliance. The department oversees and coordinates the legal advice and compliance functions among all subsidiaries.

PG&E has not demonstrated that its own law department needs to purchase legal oversight services from PG&E Corporation, nor has it demonstrated how the oversight services benefit PG&E. The coordination function performed by the holding company's general counsel is clearly an incremental requirement created by the shareholder’s desire to participate in non-regulated businesses. It should not be charged to ratepayers. Accordingly, we accept and adopt ORA's recommendation as reasonable.

9.2.2.2.5.5.4 Law

As shown in the comparison exhibit, PG&E allocates 65.25% of the labor cost of this PCC to the utility. As it did with respect to the holding company’s general counsel, PG&E takes the position that the corporate law department deals with corporate governance issues, including SEC compliance. PG&E contends that it should bear a reasonable share of these costs.

ORA allocates 13.79% of holding company law department costs to PG&E. This reflects 3,744 hours that the department reported on its Effort Study survey response for activities solely benefiting PG&E. PG&E witness Tucker lists nine services PG&E Corporation's law department provides to subsidiaries, but the response to ORA's discovery request demonstrates that the 3,744 hours that ORA assigned to PG&E account for most of the services listed by Tucker. PG&E has not demonstrated that PG&E will require more than the 3,744 hours of services estimated by ORA. Accordingly, we accept and adopt ORA's recommendation as reasonable.

9.2.2.2.5.5.5 Senior Vice President-Chief Financial Officer (CFO)

As shown in the comparison exhibit, PG&E allocates 72.72% of the labor cost of this PCC to the utility. ORA allocates 0%.

PG&E Corporation's CFO represents the PG&E corporate family, including PG&E, to the financial community. This holding company department also provides oversight to holding company finance departments, which in turn provide benefits to PG&E. PG&E argues that the utility and its ratepayers should bear a reasonable share of these costs.

ORA observes that PG&E has its own CFO, and contends that PG&E has failed to demonstrate that it needs to purchase any service from the holding company's CFO. PG&E witness Tucker lists access to and representation before the financial community; strategic advice on acquisitions, mergers and divestitures; and expertise on debt finance and capital structure issues as the benefits provided by the holding company's CFO to PG&E. He does not demonstrate why PG&E's own CFO is incapable of performing those functions directly. In addition, PG&E has not demonstrated any link between the asserted benefits and the actual amount of the proposed allocation to. Accordingly, we reject PG&E's proposal to allocate any of this PCC's costs to PG&E.

9.2.2.2.5.5.6 Business Planning

As shown in the comparison exhibit, PG&E allocates 72.72% of the labor cost of PG&E Corporation's Business Planning Department to the utility. PG&E witness Tucker indicates that this PCC provides the following benefits to PG&E: provision of guidelines and requirements for financial forecast and business plan submittal, review of business plans and negotiation of annual performance targets, and communication of corporate focus.

ORA rejects any allocation of this PCC's costs to the utility. PG&E was not able to produce written work products prepared by the planning department on behalf of PG&E or otherwise demonstrate the value of this PCC to PG&E. We are persuaded by ORA's testimony that the claimed benefits flow to the holding company, not PG&E, and that they represent incremental costs resulting from the formation of the holding company. Accordingly, we adopt ORA's proposal for no allocation of this PCC's costs to PG&E.

9.2.2.2.5.5.7 Vice President-Administration and External Relations

As shown in the comparison exhibit, PG&E allocates 72.72% of the labor cost of the holding company's administration and external relations department to the utility. PG&E asserts that the benefits of this department include oversight of the preparation of mandatory utility corporate reports. ORA notes that PG&E has its own corporate officers and its own external relations function, and rejects any allocation of this PCC's costs to the utility.

The functions of this PCC consist of general corporate oversight activities that benefit the holding company. Overseeing the preparation of mandatory utility corporate reports appears to be utility-related, but PG&E neither shows why its own officers are incapable of providing such oversight nor provides information concerning the number of hours the holding company's administration and external relations department will work on that activity in 1999. Accordingly, we adopt ORA's 0% allocation.

9.2.2.2.5.5.8 Vice President & Corporate Secretary

As shown in the comparison exhibit, PG&E allocates 65.33% of the labor cost of the holding company's corporate secretary department to PG&E. PG&E asserts that the costs of this department include costs associated with the holding company's participation in equity markets, such as participation in the holding company's annual shareholder meeting. PG&E takes the position that since its equity funding comes from this activity, it should share in this cost.

ORA allocates 14.25% of this PCC's costs to the utility. ORA's allocation is based on the positions that PG&E has its own corporate officers to provide these services; that since PG&E is denied the flexibility of direct access to equity markets, it should not pay the costs incurred by the holding company for accessing equity markets; and that PG&E has inappropriately included the costs of generation divestiture services provided by the holding company's corporate secretary department.

As noted earlier in our discussion of shareholder services costs, ORA does not give due credit for the fact that in the holding company structure, the utility subsidiary derives the benefit of access to equity markets from the parent company. However, this does not justify adoption of PG&E's recommended allocation of this PCC's expenses. First, we also noted in our discussion of shareholder services that the benefits are offset by the reduction in financial flexibility on the part of the utility. Moreover, PG&E's proposed allocation reflects the inappropriate assignment of generation divestiture costs to this GRC.

The only divestiture activities that were scheduled for 1999 were the sale of four Wave 2 power plants. As ORA notes, PG&E did not reflect the cost savings resulting from the Wave 2 divestitures in its 1999 forecast. With this in mind, as well as our general concern regarding the potential duplication of the efforts of senior officers of the utility and the parent holding company, we find that ORA's 14.25% allocation is reasonable.

9.2.2.3 Account 921 - Materials and Office Supplies

9.2.2.3.1 Forecast Amount and Allocations

The differences between PG&E's and ORA's estimates for Account 921 reflect their different positions regarding incremental forecast adjustments and allocation issues. We addressed PG&E's proposed incremental forecast adjustments in Section 9.2.2.2.2. As also noted earlier in Section 9.2.2.2.5.1, the allocation issues for this account are similar to those pertaining to Account 920. Both PG&E and ORA use the same allocation percentages that they used for Account 920 to allocate corporate services office supply costs, except that Account 921 allocations have not been adjusted for the 5% surcharge applicable to labor performed by the utility in support of affiliate activities. Accordingly, the allocation percentages we adopted for Account 920 are hereby adopted for Account 921 allocations without adjustment for the 5% affiliate surcharge on labor.

9.2.2.3.2 Rent Adjustment

Under its new business system, PG&E no longer charges rent expenses to Account 931-Rents. PG&E instead charges A&G-related rents to Account 921 through a facilities charge. Nevertheless, in its March Update, for purposes of continuity with past GRCs and prior regulatory reporting, PG&E forecast total company rental expenses in Account 931 of nearly $3.3 million dollars. This consisted of a transfer of approximately $1.2 million from Account 921 to Account 931 and an allocation of approximately $2.1 million of the $3.1 million rent paid by PG&E Corporation for its new offices at One Market Street.

ORA consultant Overland took issue with both the amount and the accounting of PG&E's holding company rental allocation. Based on its recommended allocation factors for labor, ORA proposed that $565,000 in holding company rental be allocated to PG&E in place of PG&E's recommended $2.1 million allocation. ORA also took the position that charges from PG&E Corporation to PG&E, including rent charges, should be recorded in Account 923-Outside Services. ORA thus recommended that PG&E receive $1.225 million dollars for rent expenses in Account 931. ORA asserted that its proposal was conservative because it increases overall office space costs at a time when PG&E’s general office complex rents were expected to be lower in 1998 than in 1996.

In its rebuttal testimony, PG&E stated it had reconsidered its earlier approach and reduced its forecast rental expenses in Account 931 to zero. PG&E also accepted and incorporated in its own showing ORA’s proposal to record rents related to outside support in Account 923. PG&E further agrees with ORA that the allocation of holding company rental charges should reflect the adopted labor allocation to the utility.

ORA next attempted to determine the amount of rental expense that was included within PG&E's Account 921 forecast. PG&E witness Holton was not initially able to provide the information. Holton later testified that the rental expense for leased office space was between 8% and 9% of the total dollar amount that PG&E has forecast for Account 921. Based on this testimony, ORA estimates that PG&E is anticipating incurring rental expenses of approximately $4.2 million.

ORA contends that PG&E should account for its lease cost in Account 931 in accordance with the FERC Uniform System of Accounts and generally accepted accounting principles. ORA asserts that PG&E's approach makes the rental expenses extremely difficult to track, and takes the position that PG&E has proposed booking its leased office expenses to Account 921 as a ploy to hide its rental expenses. ORA contends these expenses are approximately three times what they should be. ORA recommends that we allow $1.225 million on a total company basis for rental expenses, resulting in an adjustment of $2,966,860 ($4,191,860 - $1,225,000). Since PG&E has included its leased office expenses in Account 921, ORA proposes that the adjustment be added to ORA's previously recommended disallowance.

Discussion

ORA has not demonstrated that PG&E's accounting treatment of rental expenses contravenes FERC accounting requirements or generally accepted accounting principles. We will not require PG&E to track rental expenses in Account 931. However, ORA has raised troubling questions about PG&E's treatment of rental costs. Once again, the frequent and belated changes in PG&E's A&G showing in this GRC have complicated analysis and efforts to determine the just and reasonable revenue requirement, in this case for rental expenses.

We are persuaded that an adjustment is appropriate. PG&E's initial effort to be helpful in this GRC through "continuity with past GRCs" included a showing that it expected to incur $3.2 million in A&G rental expense, including about $2 million in charges from the holding company. PG&E eventually acknowledged that its new approach, first described in its rebuttal testimony, includes rental expense of 8% to 9% of its total company Account 921 forecast of $49.3 million. This equates to $4.2 million based on the midpoint of the 8% to 9% estimate. PG&E has not justified an increase in its estimated rental expense from $3.2 million to $4.2 million, and ORA has raised significant questions regarding the reasonableness of the original $3.2 million estimate.

In its reply brief, PG&E points to the testimony of ORA / Overland witness Harpster in which Harpster failed to identify ORA's continuing disagreement with PG&E regarding rental expenses. (Tr. V. 48, p. 6304.) PG&E contends that by addressing this issue in its opening brief in the wake of this testimony, ORA has engaged in inappropriate surprise litigation tactics. Ordinarily, we would be inclined to agree. However, in light of the troubled history of PG&E's A&G showing described earlier, it would be unfair to deny ORA the opportunity to argue its position on brief.

ORA's proposed adjustment to PG&E's rental expense is reasonable and appropriate under the circumstances. As shown in Exhibit 85, the recorded 1997 rent expense was $1.225 million. PG&E and ORA agree that the authorized rent expense for the holding company's new offices should be reflected in Account 923. Account 921 should therefore include no more than $1.225 million in rent expense. The record shows that PG&E has included approximately

$4.2 million in rent expense in its Account 921 estimate. We therefore adopt a downward adjustment of $2.967 million to Account 921, as proposed by ORA.

9.2.2.4 Account 922 - Allocation to Construction

9.2.2.4.1 Introduction and Preliminary Matters

Account 922 is a credit account used to transfer Account 920 and 921 costs to construction. Under the Uniform System of Accounts (USOA), the portions of Accounts 920 and 921 allocable to construction remain in Accounts 920 and 921 and are offset by a credit in Account 922.

The National Association of Regulatory Utility Commissioners (NARUC) has published interpretations of FERC USOA instructions concerning, among other things, the capitalization of overhead construction costs. The interpretation on capitalization indicates that the use of percentage distributions based on assumed relationships between operating expenses and the costs of construction violates USOA instructions. The interpretation also indicates that an incremental approach is preferred to determine the amounts of A&G costs which should be capitalized. Under this method, only costs specifically incurred for construction are chargeable to construction. Thus, the question to be answered is whether the cost would be incurred if construction were not undertaken.

PG&E and ORA agree that an incremental approach should be used for allocations to construction, and they appear to agree that the criterion for determining incremental costs is the extent to which a department's activities would be reduced in the absence of ongoing construction activities. Despite this agreement, ORA proposes larger allocations to this account than PG&E.

PG&E contends that the allocation factors used by ORA are inconsistent with the accounting guidance provided by FERC and NARUC, and that ORA has in fact used an embedded cost approach for several departments. ORA responds that had it done so, it would have allocated costs of organizations such as PG&E's CEO, treasurer, corporate accounting, budget, and revenue requirements PCCs to capital.

PG&E Witness O'Flanagan also criticizes ORA for using allocation factors at a departmental level to estimate costs attributable to capital. ORA asserts that this criticism is not valid. ORA notes that ORA Witness Harpster has extensive experience in the review of utility efforts studies, has reviewed FERC's compliance audit reports concerning effort studies, and has discussed the requirements for effort studies with FERC's Office of Chief Accountant. While FERC disapproves of using one overall allocator such as labor to allocate the entire Account 920 balance to capital, it does not object to the use of allocation factors at a departmental level which are consistent with the nature of the activities of the department. ORA notes that all of the efforts studies reviewed by Harpster, including PG&E's effort studies, have used department level allocations based on allocation factors that are consistent with the nature of the activities of the department.

Discussion

PG&E has not demonstrated that ORA has inappropriately used department level allocators. On the other hand, we are concerned that ORA's use of a labor-based allocator of 26.7% for several PCCs does not square with governing accounting guidelines. Nevertheless, for some departments it may be more reliable than PG&E's claims of no incremental costs. In Sections 9.2.2.4.2 through 9.2.2.4.9 below we address department-specific allocation issues for this account. In particular, we evaluate competing claims regarding whether the departments' activities would be reduced in the absence of ongoing construction activities. To the extent not specifically addressed in these sections, we adopt PG&E's proposed allocations to construction.

9.2.2.4.2 BSID

PG&E's BSID is responsible for SAP operations, maintenance and enhancement, and improving and integrating business processes that are based on SAP. PG&E attributed 3.53% of the BSID to capital, while ORA allocates 24.1% of the department's non-affiliate related direct labor hours to construction. PG&E asserts that BSID does no work to directly support field production, and that the only incremental effect elimination of construction might have on the department is a reduction in record storage costs.

ORA has shown that the volume of accounting transactions processed by the 21 employees in BSID's Business Systems Operations section would be significantly lower in the absence of PG&E's ongoing construction program. Also, PG&E's workforce would be significantly smaller in the absence of a construction program, reducing the staffing requirements for the SAP help desk and training activities performed by the BSID Change Management Section. Major systems addressed by the BSID include PG&E's general ledger, capital accounting, accounts payable, materials management, and Non-Energy Billing System / Mainline Extension Systems. The transactions volumes processed by those systems are all significantly increased by construction activities. Accordingly, the staffing and non-labor cost requirements in BSID related to those systems would be significantly lower in the absence of PG&E's ongoing construction program.

PG&E's position that only record storage costs would be eliminated with the elimination of construction activity is not realistic in light of ORA's testimony described above. We therefore adopt ORA's allocation of BSID costs.

9.2.2.4.3 Technology Support Center

PG&E does not forecast any charges in Account 920 or Account 921 for the Information, Infrastructure, and Operations technology support center. PG&E therefore believes that no costs for this department should be allocated from either account to construction. ORA did include costs of this department in its Account 920 and Account 921 forecasts, but entirely offset the cost by an equal credit in Account 922. PG&E witness Tucker testified that there are no revenue requirement impacts of adopting PG&E’s or ORA’s position. ORA similarly notes that its approach yields the same end result as PG&E's. ORA agrees that if no costs for this PCC are included in Accounts 920 and 921, then Account 922 should not include any credit for the portion of the department's costs allocable to construction. Accordingly, we adopt PG&E’s position.

9.2.2.4.4 Data Information Technology Department

The Data Information Technology Center is the operations group at PG&E’s Fairfield data center. PG&E contends that the systems administered by this department do not support any capital projects, and that the current department structure does not justify any allocation of this department's costs to construction.

ORA allocates approximately 6.3% of the department’s costs based on the 1990 GRC Effort Study. ORA contends that PG&E’s ongoing construction program increases the volume of transactions processed by the computer systems located at the Fairfield data center. The capital accounting system tracks thousands of construction work orders, and the accounts payable system processes thousands of invoices for construction projects. PG&E’s work force would be smaller in the absence of its ongoing construction program, reducing the volume of transactions processed by other systems. ORA notes that a 1990 study of metered computer usage attributed 6.3% of the Fairfield data center to construction. PG&E has removed metering equipment used to measure the computer usage, and is no longer able to provide metered usage by department. Acknowledging that the information is dated, ORA nevertheless adopted the capital percentage from the 1990 study as the best available indicator.

ORA has not shown why the 1990 study produces more reliable information than the Effort Study presented by PG&E in this GRC. We adopt PG&E's proposal to allocate none of this department's costs to construction.

9.2.2.4.5 Information Assets and Risk Management Department

The information assets and risk management department has two members who are expected to spend a significant amount of time addressing security issues with respect to the installation of new software. PG&E allocates none of their costs to construction, as the activities are associated with security issues related to software which is itself not capitalized. ORA’s allocation of 18% of this department’s costs to construction is based on an early version of the Effort Study that PG&E submitted with the application, an interview with the employee who prepared the Effort Study response, and the recorded 1997 charges to construction. PG&E has not shown why we should favor the later version of the Effort Study over the information developed by ORA. We adopt ORA’s proposed allocation of this department’s costs to construction.

9.2.2.4.6 Industrial Relations

PG&E allocates approximately 20% of the industrial relations department to capital. ORA attributes 26.7% of the department expenses to capital. ORA analyzed the construction related activities of PG&E’s union employees and determined that the staffing in this department could be reduced by at least 26.7% in the absence of PG&E’s ongoing construction program. ORA’s recommended allocation is reasonable and will be adopted.

9.2.2.4.7 Human Resources

PG&E disputes ORA's claim that the level of this department's staffing is essentially proportional to PG&E headcount. PG&E performed an analysis of the effect that elimination of construction activities would have in the human resources area. PG&E found that staffing levels in these departments are not always proportional to company employee headcount. Nevertheless, we find ORA's analysis to be more credible and reliable, and we therefore adopt ORA's allocations for the human resources PCCs. Proportionality aside, PG&E's human resources activities would be significantly smaller in the absence of any ongoing construction activity. ORA capitalized 26.7% of the labor costs of 37 of the 39 employees in the benefits department based on a review of their responsibilities. We find this to be more reliable than PG&E's estimate of 8.96%. PG&E admits that approximately 26.7% of the employees in the human resources services department could be eliminated if PG&E did not have an ongoing construction program. Also, a 26.7% reduction in the staffing levels of the services department would inevitably result in a substantial reduction in the office supplies and expenses for the corresponding PCCs.

9.2.2.4.8 Law Department

PG&E does not allocate any of the law department's expenses to construction. ORA's recommended allocation is 9.4%. PG&E asserts that department worked on only one or two assignments in the last five years which have been designated as a charge to capital, and the department is not aware of any such projects for 1999.

ORA points out that PG&E's 1997 FERC Form 1 filing shows that PG&E charged $527 million in labor costs to construction and plant removal in 1997. ORA contends that it is not credible to assert that construction activities of that magnitude do not result in any legal matters addressed by PG&E's Law

Department. Legal matters arising from construction include right-of-way permitting, contract disputes with construction contractors, and third party damages claims. ORA also contends that PG&E's total employment levels would be lower in the absence of an ongoing construction program, which would result in reduced employment litigation.

We find that staffing levels in PG&E's law department would likely be reduced in the absence of an ongoing construction program. ORA's recommended capitalization percentage of 9.4% was taken from PG&E's own 1990 Effort Study. As ORA points out, this information is dated, but we find it to be more reliable than PG&E's estimate that no costs would be reduced or eliminated in the absence of ongoing construction activity. Accordingly, we adopt ORA's allocation recommendation for this department.

9.2.2.4.9 Safety, Health and Claims

For the safety, health and claims department, PG&E maintains that only the worker's compensation group would be affected by the elimination of capital projects. PG&E accepts the use of ORA's general allocator of 26.7% for this group. However, PG&E asserts that the third-party claims and safety engineering groups would not be affected by the absence of construction projects, and therefore does not allocate any of these group's costs to construction.

In the 1996 Effort Study, this department estimated that 10% of the miscellaneous and automotive claims are associated with capital projects and that 20% of the labor hours for safety training, facility audits, and investigations are in support of capital projects. ORA's allocation of part of the third-party claims and safety engineering groups' expenses to construction is based on the 1996 Effort Study. PG&E's contention that third-party claims and safety engineering would not be affected by elimination of all construction activity is not realistic and is belied by PG&E's previous Effort Study. We therefore adopt ORA's proposed allocation of 15.9% of this department's labor costs to construction.

9.2.2.5 Account 923 - Outside Services

9.2.2.5.1 Introduction

ORA notes that PG&E presented five different forecasts for Account 923 in this GRC: in its application, in the March Update, in an Errata to the March Update, in rebuttal testimony, and in sur-surrebuttal testimony. With these changes, the only remaining difference between PG&E and ORA involves PG&E's proposal for outside legal services. In the following sections we address this dispute, differences regarding the allocation of total outside services, and differences in constant dollar adjustments.

9.2.2.5.2 Outside Legal Expenses

PG&E's request for $36.4 million for outside legal services expenses consists of $35.5 million for the utility law department and $855,000 for the newly-formed Corporate Law Department. The total request is $11.2 million, or 45%, more than the $25.1 million PG&E indicates it spent on outside legal services in 1997. Outside legal services account for 60% of PG&E's total request for outside expenses. ORA opposes this request, claiming that PG&E has not justified an increase over the 1997 level of expenses.

PG&E states that its estimate of outside legal expenses is based on the Effort Study survey of the law department and follow-up interviews with several individuals. The interviews included lawyers in PG&E's law department, among them PG&E's lead litigation lawyer; a law department budget officer; and the manager of PG&E's insurance department, who works closely with the law department on insurance and environmental matters. PG&E notes that at the time of hearings, it could not forecast exactly which legal cases would be active in 1999. Still, PG&E believes that it could make a reasonable forecast of legal expenses based on trends in regulatory, environmental, and other business factors which directly impact PG&E's outside legal services costs. PG&E provided a breakdown of the requested increase which shows an anticipated increase of $3.9 million in outside legal services costs for environmental and toxic tort litigation, $2.3 million associated with electric industry restructuring, and $2.9 million associated with a variety of other litigation matters.

ORA contends that despite the sheer volume of material submitted by PG&E in support of its A&G showing, PG&E has not shown why outside legal costs will increase. ORA finds several problems with the support offered by PG&E for increased outside legal expenses.

First, ORA faults PG&E's reference to the seven volumes of workpapers that provide department-specific information for the 59 Corporate Services departments. ORA notes that the survey for the law department, which should presumably include support for outside legal services, included no current or projected contracts. The only survey documentation for outside legal services was a summary of total dollars by Effort Study categories. PG&E witness Tucker acknowledged that this summary was the only support for an increase in forecast period outside legal services expense in the seven volumes.

ORA next points to PG&E's reliance on other A&G workpapers as part of its asserted substantial support. ORA found that PG&E's workpaper support for law department A&G expense, including outside legal services, consisted of two brief statements. The first statement addressed law department charges to the holding company and affiliates in 1997 and the impact of the transfer of eight billers to the holding company. PG&E witness Tucker acknowledged that this statement did not provide a reason for the increase in law department outside services. The second statement addressed the law department's management of legal contract and outside services. ORA notes that it lacks any reference to outside legal services, a point acknowledged by PG&E in cross-examination.

Third, PG&E relies on what it called an exhaustive list detailing the incremental increase. PG&E prepared it in response to ORA's testimony contending that PG&E failed to support increased outside legal expenses. ORA contends that this list provides only generic descriptions for each of PG&E's four business units. For example, ORA states that after stripping away the redundant text, PG&E's support with respect to the Distribution Customer Services unit is reduced to: "Increase in legal services related to ongoing and anticipated litigation cases, franchise issues, industry restructuring, contracting related issues, general business issues and a decrease in legal services related to regulatory cases / issues." ORA notes that the list contains similarly sparse, generic descriptions for the other three business units.

Finally, PG&E relies upon interviews of law department personnel as support for outside legal services costs. In its sur-surrebuttal testimony, PG&E attempted to justify its incremental outside legal services in part by estimating that it would incur approximately $3.9 million of additional legal services for environmental and toxic tort litigation and other matters. PG&E witness Tucker later disclosed under cross-examination that this estimate was developed from interviews with those familiar with the cases. Tucker acknowledged, however, that he had no notes or other documentation for these interviews.

Discussion

PG&E has presented only general statements regarding the subject matter of expected litigation, a breakdown which shows that environmental and toxic tort litigation and electric industry restructuring account for slightly more than half of the requested increase in outside legal expenses. While PG&E states that employees who have knowledge of pending litigation and trends in the law that could affect litigation requirements participated in the development of its forecast, this does not constitute substantive justification for increasing outside litigation expenses by any significant amount, let alone by close to half-again more than the amount spent in 1997.

We recognize PG&E's concern that it could not predict which cases would be active in 1999, and that it could only anticipate the general nature and amount of litigation it would face in 1999. As PG&E stated in a data response:

> "Due to the nature of the activities charged to Account 923, PG&E cannot forecast exactly which legal cases will be active in 1999. The need for legal services results when a claim is filed against PG&E and PG&E cannot exactly predict when a claim will be filed, why it will be filed, or what amount it will be filed for." (Exhibit 423, p. A-60.)

However, this uncertainty hardly provides support for PG&E's request for a large increase in outside legal expenses. To the contrary, it underscores the difficulty of predicting future legal activity, and particularly the need to incur outside legal expenses. Given this difficulty, it is entirely reasonable to rely on the actual spending in a recent year or the average recorded spending of recent years as the starting point, and possibly the ending point, of a forecast. It is equally reasonable to require the proponent of using any deviation from this recorded value to clearly demonstrate why a different value is more reliable.

PG&E has neither demonstrated that the 1997 level of outside legal activity that ORA relies upon was unusually low, nor provided any facts and cogent analysis that demonstrate why 1999 would yield completely different circumstances requiring a dramatic increase in outside legal expenses. We are left with an error-prone Effort Study, which clearly gave scant attention to the subject of outside legal expenses, and reports of informal, undocumented, and belatedly disclosed interviews of law and insurance department employees.

PG&E's criticism of ORA for not performing an independent evaluation of anticipated outside legal costs is of little consequence, since the burden of proof to demonstrate the reasonableness of PG&E's request rests with PG&E, not ORA. Moreover, the criticism is misplaced. ORA clearly attempted to investigate PG&E's proposal, but was stymied by PG&E's unwillingness or inability to timely and fully respond to ORA's data requests.

PG&E has failed to justify its requested increase in outside legal expenses. We therefore adopt ORA's recommendation to use the 1997 level of $25.1 million. We also reject PG&E's request for incremental expenses for the holding company's law department, since the 1997 recorded values used by ORA include legal services functions transferred to the holding company in 1998.

9.2.2.5.3 Allocations

ORA and PG&E dispute Account 923 allocations to utility operations A&G activity, construction, O&M, Diablo Canyon, Line 401, affiliates, and the holding company. PG&E directly assigned outside services to these categories using the Effort Study, which asked corporate services departments to estimate their expected outside service costs and to explain how those costs should be attributed to the Effort Study categories. ORA assigns Account 923 costs to these categories based on the percentages of Account 920 costs that are allocated among these categories.

ORA contends that the basis for PG&E's direct assignments is undocumented and therefore unsupported. In the absence of explanations supporting direct assignments of outside services to categories, ORA argues that labor is a sound, logical basis for allocation because it best reflects the cost of key activities performed by the department. ORA appears to concede that a sound, documented effort study would provide a more reliable basis for allocating outside expenses than allocations based on labor allocations. Thus, it is only because of its concerns with PG&E's Effort Study that ORA rejects PG&E's recommendation and instead uses a second-best approach.

PG&E has shown that there is little reason to assume that a department's labor and outside services costs will be allocated to different activities in the same proportions. On balance, notwithstanding the problems with the Effort Study, including the lack of documentation cited by ORA, we are persuaded that PG&E's allocation approach for outside services is more reliable than ORA's and should be adopted.

9.2.2.5.4 Constant Dollar Adjustments

PG&E has de-escalated forecast period Account 923 amounts using a 1997 to 1996 de-escalation factor of .9721. ORA notes that forecast period outside services estimates based on adjusted 1997 base period expense are stated in 1999 dollars. ORA contends that these estimates should be de-escalated using a 1999-to-1996 de-escalation factor of .91498. ORA notes that PG&E did not address its constant dollar calculation for Account 923 in rebuttal or in its sur-surrebuttal testimony. ORA's proposed de-escalation factor is reasonable and should be adopted for this purpose.

9.2.2.6 Account 924 - Insurance

9.2.2.6.1 Amount

With one exception, PG&E and ORA agree on the forecast amount for this account. With the sale of the Wave 1 plants, PG&E's insurance premiums decreased. Nevertheless, as part of its overall recommendation for treatment of A&G costs associated with the Wave 1 divestiture (discussed in Section 10.3 of this decision), ORA proposes to impute $428,000 of insurance costs to this account as though the Wave 1 power plants had not been divested. ORA agrees that if we adopt PG&E's proposal to reallocate Wave 1 A&G costs in this case, its recommended forecasts for A&G accounts should be reduced.

ORA has not demonstrated that imputing directly assignable insurance costs is necessary. ORA's approach is therefore denied.

9.2.2.6.2 Allocation

The only disputed allocation issue associated with Account 924 is whether ORA's proposal to allocate $279,000 of this expense to Line 401 should be adopted. PG&E disagrees with the proposal, citing its testimony that the combination of a high deductible and a limited maximum payout limits insurer risk, and that its insurers are therefore willing to cover Line 401 assets at no additional cost. Although ORA questions this conclusion, calling it counterintuitive, we find PG&E's testimony persuasive. ORA's proposal for a Line 401 allocation of insurance costs is therefore rejected.

9.2.2.7 Account 925 - Injuries and Damages

9.2.2.7.1 Introduction and Preliminary Matters

Account 925 includes amounts charged for uninsured losses, the costs of liability insurance premiums, and the costs of claims and suits for injuries and property damages. The account also includes workers' compensation payments to employees, and related medical and rehabilitation costs. ORA, TURN, Weil, FEA, and Enron raised several issues associated with this account.

PG&E and ORA have presented numerous estimates for Account 925 over the course of this proceeding. Most of their changes resulted in a narrowing of their differences. However, the evolution of the parties' A&G showings did not stop with the comparison exhibit. As shown in that exhibit, PG&E's latest forecast for this account is $75.2 million, while ORA's estimate is $74.3 million. However, this amount does not reflect ORA's support, reflected in its opening brief, for Weil's proposal to remove certain breach of contract costs, as well as certain other late adjustments and corrections. In its reply brief, ORA states that its updated and corrected Account 925 recommendation is $62.3 million. PG&E stated in its reply brief that it does not oppose removing costs associated with the Rough and Ready fire and the costs of a sex discrimination suit. We address these and other remaining issues in the following sections (Sections 9.2.2.7.2 through 9.2.2.7.9).

We find that PG&E's latest estimate for Account 925, as set forth in the comparison exhibit, represents a reasonable and appropriate starting point for our analysis and forecast of this account. It reflects agreement with ORA on the use of five-year averages, which we find to be appropriate given the annual fluctuations associated with the underlying claims and settlement costs. We are not persuaded that FEA's adjustments based on a six-year average produce more reliable results.

In D.99-06-080, Ordering Paragraph 29, as modified by D.99-11-055, the Commission provided that:

> PG&E shall not use the expenses related to claims paid out during the storm as a basis for its pending general rate case for justification of any expense forecast. It is our intent that PG&E not recover these

costs from ratepayers in the account used for claims payment recovery, as authorized in the general rate case.

To give effect to the Commission's order in D.99-06-080 as modified by D.99-11-055, PG&E is directed to reflect, in the final advice letter filing based on the complete, tax run model, any adjustment necessary to ensure that the authorized revenue requirement excludes these storm-related expenses.

9.2.2.7.2 Additional Adjustments

In its opening brief, ORA proposed adjustments for alleged double counting of light-duty payroll costs, an asserted difference in 1996 costs, and a constant dollar adjustment. PG&E replies that these adjustments were not previously articulated, and are based on workpaper interpretations which it has not had an opportunity to address.

We have attempted throughout the A&G section of this decision to recognize and ameliorate the impact of PG&E's frequent changes in its showing on the ability of other parties to analyze that showing and offer alternatives to it. In the case of ORA's additional adjustments to Account 925, however, we are persuaded that it would be unfair to adopt these adjustments without giving PG&E an opportunity to respond. In each proceeding the record must eventually be closed and a decision rendered. Another round of testimony is not warranted. Accordingly, we do not accept ORA's additional adjustments.

9.2.2.7.3 Breach of Contract Costs

In recent years PG&E has incurred substantial costs to settle and satisfy judgments in breach of contract lawsuits. The annual average expense for the six years from 1992 through 1997 was nearly $11 million in 1996 constant dollars. We note that the 1992 cost of $494,963 appears to have been unusually low compared to the following years. The annual average for the five years from 1993 through 1997 was approximately $13.1 million. On the other hand, the 1994 expense of $42.7 million was unusually high, more than four times the next highest yearly amount.

Weil proposes to remove all recorded breach of contract costs that are reflected in the averaging calculations for Account 925. Weil recognizes that litigation costs associated with the defense of breach of contract lawsuits are inevitable, and does not contest these costs. However, when PG&E settles a breach of contract suit or receives an adverse judgment, Weil takes the position that the resulting costs should not be borne by ratepayers in the absence of a showing by PG&E that the costs are necessary and reasonable.

ORA supports Weil's proposal, and recommends a downward adjustment to reflect the removal of breach of contract expenses. ORA believes that some level of expense for such lawsuits is inevitable, but submits that PG&E's expenses are excessive. ORA also believes that if PG&E is able to pass breach of contract expenses on to ratepayers, it will have no incentive to manage contracts effectively. Alternatively, ORA recommends removal of the 1994 expense as an anomalous event.

PG&E contends that breach of contract suits are an inevitable part of managing a business in today's litigious society, and are a reasonable cost which should be recovered in the cost of service. PG&E also asserts that breach of contract suits involve economic issues largely related to disagreements in how contracts are to be interpreted and executed, and do not involve issues of fraud or moral turpitude where a case could be made that PG&E acted with malicious intent. PG&E cites case law that holds that a finding of breach of contract does not imply the finding of a willful or bad act (see *Applied Equipment Corp v. Litton Saudi Arabia*, (1994) 7 Cal.4th 503, 516), and that even an undeniable breach does not necessarily constitute a wrongful act and some breaches may be beneficial to society (see *Harris v. Atlantic Richfield*, (1993) 14 Cal.App.4th 70, 77). PG&E

maintains that this undermines Weil's assumption that a finding of breach of contract is equivalent to a finding of imprudence.

Discussion

PG&E should aggressively seek to protect its interests and those of its ratepayers. This includes taking actions to implement its contract rights even though there is a chance for disagreement that could lead to a civil action. Moreover, a reasonable course of action with respect to the management of a contract can lead to a breach of contract dispute, litigation, and an adverse judgment. In other words, some level of expense for breach of contract suits can be expected as a reasonable, ongoing cost of doing business.

Weil accepts ratepayer funding of the legal costs associated with such actions. However, when PG&E pursues the defense of a particular case but loses or decides to settle it, Weil sees this as conclusive evidence that PG&E’s actions leading to the breach of contract lawsuit were unreasonable. We are not prepared to make that assumption. A breach of contract dispute may simply involve competing reasonable positions of the parties to a contract dispute. An adverse judgment does not, alone, demonstrate that PG&E acted unreasonably in the execution and administration of the disputed contract.

ORA argues that successful breach of contract suits against PG&E result from either mistakes or contracts that never should have been executed, i.e., “lackluster management of its contracts.” (ORA Opening Brief, p. 228.) ORA then equates this with “corporate malfeasance.” (*Id.*) However, ORA does not cite record evidence that would allow us to draw that conclusion. ORA admits that some level of breach of contract damages is both inevitable and reasonable, but, in effect, claims that the level of expense embedded in PG&E's Account 925 request clearly exceeds that level. Again, the record does not allow us to draw this conclusion. Finally, there is no evidence to support the argument that allowing breach of contract costs in rates will yield an inadequate incentive for PG&E to reasonably manage its contracts.

It is certainly possible for PG&E's actions with respect to any given contract to be unreasonable, in which case the costs of any consequent damage award or settlement should not be paid by ratepayers. However, given PG&E's general showing that breach of contract costs can be considered reasonable costs of doing business, we will not require PG&E to make an affirmative showing on reasonableness of each of the awards and settlements at issue in this GRC. In the event of any future ratemaking proceeding in which PG&E's breach of contract expenses are at issue, PG&E should be prepared to demonstrate the reasonableness of all underlying expenses as part of its initial showing without mere reliance on the general proposition that breach of contract costs are inevitable.

Based on the foregoing, it is reasonable to include a forecast of breach of contract expenses in the 1999 Account 925 forecast. Upon reviewing the historical recorded costs for breach of contract expenses, we find that the 1994 expense of $42,656,240 is an outlier value that should not be included in the average value used to forecast Account 925 expenses. This expense was more than quadruple the next highest value of the five years from 1993 through 1997. The 1996 constant dollar expenses for 1993, 1995, 1996, and 1997 were $6,298,336, $9,277,949, $2,935,027, and $4,317,112, respectively. The average for these four years is $5,707,106. The five-year average embedded in the Account 925 forecast is $13,096,932. To properly reflect the removal of the 1994 recorded expense, the difference between the four-year and five-year averages, $7,389,826, should be reflected as a downward adjustment to the forecast for Account 925.

9.2.2.7.4 Officers' and Directors' Insurance

During the proceeding PG&E agreed that a component of officers' liability insurance should be allocated to affiliates based on relative asset values between PG&E and its affiliates. PG&E reduced the allocation to the utility from $1.25 million to $799,000. This proposal is uncontested and will be adopted.

TURN, joined by Enron, recommends that 50% of the cost of officers' and directors' insurance allocable to the utility be further allocated to shareholders as a below-the-line expense. Thus, they recommend that PG&E be authorized to recover $400,000 of this insurance cost from ratepayers. They reason that a portion of the utility cost should be borne by shareholders because the insurance is intended to provide benefits for shareholders. TURN and Enron note that this recommendation is consistent with the treatment of the issue in Edison' 1995 GRC. (D.96-01-011, 64 CPUC2d 241, 319.)

We adopt a 50% allocation to shareholders as an appropriate reflection of the benefits received by shareholders from this insurance.

9.2.2.7.5 Tree-Related Claims and Related Costs

TURN proposes three reductions to the Account 925 base estimate to remove the impact of certain claims and related costs for tree-related damages. First, TURN rejects inclusion of the costs of criminal fines, asserting that these expenses cannot conceivably be considered reasonable. TURN notes that PG&E apparently excluded the costs of fines associated with the Nevada County fires, but included the costs of fines and settlement payments in other jurisdictions. TURN estimates that removing these costs would reduce the forecast by $66,000 given the use of an averaging forecast method. Second, TURN contends that the costs of restitution and damages associated with fires that resulted in findings of criminal behavior should be excluded from rate recovery. Third, TURN proposes a reduction to reflect the fact that because PG&E has increased vegetation management efforts, it is reasonable to expect that those efforts will be successful and will reduce tree-related and fire-related injuries and damages costs. TURN therefore recommends a 50% reduction in tree-related claims, which, based on the averaging forecast method, would reduce the Account 925 forecast by approximately $2 million before a further adjustment to avoid double-counting of fire damages is made.

PG&E does not contest the first two components of TURN's proposal for tree-related damages. However, PG&E rejects the proposed reduction for anticipated gains of the vegetation management program. PG&E argues that even though tree-related claims may decline, "some other type of claim will arise with greater frequency in the future." (PG&E Opening Brief, p. 236.)

Discussion

As we noted earlier in this decision, PG&E has embarked upon a major enhancement to its tree-trimming program in recent years at considerable ratepayer expense. PG&E does not take issue with the underlying premise of TURN's recommendation, i.e., that tree-related claims will decline with enhanced tree trimming efforts. PG&E simply contends that other unspecified costs will arise to take their place. PG&E's proposal to deny ratepayers any of these gains from the enhanced tree-trimming program is untenable and is therefore denied. In the absence of a more rigorous quantification of the effects of the tree trimming program, TURN's proposal for a 50% reduction based on historical costs is reasonable. The record supports an adjustment of $1.584 million, including TURN's proposed adjustment for fines and settlement payments, which we hereby adopt.

9.2.2.7.6 Campbell Complex Fire

In its Results of Examination report, ORA recommended an adjustment of $1.6 million in connection with the settlement of a 1990 lawsuit. The suit resulted from a fire allegedly caused by a tree in close proximity to a 500 kV transmission line. PG&E booked approximately $8 million to Account 925 during the years 1994 to 1997. ORA recommends that the amount be removed from Account 925 because transmission expenses fall under FERC jurisdiction as a result of electric industry restructuring. Based on the use of five-year averaging, ORA recommends removal of one-fifth the total amount booked to Account 925, or $1,602,500. ORA recognizes that it inadvertently made this adjustment twice in its opening brief, and made an appropriate correction in its reply brief.

PG&E rejects ORA's proposal for the Campbell fire with the argument that, despite the fact that transmission lines are under FERC jurisdiction, direct assignment of these costs is not appropriate unless all Account 925 costs are directly assigned. PG&E does not point to evidence that supports this argument, and inclusion of transmission-related costs in distribution rates is clearly not appropriate. ORA's recommended adjustment is therefore adopted.

9.2.2.7.7 Other Judgments

As stated in its reply brief, PG&E agrees to a $0.9 million reduction of the Account 925 estimate to reflect removal of damage expenses relating to the Rough and Ready fire, where PG&E was found guilty of criminal negligence, and a successful sex discrimination claim against PG&E. This reduction is reasonable and necessary, and is hereby adopted.

9.2.2.7.8 Wave 1 Divestiture

PG&E removed the cost of providing injuries and damages coverage for its Wave 1 power plants from its forecasts. As noted earlier in connection with

Account 924, ORA recommends leaving the costs associated with PG&E's Wave 1 plants in A&G expenses and allocating those costs to the generation function through the cost unbundling process. However, ORA recommends that if the cost of Wave 1 plants is excluded, its Account 925 forecast recommendation should be reduced by $2,234,000. ORA has not demonstrated that imputing directly assignable costs is necessary, and its proposal is therefore denied.

9.2.2.7.9 Allocation to Construction

ORA used a five-year average of historical data to determine the amount of workers compensation and medical payments allocated to construction. PG&E used a pro-forma percentage to capitalize workers' compensation and medical payments. ORA's five-year average recommendation, which is equivalent to a 30.94% allocation factor, is reasonable because it is consistent with the forecast methodology for this account, and is therefore adopted.

9.2.2.8 Account 926 - Pension and Benefits

In this section, we consider disputed issues pertaining to Account 926 which were addressed by PG&E and ORA in briefs. PG&E and ORA have minor differences regarding PG&E's vision plan, dental plan, group life insurance, flexible compensation program, savings fund plan, employee relocation program, and transit program. For these subcategories of Account 926, we accept PG&E's estimates as having greater record support.

9.2.2.8.1 Pension Funding

PG&E offers a tax-qualified pension plan which provides benefits to employees upon retirement based on years of service, salary, and age at retirement. PG&E recommends the use of what it calls the "normal cost" method to determine the pension fund contributions to be reflected in revenue requirements. PG&E states that under the normal cost method, the forecast pension cost is based on the cost of benefits earned by employees in the current year. PG&E favors this method because it assertedly produces a stable contribution and the cost remains level as a percentage of payroll in the absence of major plan changes. PG&E also claims that it ensures that any special benefits attributable to early retirement benefits, cost of living adjustments for retirees, or other increases to benefits earned in the past would not be included in the current expense. PG&E further asserts that the normal cost method ensures that current customers will pay the cost of benefits earned by employees in the course of providing service to those customers. PG&E thus believes it is consistent with the basic cost-of-service ratemaking tenet of assigning the costs of providing current service to the year in which such service is provided. Finally, PG&E notes that the State of California’s own pension fund uses the “Entry Age Normal Cost Method.”

ORA urges rejection of PG&E's normal cost approach in favor of what it calls the “Internal Revenue Service / Employee Retirement Income Security Act (IRS / ERISA) contribution method.” ORA states in Exhibit 342 that this is “the method the Commission has adopted for all utilities' pension ratemaking” in Ordering Paragraphs 1 and 2 of D.88-03-072, D.89-12-057, and D.91-12-076.[36]

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36 Ordering Paragraph 1 of D.88-03-072 directed *telephone* utilities to use "the current aggregate cost method, or cost approach, which normalizes pension cost over the employee's service period for ratemaking and accounting purposes." Ordering Paragraph 2 rejected the use at that time of Financial Accounting Standards Board (FASB) Statement No. 87, which employs the unit credit method, or benefits approach. (27 CPUC2d 550, 557.)

In D.89-12-057, in PG&E's test year 1990 GRC, the Commission rejected the DRA's proposal to apply FASB Statement No. 87 to the determination of PG&E's pension plan revenue requirement. Instead, based on its findings in D.88-03-072, the Commission stated that PG&E's "contribution approach" was reasonable. (34 CPUC2d 199, 262-263.)

Footnote continued on next page

ORA claims that the trend for normal costs is increasing while actual cash contributions and accounting costs are decreasing. According to ORA, this is because the normal cost method eliminates amortized amounts, which include the effect of plan changes, actual investment performance in excess of assumed performance, and changes in actuarial assumptions. ORA contends that the revenue requirement resulting from the normal cost method does not reflect the existing plan or the funding status of the pension obligation. ORA claims that PG&E's normal cost method is unfair to shareholders because PG&E could incur tax liabilities if it makes excess pension fund contribution, and that it is unfair to employees and ratepayers because "PG&E will be compelled to divert *$60 to $70 million* dollars (sic) in ratepayer funding to nonpension uses." (Exhibit 342, p. 9D-6rev; emphases in original.)

Discussion

During the course of the proceeding, PG&E reduced its initial proposal for pension funding by $72 million. PG&E conceded that it could not make a tax-deductible contribution to the pension trust fund in the test year. No party contests the approximately $3 million in pay-as-you-go pension costs requested by PG&E that cannot be paid out of the pension trust. Thus, there is no revenue requirement issue with respect to pension funding in this test year 1999 GRC. However, PG&E and ORA strongly disagree on the appropriate pension funding methodology to be used for future ratemaking. In addition, in granting rehearing of the test year 1996 GRC decision with respect to the issue of pension

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In D.91-12-076, in Edison's test year 1992 GRC, the Commission provided that what was referred to (but not otherwise defined) as the "ERISA / IRC method" for calculating pension costs should be continued in the future. (42 CPUC2d 645, 684.)

funding policy, D.98-12-096 provided that the rehearing of this issue would be addressed in this GRC. Thus, the issue of pension funding policy is ripe for resolution, even though we recognize that future ratemaking proceedings may find a need for further consideration.

ORA objects to PG&E's pension funding approach because of its concerns that PG&E will incur substantial tax liabilities from overfunding its pension trust, and that PG&E will be forced to divert ratepayer-supplied funds that are intended for pension benefits. However, PG&E states that it will only make tax-deductible contributions to the pension trust, and it has reduced its funding request in this GRC by $72 million precisely because of the taxation issue. Given PG&E's position, ORA has not demonstrated why we should share its concerns about PG&E's pension funding approach.

Nor has ORA demonstrated how or why its approach is superior to PG&E's normal cost approach. ORA has not addressed PG&E's claim that the normal cost method better matches costs with the current year revenue requirement. ORA's claim that D.88-03-072, D.89-12-057, and D.91-12-076 adopted, in perpetuity, the IRS / ERISA contribution method for all utilities is untenable. The ordering paragraphs of D.88-03-072 apply only to telephone utilities, and the other two decisions apply to PG&E and Edison respectively. Significantly, ORA has not demonstrated that D.89-12-057 supports its position. In the absence of any significant demonstrated fault in PG&E's approach, and any showing that the Commission has consistently adopted its own approach, ORA's recommendations lack adequate support. Based on the record of this GRC, we are left to repeat our discussion in the last GRC, as it is equally applicable here:

> "DRA has not adequately supported its position with regard to funding policy. DRA does not explain why it chose the benchmarks

> it did or why the midpoint of those benchmarks is sensible. We will adopt PG&E's proposal to set pension costs according to the benefits accruing to current employees, which PG&E refers to as 'normal cost.' This funding level may result in contributions that are ultimately too high if PG&E further reduces its workforce. If this turns out to be the case using the earnings assumptions we adopt here, we will make appropriate adjustments if and when it has a subsequent general review of its rates. If such a review does not occur within three years, PG&E shall file an advice letter no later than December 31, 1999 proposing ratepayer refunds, if any are appropriate pursuant to this discussion." (D.95-12-055, 63 CPUC2d 570, 594.)

In view of the foregoing discussion, we affirm that the normal cost method, limited by the maximum tax-deductible contribution under IRS regulations, as an appropriate pension funding method for PG&E to use. The concern we expressed in the last GRC decision regarding potential future excess contributions remains. Therefore, if PG&E has not undergone a general review of rates that includes its pension contributions in the next three years, we direct PG&E to file an advice letter no later than December 31, 2002 proposing ratepayer refunds, if any are appropriate pursuant to this discussion.

9.2.2.8.2 Long-Term Disability Payments (LTD)

In November 1992, the FASB issued Statement of Financial Accounting Standard No. 112 (SFAS 112). It requires employers to adopt accrual accounting for post-employment benefits, including LTD. SFAS 112 does not allow amortization of the transition obligation created by the accrual requirement over a period of years. Instead, it requires full recognition of the SFAS 112 liability upon its adoption. PG&E adopted SFAS 112 effective January 1, 1994. In the 1996 GRC, the Commission took note of the accounting change and the fact that it increased PG&E's revenue requirement. (D.95-12-055, 63 CPUC2d 570, 593.)

In this GRC, parties dispute PG&E’s proposal to recognize the amortization of its SFAS 112 transition obligations related to LTD. PG&E claims that its proposal is simply a continuation of the authorization it received in D.95-12-055. ORA and FEA claim that D.95-12-055 did not authorize amortization of the transition liability. ORA and FEA further claim that amortization is inconsistent with SFAS 112 and violates the prohibition against retroactive ratemaking. Accordingly, they recommend an adjustment of $8.5 million to remove the disputed expense.

Discussion

Resolution of the LTD funding dispute turns on what the Commission authorized in D.95-12-055. ORA and FEA correctly observe that this decision did not explicitly address the amortization question, and that it did not explicitly address departures from the SFAS 112 provision regarding amortization. However, as PG&E correctly observes, Exhibit 260 demonstrates that the Commission approved amortization of the liability in the 1996 GRC. In that proceeding, PG&E explicitly requested amortization of the unfunded LTD liability. The 1996 GRC decision provided that proposals not specifically addressed were presumed to be granted as PG&E requested. (D.95-12-055, 63 CPUC2d 570, 583.)

Since the Commission has already approved amortization of the transition obligation, and the decision was not challenged on the question of retroactive ratemaking, there is no question of retroactive ratemaking or inconsistency with SFAS 112 here. PG&E's request to continue authorized ratemaking treatment of the transition cost is justified, and the proposed expense adjustment of $8.5 million is therefore denied.

9.2.2.8.3 Medical Plans

PG&E's medical plan expenses include the costs of plans administered by Prudential, nine health maintenance organizations (HMOs), and several health-related programs. As shown in Exhibit 342, PG&E estimates its total medical costs for 1999 at $110.6 million in 1999 dollars, while ORA forecasts a level of $80.1 million. Both estimates exclude the agreed-upon $937,000 cost of the employee assistance plan.

PG&E developed its forecast by applying projected future trends to the estimated 1997 cost for the individual components of the medical plan. ORA asserts that because it developed its forecast later, it was able to use actual 1997 data and actual trends from 1998, and therefore present a more reliable forecast.

Discussion

PG&E takes issue with ORA's proposed LTD adjustment of $6.8 million for the 1997 medical expenses. PG&E claims that the 1997 LTD costs were paid out of the LTD trust, and were not included in the 1997 recorded medical expenses. PG&E claims that ORA's adjustment would result in double counting. We accept this explanation.

PG&E also disputes ORA's calculation of a negative trend rate for PG&E's self-insured medical plan expenses and a trend rate of less than 3% for HMO plan expenses. In addition, PG&E finds ORA's calculated medical trend factors to be inconsistent with trend estimates of 8% from PG&E's self-insured medical plan provider, 7% from Kaiser, 3% from PG&E's mental health and substance abuse provider, and 12% from PG&E's prescription drug provider.

ORA contends that in some cases, PG&E and its vendors overestimated medical cost increases. However, ORA's testimony on this point and on medical cost trending in general is very limited, and PG&E has demonstrated that ORA's analysis was flawed. ORA's testimony consists simply of a statement that "ORA's forecasts [are] one year to four months more recent than PG&E's forecasts. ORA believes that this makes ORA's recommendation superior to PG&E's because as time goes by, information about events becomes more accurate and definitive." (Exhibit 342, p. 9D-5rev.) As an example of a flaw in ORA's analysis, PG&E determined that ORA failed to adjust the 1997 managed care payments number to reflect PG&E's adoption of a prescription drug program on January 1, 1997. This program removed drug costs from the managed care program, thereby reducing the 1997 total for managed care costs. Thus, ORA overstated a negative cost trend.

Where ORA estimates overall 1999 medical costs of $81 million including employee assistance program costs, PG&E has shown that its recorded medical costs were $87.1 million in 1996 and $93.1 million in 1997. ORA's medical cost recommendation for 1999 is less than recorded costs for 1996. While we recognize ORA's concerns about the reliability of PG&E's recorded data, we find that ORA has not provided adequate support for its forecast of medical expenses. In addition, PG&E has demonstrated that ORA's approach is flawed in certain respects as discussed above. Accordingly, we adopt PG&E's estimated medical costs.

9.2.2.8.4 Post Retirement Benefits Other Than Pensions (PBOPs)

9.2.2.8.4.1 Test Year Estimates

PG&E requests estimated PBOPs medical and life insurance costs of $34.6 million and $6.7 million, respectively. These amounts were calculated by Towers Perrin, the plan's actuary. ORA recommends cost estimates of $23.8 million and $6.2 million for PBOPs medical and life, respectively. ORA did not provide testimony explaining its proposed amounts. The record supports adoption of PG&E's test year forecast.

9.2.2.8.4.2 ORA's Refund Proposal

ORA recommends a one-time refund to ratepayers of $12.8 million in alleged overcollection of PBOPs costs. ORA's recommendation is based on its finding that:

> "PG&E's 1997 contributions, excluding 1994 Voluntary Retirement Incentive Plan ('VRI') and the amortization of the 'regulatory assets' [FN omitted], were less than the GRC authorized PBOPs costs [FN omitted]; therefore, PG&E must be diverting ratepayer funds for PBOPs to nonPBOPs uses. A refund is mandated under Ordering Paragraph No. 4, D.92-12-015 for these ratepayer dollars which were not placed into a PBOPs trust." (Exhibit 342, p. 9D-7rev.)

As indicated above, the recommended refund pertains to 1997 PBOPs contributions. We note, however, that at p. 9D-1rev of Exhibit 342, ORA indicates that the proposed refund pertains to 1996 through 1998 PBOPs. At p. 9D-7rev., ORA indicates that the refund pertains to 1997 and 1998 PBOPS. At p. 235 of its opening brief, ORA indicates that the refund is for 1996 and 1997 overcollections. While the record is ambiguous, we proceed with the assumption that ORA's recommendation pertains to 1997 contributions.

PG&E contends that ORA's calculation fails to account for the fact that the PBOPs medical gross expense authorized in the 1996 GRC should be reduced by the capitalized portion of the PBOPs expenses. PG&E also contends that ORA did not include all contributions that were made to the trust. In addition, PG&E contends that in 1996 there was an undercollection of $12,685,000 for PBOPs medical and an overcollection of $223,000 for PBOPs life. PG&E asserts that instead of being overcollected by $12.8 million, 1996 and 1997 PBOP contributions net of the capitalized portion are undercollected by $8 million compared to the amount authorized in the 1996 GRC.

Discussion

In its opening brief, ORA states that the dispute over its proposed refund stems from ORA's position that PG&E improperly and without authorization created regulatory assets which it assertedly added to trust contributions in 1996 and 1997. The issue of regulatory assets is discussed below in Section 9.2.2.8.5. As we determine there, ORA has not demonstrated that PG&E is requiring ratepayers to fund regulatory assets.

As noted above, PG&E claims that ORA's refund calculation fails to recognize that the PBOPs medical cost should be reduced to reflect allocations to capital. ORA has not fully supported its PBOPs refund calculation. Finally, ORA has not shown that a PBOPs refund is warranted at this time. PG&E appears to acknowledges that a true-up is necessary, but in effect claims this is not the appropriate forum for accomplishing a true-up. PG&E notes that PBOPs expenses are to be trued up on a cycle that covers the three years 1996, 1997, and 1998 pursuant to its 1993 GRC decision and associated advice letter filing (Advice Letter 1956-G / 1583-E). We concur that this is not the appropriate forum for a true-up.

9.2.2.8.4.3 ORA's Additional Refund Proposal

In its opening brief, ORA argues (at pp. 234-235) that PG&E has not complied with Ordering Paragraph 8 of the 1996 GRC decision. (D.95-12-055, 63 CPUC2d 570, 635.) That order directed PG&E to file an advice letter to reduce revenue requirements by the amount of PBOPs overcollections accrued up to December 31, 1995. The Commission modified the PBOPs discussion in D.95-12-055 by providing that the advice letter filing should reflect allocations adopted in the previous GRC decision. (D.96-05-010, 66 CPUC2d 137, 635.) PG&E filed the advice letter (Advice Letter 1956-G / 1583-E), but ORA contends that PG&E did not fully carry out the order in D.95-12-055. ORA asks that PG&E be ordered to refund what it contends is the remainder of the amount due.

ORA has not demonstrated that its proposal is supported by record evidence in this GRC. In any event, the proposal is procedurally defective in that PG&E has not had an opportunity to present rebuttal testimony in response to the proposal. We will not adopt it.

9.2.2.8.5 Regulatory Assets and Liabilities

The Commission has stated that a regulatory asset is the recording of the utilities' costs not currently recoverable for ratemaking purposes. (D.92-12-015, 46 CPUC2d 499, 536.) ORA contends that ratepayers have been funding regulatory assets which were calculated using assumptions that were rejected by the Commission. Specifically, ORA argues that PG&E used discount rates of 8% and 7.25% to determine test year pension costs, while the Commission explicitly adopted 9% in D. 95-12-055. ORA recommends that PG&E be ordered to discontinue this accounting practice and refund to ratepayers the amount of regulatory assets that have been incorporated into tariffs.

PG&E disputes ORA's analysis and recommendation, contending that they are based on a fundamental misunderstanding of regulatory assets. PG&E points to its rebuttal testimony that regulatory assets represent the capitalization of an incurred cost not yet allowed in rates, and are not funded as ORA claims. PG&E further claims that the Commission recognized the operation and recording of regulatory assets in a generic PBOPs investigation. (*Id.*) Finally, PG&E claims that it is not seeking recovery of any amounts carried on its books as regulatory assets in this GRC. ORA has not shown otherwise. Thus, the issue of the rate recovery of pension contributions carried as regulatory assets is not ripe for resolution in this GRC.

9.2.2.8.6 Other Accounting Issues

ORA's Account 926 witness raised several other issues related to alleged accounting errors committed by PG&E. Among other things, ORA faults PG&E accounting practices with respect to the SAP business system and financial reporting requirements. ORA suggests corrections in PG&E's accounting records and asserts that PG&E did not reconcile certain accounts. ORA urges "extreme caution" in the use of SAP information, but notes that this recommendation has no direct dollar impact.

PG&E witness Dales, a corporate accounting manager at PG&E Corporation and a Certified Public Accountant (CPA), offered testimony in rebuttal to ORA's concerns. PG&E claims that ORA's criticisms of PG&E's accounting practices are based on a "fundamental misunderstanding of financial accounting requirements." (PG&E Opening Brief, p. 249.) PG&E emphasizes the fact that ORA's witness on PBOPs and related Account 926 accounting issues is an economist by training and is not a CPA. While we do not accept each of PG&E's criticisms, we give greater weight to the testimony of PG&E's accounting witness on disputed accounting issues which were addressed by both witnesses. Thus, we find that PG&E has, in general, adequately responded to ORA's concerns raised during the litigation of Account 926 with respect to the new SAP business system. We generally agree with ORA's contention that PG&E's SAP-generated balances warrant scrutiny. However, to the extent SAP-related data is relied upon to support PG&E's Account 926 showing, PG&E has justified its use.

We further address SAP issues in Section 9.12, where we address ORA's Report On Results Of Examination

9.2.2.8.7 Workforce Reduction

PG&E points out that in the development of the results of operation (RO) computer model used to develop revenue requirements, ORA makes an adjustment to Account 926 to reflect an assumed workforce reduction. As shown in the comparison exhibit, ORA reduces its Account 926 estimate by 21.46%. There is no record evidence supporting an adjustment to Account 926 based on test year workforce reductions by PG&E. Accordingly ORA's proposed workforce adjustment to Account 926 will not be accepted.

9.2.2.8.8 Allocation Issues

9.2.2.8.8.1 Allocation to Construction

PG&E uses an allocation factor of 29.58% to allocate pensions and benefits to construction, while ORA recommends a factor of 30.98%. ORA's recommendation would reduce the Account 926 estimate by $3.9 million.

PG&E's recommended allocation factor is based on the use of straight-time productive labor, while ORA uses FERC Form 1 information. ORA's approach thus includes all labor related expenses, including premium pay, hiring hall labor, PIP expenses, and other items. PG&E contends that its approach is more accurate because straight-time productive labor costs are used to determine the actual amounts of pensions and benefits to be paid.

ORA relies on FERC Form 1 data because of its concerns that PG&E's estimate relies on SAP data. As an example of its concern regarding the reliability of SAP-generated information, ORA points out that PG&E initially presented an erroneous capitalization rate of 8.3% in this GRC. However, SAP data are used in the FERC Form 1 filing as well, and in any event ORA has not shown that PG&E's capitalization error was the consequence of implementing the new SAP business system.

ORA does not dispute PG&E's contention that straight-time productive labor is the basis for determining pensions and benefits. We find that it is appropriate to use a capitalization rate that reflects this basis. We therefore adopt PG&E's recommendation for a capitalization factor of 29.58%.

9.2.2.8.8.2 Allocation to Diablo Canyon

PG&E allocates a fixed amount of pensions and benefits to Diablo Canyon, based on the amount adopted in D.97-05-088, including an escalation rate of 1.5%. PG&E takes the position that D.97-05-088 determined a certain amount of Diablo Canyon-related pensions and benefits to be included in setting the Diablo Canyon rates, and that the amount so determined should be attributed to Diablo Canyon in this GRC.

ORA points out that the Diablo Canyon allocation adopted in D.97-05-088 is based on 1995 costs. ORA contends that using 1995 costs to separate Diablo Canyon costs from the 1999 forecast of employee benefits is illogical and improper, given the significant increases in employee benefits costs forecast by PG&E. TURN recognizes that PG&E has reduced its pension funding forecast and corrected its capitalization error since ORA made this statement, and that the dollar impact of this dispute has been reduced from nearly $18 million to approximately $1 million. Still, TURN asserts PG&E's approach is conceptually wrong.

PG&E has not demonstrated that adoption of an implicit estimate of employee benefits in the Diablo Canyon ratemaking proceeding prevents consideration of a more up-to-date determination of reasonable allocations in this GRC. PG&E's approach allocates unreasonably low amounts to Diablo

Canyon. ORA's method, based on the percentage of total O&M labor, is therefore adopted.

9.2.2.8.8.3 Allocation to Affiliates

PG&E's proposed allocation of pension and benefits costs to affiliates is based on the 1997 recorded labor burden of 19.28%. ORA proposes an allocation factor of 36.85%, although this appears to be based on calculations made before PG&E reduced its forecast for pensions contributions. PG&E's allocation is reasonable and is therefore adopted.

9.2.2.9 Account 927 - Franchise Fees

Payments made to city and county authorities in compliance with franchise agreements, ordinances, or similar requirements are included in Account 927. PG&E computed franchise fees by using its RO model. The amount of fees is estimated by applying the franchise factor to the revenue requirement excluding franchise fees and uncollectibles and adding the resulting calculation to the revenue requirement. No party contests this method for estimating franchise fee expense or the factors used.

CAL-SLA suggested that it would be appropriate for PG&E to produce a report on franchise fees similar to a report that is prepared by SDG&E. PG&E has agreed to provide such a report in the future. Specifically, PG&E agrees to file an annual report by June 30 of each year on payments made for the immediately preceding calendar year. The report will be in the format recommend by CAL-SLA and include columns headed "city or county," "payment amount," and "gross revenue amount."

We accept this agreement, with the following provision. We do not intend to use dockets such as this GRC proceeding to accommodate such reports on an ongoing basis. Instead, we direct PG&E to submit the reports to the Director, Energy Division, and to serve a copy on CAL-SLA and any other party who so requests. In addition, to avoid the problem of establishing compliance requirements that outlive their usefulness, we will sunset this reporting requirement after five years.

9.2.2.10 Account 928 - Regulatory Expense

Account 928 includes expenses incurred in paying filing fees related to formal cases, hearings, and investigations before regulatory commissions. PG&E has reduced its forecast to $50,000, and there are no remaining issues with respect to this account. We adopt PG&E's forecast.

9.2.2.11 Account 930 - Miscellaneous

9.2.2.11.1 Introduction

Both PG&E and ORA revised their forecasts for Account 930 on several occasions during the course of the proceeding. Among other things, PG&E and ORA agree on the inclusion of $78 million in costs for energy efficiency, conservation, and renewable technology payments required by AB 1890. Other items in the account include dues and subscriptions, bank fees, expenses related to services to bondholders and stockholders for transfer agent, registrar, and trustee activities, and directors' fees and expenses. As shown in the comparison exhibit, the remaining differences between PG&E and ORA total $7.9 million. The following sections (Sections 9.2.2.11.2 through 9.2.2.11.6) address the components of this difference. Except as provided in these sections, we adopt PG&E's proposals for Account 930.

9.2.2.11.2 Bain and Company (Bain) Costs

PG&E's forecast for Account 930 reflects $1.83 million in consulting costs paid to Bain in 1997. ORA proposes that this amount be excluded for the purpose of forecasting 1999 expenditures.

Even though the Bain consulting effort was a one-time cost in 1997, PG&E takes the position that the cost of the business process improvement work performed by Bain should not be excluded from this account for the purpose of estimating 1999 expenditures. PG&E maintains that such efforts are a regular part of its business. PG&E carries out such work to improve its systems and reduce costs, and expects that it will continue to use consultants for these purposes in the future.

PG&E contends that even though the specific fees paid to Bain were a one-time cost, it is reasonable to expect similar costs to be incurred in the future. However, we still find ORA's adjustment to be appropriate. Bain participated in PG&E's Smart Spending Program and Overhead Optimization Study. These initiatives were expected to produce substantial savings in 1999, yet, as we noted in connection with Account 920, PG&E has not demonstrated that it reflected such savings in its GRC estimates. Including consulting fees expended to obtain cost reductions in a GRC forecast while excluding the associated cost savings from the GRC forecast is fundamentally unfair to ratepayers, because it requires ratepayers to pay for the cost of implementing cost reductions while allocating all of the benefits of the cost reductions to shareholders. ORA's proposed adjustment is reasonable under the circumstances and is therefore adopted.

9.2.2.11.3 SAP Adjustment

As discussed below in Section 9.12, we adopt ORA's proposal for a $4 million credit to reflect anticipated savings from implementation of the SAP business system. After allocations to capital and Diablo Canyon, ORA's savings estimate is $2,694,240, before constant dollar adjustments. For the reasons discussed in Section 9.12, this adjustment is appropriate, and will be therefore be reflected in Account 930.

9.2.2.11.4 Surcharge Adjustment for Affiliates

The affiliate transactions rules adopted in D.97-12-088 require a 5% markup on labor costs charged to affiliates. As noted earlier, PG&E incorporates the 5% surcharge by increasing the number of labor hours allocated to the affiliates (excluding the holding company) by 5% over what is indicated by the Effort Study. For revenue requirement purposes, PG&E reflects the 5% surcharge as a reduction to the Account 920 revenue requirement estimate. PG&E contends that this approach is straightforward. ORA contends that the surcharge should be reflected in Account 930 because it is the account indicated for this purpose under the FERC USOA, and PG&E records the markup in Account 930 in its books.

We find ORA's argument persuasive and therefore adopt its approach. ORA's recommended Account 930 forecast initially included $510,215 to reflect the 5% markup. ORA notes that the 5% markup adopted in D.97-12-088 only applies to labor costs, and that ORA witness Harpster incorrectly applied the 5% markup to total charges from PG&E to affiliates. A 5% markup on Account 920 labor costs is $211,662. Therefore, PG&E's Account 930 recommendation should be decreased by $211,662.

9.2.2.11.5 Divestiture Costs

PG&E's March Update forecast of Account 930 included $3,580,700 in generation divestiture costs, reflecting recorded 1997 costs. PG&E later reduced this request by $712,000. ORA contends that the only generation divestiture activity scheduled for 1999 was the divestiture of four Wave 2 power plants, which PG&E expected to complete in the second quarter of 1999. ORA also contends that PG&E did not reflect the cost savings resulting from the Wave 2 divestitures in its 1999 forecast. ORA takes the position that it is inappropriate to include the cost of divestiture efforts in the 1999 GRC forecast while excluding the cost reductions resulting from the divestitures from the same forecast. ORA recommends the removal of all power plant divestiture costs from Account 930.

PG&E claims that divestiture costs will continue through 2000, but we find inclusion of these costs to be inappropriate for the reasons explained by ORA. ORA's adjustment is therefore adopted.

9.2.2.11.6 Shareholders Meeting

PG&E has allocated 65% of the costs of PG&E Corporation's annual shareholders meeting to PG&E. ORA does not include any of these costs in its Account 930 forecast. Consistent with our treatment of shareholder services costs in Section 9.2.2.2.5.4.7, where the arguments are similar to those advanced here, we adopt the midpoint of the allocation recommendations, or 32.5% to the utility.

9.2.2.12 Account 931 - Rents

As shown in the comparison exhibit, PG&E and ORA agree that the amount estimated for this account should be zero. No other party addresses this account. As discussed earlier in connection with Account 921, PG&E charges A&G-related rents to Account 921.

9.2.2.13 Account 935 - General Plant Maintenance

Account 935 includes the costs of maintaining PG&E-owned communications equipment. There is no disagreement among the parties with respect to this account. We adopt PG&E's estimate.

9.2.3 Customer Accounts Expenses

9.2.3.1 Introduction and Preliminary Matters

The following table, abstracted from the comparison exhibit (pp. A-25 and A-49), shows PG&E's and ORA's recommendations for customer accounts. It does not reflect PG&E's proposal, discussed in Section 12.1, to remove restructuring implementation costs from its GRC request for Accounts 903 and 905. Under PG&E's new business system, supervision costs are no longer recorded in Account 901. Neither party forecasts costs for this account.

PG&E's and ORA's Positions on
Electric and Gas Customer Accounts Expenses
(1996 Dollars in Thousands)

Account	Description	PG&E	ORA	Difference
902	Meter Reading			
	Electric	$39,532	$34,737	$4,795
	Gas	31,616	28,163	3,453
	Subtotal – Electric and Gas	71,148	62,900	8,248
903	Customer Records & Collection			
	Electric	138,877	81,296	57,581
	Gas	102,821	63,717	39,104
	Subtotal – Electric and Gas	241,708	145,013	96,695
905	Miscellaneous			
	Electric	13,932	8,306	5,626
	Gas	4,603	0	4,603
	Subtotal – Electric and Gas	18,535	8,306	10,229
	Totals			
	Electric	192,341	124,339	68,002
	Gas	139,040	91,880	47,160
	Combined Totals	$331,381	$216,219	$115,162

TURN and Weil concur with ORA's meter reading expense forecast of $62.9 million, and their combined total customer accounts recommendations are similar to ORA's. TURN and Weil propose somewhat lower amounts for Account 903 ($144.0 million and $144.6 million, respectively) than ORA

($145.0 million). Enron proposes significantly lower meter reading expenses of $49.9 million and Account 903 expenses of $136.9 million. Enron's combined total recommendation for customer accounts is $198.3 million, or approximately $133.1 million less than PG&E's forecast of $331.4 million.

Before addressing individual customer accounts, we consider Enron's arguments pertaining to the impact of industry restructuring and the advent of competition on the consideration of customer accounts expenses. Enron contends that services such as metering and billing are acknowledged to be competitive, and that if PG&E is allowed to recover more than what is needed to provide monopoly distribution service, those revenues could be used to disadvantage competitive providers of services. Enron notes that in the previous GRC, the Commission denied funding for customer related programs where a potential existed for shifting the cost of services tailored for specific customer classes to all ratepayers. (D.95-12-055, 63 CPUC2d 570, 598-99.) Enron is particularly concerned about the potential for improper cost shifting in this GRC because of the large increase in customer related revenues sought by PG&E. Enron calculates PG&E's combined request of $331.4 million as 75% more than the combined amount authorized in the 1996 GRC. With the shift of Revenue Cycles Services to the competitive arena, Enron expects "from a basic, common sense standpoint" customer accounts revenue requirements to decrease.

As we found in the policy section of this decision, careful scrutiny of PG&E's requests in this GRC is warranted for a host of reasons. These include the advent of competition and the importance of avoiding inappropriate subsidization of competitive activities. The sheer magnitude of the customer accounts increases sought by PG&E also constitutes a call for such scrutiny. However, we observe that the record of this proceeding does not support a finding that PG&E's utility responsibilities in the area of customer account activities will be diminishing in any substantive way during the test period.

9.2.3.2 Account 902 (Meter Reading)

Account 902 includes the expenses incurred in the reading of electric and gas revenue meters. In the last GRC, the Commission authorized meter reading expenses of $20.9 million for the electric department and $17.7 million for the gas department, or a total of $38.5 million. PG&E's combined electric and gas forecast of $71.1 million in this GRC is based on 1997 recorded expenses, adjusted by an additional $940,000 for load forecasting and a decrease of $1.3 million for identified savings. ORA uses a three-year average to develop its forecast of monthly meter reading costs, and adds amounts for single meter reads, load forecasting, supervision, and other. Enron uses a five-year average and adjusts for supervision costs.

In its initial application showing, PG&E pointed to employee turnover since 1995 and the loss of experienced meter readers as a significant driver of the cost increases which form the basis for its forecast. PG&E now downplays that rationale, and instead points to the implementation of its new SAP business and accounting system as the major driver of the increase in Account 902. Other reasons cited by PG&E for the increase include uncertainty associated with electric industry restructuring and the possible introduction of new meter reading technology. Finally, PG&E notes that it is required to meet standards set forth in its tariff for timely meter reading. Specifically, PG&E's Electric and Gas Rule 9, "Rendering and Payment of Bills," requires PG&E to read meters at regular intervals in order to bill customers between 27-33 days.

Discussion

We appreciate PG&E's commitment to reading customers' meters in a timely, accurate, and efficient manner. Further, we have imposed customer service standards that PG&E will be at risk for failing to meet. PG&E has justified its proposed level of spending on meter reading.

PG&E requests a substantial increase in the total meter reading expenses reflected in Account 902. In large part, PG&E is now explaining this request by reference to the cost shifts that resulted from its new SAP business system. PG&E witness Lytton asserts in rebuttal testimony that 76% of the Account 902 cost increases over 1994 levels are associated with the business system changes. Lytton further asserts that in the absence of the SAP conversion, these costs would have been recorded in other FERC accounts. PG&E claims that in all cases, the costs now reflected in Account 902 have been transferred out of the other FERC accounts, including Accounts 901 and 903.

We find the evidence supporting this argument to be convincing. If PG&E is going to rely upon implementation of a new accounting system as grounds for a near doubling of the metering costs reflected in Account 902, it is incumbent upon PG&E to track the changes and demonstrate clearly that the costs transferred to Account 902 have been removed from other specific accounts on a dollar-for-dollar basis. However, it is apparent that the 1994 data which was the basis for our decision in the 1996 GRC did not include meter reading labor or supervision booked at that time to Account 901. It is sufficient in this case for the witness to verify in a general way that the appropriate transfers have been made. Weil's analysis provides another reason to question PG&E's claim. PG&E's request is 15% higher than recorded spending in 1996, a year when the SAP system was in place and the redefinition of accounts had been completed. This is not an unreasonable forecast given the institution of direct access and the different demands it places on the customer information and meter reading function.[37]

There are other reasons why PG&E's forecast of meter reading expenses may be reasonable. Although standards governing meter reading have not changed, the transactions involved in presenting a bill, particularly in the direct access regime, have become more complex. In addition, the account will carry some of the costs associated with the Quality Assurance Program proposed by ORA and adopted in Chapter 6 above.

Relying primarily on easily verified accounting changes, PG&E has provided a cogent explanation for increases in meter reading costs in Account 902 and has demonstrated why 1997 recorded expenses yield a more accurate prediction of test year meter reading expenses than an average of the years prior to the 1996 GRC. Accordingly, we find that the use of averaging as proposed by ORA and Enron yields a less reliable forecast of reasonable expenses in the test year. We have dealt with the argument that the implementation of its new SAP business system precludes the use of multi-year averaging to forecast expenses. In connection with electric distribution O&M expenses, we determined (in Section 7.2.3.4) that the conversion to the new system was not of overriding importance and was not sufficient grounds for rejecting the use of averaging. Similarly, in connection with gas distribution expenses, we determined (in Section 8.2.4.5) that averaging may be appropriate despite PG&E's claims to the

[37] We take administrative notice of the USOA definition of Account 902 Items, which includes 20 separate operations exclusive of meter reading proper, which is included in Account 901 and is not addressed apart from Account 902 in this case.

contrary. In this case, however, averaging leads to a less cogent result, and we will not employ it. As TURN points out, PG&E's reliance on the SAP conversion to support its positions and to reject those of other parties, combined with its failure to demonstrate how all transferred account balances were reconciled in the conversion, could represents "black box" ratemaking which should not be countenanced. However, that is not the case here.

Based on the foregoing, we find ORA's forecast for meter reading for the electric department to be not well-founded. The forecast for the gas department is based on an equivalent analysis and is similarly reasonable. PG&E's forecast of combined forecast of $71.1 million for electric and gas departments is therefore adopted.

9.2.3.3 Account 903 (Customer Records and Collection)

9.2.3.3.1 Introduction

Account 903 includes the costs for customer service personnel, call centers, credit and collection activities including billing, postage, and account services expenses. ORA recommends reductions to PG&E's forecast in the areas of call centers ($12 million), account services ($27.3 million), supervision costs ($10.6 million), and CIS and IT savings ($44.5 million). Enron recommends disallowances based on its use of a five-year average (1992-1996) of recorded costs in Account 903. Weil recommends a reduction in the postage costs forecast by PG&E. TURN recommends a reduction in Account 903 to reflect PG&E's decision to reduce the operation hours of several business offices.

We consider contested issues pertaining to the Account 903 forecast in Sections 9.2.3.3.2 through 9.2.3.3.6 below. ORA's proposals regarding CIS and IT savings are addressed in Sections 9.5 and 9.6 of this decision. Except as provided in these sections, PG&E's forecast for Account 903 is justified and should be adopted.

9.2.3.3.2 Call Centers

PG&E consolidated 31 local call centers into four call centers in mid-1994. The centers provide customers with telephone access to PG&E representatives 24 hours a day, seven days a week. The 1995 storms led to additional demands on the call centers. In September 1995, the Commission adopted performance standards applicable to functions performed by the call centers. The standards require PG&E to achieve an average queue wait of less than 20 seconds, and busy signal occurrences of less than 1% during normal operations and less than 3% during outages. (D.95-09-073, 61 CPUC2d 493, 504.)

PG&E estimates that it needs $48.8 million (in 1996 dollars) for call center expenses in 1999. PG&E asserts that the Commission's "call center" standards are a primary cost driver of its call center expense estimate, and points out that the standards did not exist when it filed the 1996 GRC. PG&E also contends that when it prepared its 1996 GRC filing, the full expense requirements of its recently consolidated call centers and actual call volumes were not known. PG&E claims that it now has had four years of consolidated call center experience, has realized and reflected in its forecast numerous technology improvements, and for the first time is able to provide a realistic expense estimate for its call centers for 1999.

ORA contends that PG&E has failed to reflect cost saving measures in its forecast. Relying on data from the 1996 GRC, ORA has recommended a $12 million adjustment to PG&E's requested call center expenses. In its reply brief, ORA acknowledges that this adjustment should be reduced by $1.2 million to reflect the fact that it had not de-escalated PG&E's 1997 cost of $50 million to $48.8 million in 1996 dollars.

Discussion

PG&E has shown that data underlying the forecast of call center expenses in the 1996 GRC is less reliable than current data, and should not form the sole basis of the forecast in this GRC. In view of the changed circumstances resulting from the experience of the 1995 storms, we are persuaded that some increases in call center expenses should be expected.

We find no justification for ORA's failure to escalate the 1993 data underlying its proposed adjustment, and to thereby ignore the effects of inflation. Once this correction is made and the effects of the SAP conversion are incorporated so that an equivalent comparison of PG&E's and ORA's forecasts can be made, ORA's equivalent adjustment is $2 million. In view of PG&E's failure to demonstrate that it fully incorporated the effect of cost saving measures that it has implemented, such as interactive voice response units, we will adopt this adjustment to the forecast of call center expenses advanced by PG&E. The adopted forecast for call centers is $46.8 million.

9.2.3.3.3 Accounts Services

The Accounts Services Department performs customer services which are similar to those that call center representatives provide to residential customers, but which are tailored to commercial, industrial and agricultural (CIA) customers. The costs are now recorded in Account 903. The department also provides Customer Energy Efficiency Programs functions whose costs are recorded in Account 908, and distribution customer retention and attraction activities whose costs are recorded in Account 912. PG&E's test year estimate for

Account Services costs in Account 903 is $39 million for the gas and electric departments combined.

ORA recommends a forecast of $11.7 million for Account Services, which is equal to the amount of Account Services expenses that PG&E booked to Account 903 in 1996. Of the $27.3 million disallowance proposed by ORA, $20 million results from ORA's position that PG&E's transfer of this amount from Account 912 should be disallowed pursuant to the Commission's decision in the last GRC. In particular, the Commission denied funding for the Quality Contacts Program. (D.95-12-055, 63 CPUC2d 570, 599.)[38] ORA claims that the transferred amount corresponds to functions that were disallowed in the last GRC, and should be disallowed in this GRC. ORA also contests PG&E's request for $7.3 million in expenses for asserted inefficiencies associated with the removal of DSM functions in 1999. Enron generally agrees with ORA's position on these expenses.

Discussion

PG&E is proposing a very substantial increase in Account 903 for Account Services expenses. Figure 7-2 of Exhibit 73 shows that the combined electric and gas "basic customer service" expenses booked to Account 903 were $5.7 million in 1992, $7.2 million in 1993, $10.0 million in 1994, $7.6 million in 1995, and $11.7 million in 1996.[39] PG&E requests a level of spending which is $27.3 million

38 With respect to the Quality Contacts Program disallowance, PG&E's application for rehearing of D.95-12-055 was denied by D.98-12-096.

39 PG&E uses the term "basic services" to refer to rate and tariff functions, credit and collections, contract administration, operational work such as providing outage information, and new customer work. Without commenting specifically on each task and activity listed as a basic service in Attachment 8-1 to PG&E's rebuttal testimony

Footnote continued on next page

above the $11.7 million recorded level of spending in 1996, which itself was the highest level of the five-year period ending with 1996.

In reviewing the portions of PG&E’s opening brief that deal with this dispute, we find a well-supported description of the functions that PG&E is reasonably expected to perform on behalf of CIA customers, a claim of changed circumstances which assertedly render consideration of the 1996 GRC decision inappropriate, a demonstration that Account Services personnel perform functions which are similar to those performed on behalf of residential customers by the call centers but are more complex, and a claim that PG&E would be unable to perform basic customer services for CIA customers if ORA’s and Enron’s proposed level of spending is adopted.

PG&E has shown that Account Services Department employees are trained and able to assist CIA customers with their basic customer service needs. PG&E has also demonstrated to our satisfaction that many services performed on behalf of CIA customers are similar to those performed on behalf of residential customers but are necessarily more complex in nature. PG&E states that its forecast of $39 million “is based on the actual basic customer services work being performed by Account Services employees today and expected into 1999.” (PG&E Opening Brief, p. 272.) However, if sufficient justification for a proposed spending level consisted of a statement that “we’re spending it now and expect to spend it in the test year,” this GRC would have been a far simpler exercise than it has turned out to be.

(Exhibit 27), we generally accept PG&E's listing of functions which are central to the provision of utility distribution service and are therefore eligible for recovery in distribution rates.

The fact that industrial rate schedules are more complicated than residential rate schedules does not completely explain PG&E's request for a large increase above recently authorized or recorded expenses in Account 903. While it is apparent that greater tariff complexity will be associated with more labor-intensive customer contacts, PG&E does not allege that the complexity of CIA schedules has changed. It appears that industrial rate schedule were complicated three years ago, and remain so now.

The closest PG&E comes to substantiating its request for $39 million is its contention that "all basic customer services activities ..., some of which were previously booked to Account 912, were appropriately mapped to Account 903 beginning in 1997." (PG&E Opening Brief, p. 273.) The actual amount associated with this accounting change was about $20 million.

The $20 million shift was not made pursuant to any accounting rule, but was instead based on PG&E's determination that activities of Account Services employees that were charged to Account 912 are basic services. (Tr. v. 22, p. 2114.) PG&E explains that this determination was made in the wake of the Cost Separation Decision (D.97-08-056), the Gas Accord Decision (D.97-08-055), and the passage of AB 1890. According to PG&E, with these developments it became clear that its role is that of a utility distribution company. PG&E claims that with this clarification of its role, all basic customer services activities, including those previously booked to Account 912, are now appropriately mapped to Account 903. We find this "changed circumstances" argument to be persuasive, and are further supported in this view by the passage AB 1421.

The fact that PG&E's witness did not know specifically how much of the $39 million requested for Account Services in Account 903 was recorded in Account 912 in the years preceding the accounting change does not reduce our confidence in PG&E's showing. (Tr. v. 22, p. 2114.) In rebuttal testimony, PG&E

witness Lytton indicates that PG&E's Account 903 "expense estimates include the amounts necessary to provide basic customer services to its CIA customers in 1999." (Exhibit 27, p. 8-17.) We are interested in knowing if PG&E's estimates are limited to the necessary amounts. Lytton offers little clarification on cross-examination: "What I can say is the 39 million encompasses what is required to fund the account services department employees and the basic service functions they'll perform." (Tr. v. 22, p. 2116.)

Finally, we do not ignore the fact that the accounting change was implemented in 1997, after the Commission denied funding for the Quality Contacts Program in the 1996 GRC. (D.95-12-055, 63 CPUC2d 570, 597-99.) PG&E claims that any reference to the program is irrelevant because it no longer participates in the program. PG&E is only partially correct in this contention. In the 1996 GRC decision, the Commission did not grant a blanket approval for rate recovery of all activities conducted by the Account Services Department as long as those activities are not described as Quality Contacts Program activities. The Commission's concern dealt with the impermissible prospect of asking ratepayers to fund anti-competitive activities. Thus, whether PG&E now participates in something called the Quality Contacts Program may be irrelevant, but the nature of activities its asks ratepayers to fund remains as relevant as ever.

It is incumbent upon PG&E to demonstrate that all of the funding it seeks in Account 903 for Account Services on behalf of CIA customers is for basic services only. ORA and Enron raise a legitimate concern that PG&E may be repackaging and renaming services that were not allowed in rates in the 1996 GRC, and seeking rate recovery of the costs of such services in this GRC. However, bald assertion does not substitute for some analysius and evidence. It is not incumbent upon PG&E to prove the negative proposition that it does not engage in previously disallowed activities in addition to its sworn testimony that it does not. PG&E witness Lytton asserts that the activities performed now and into 1999 are not those that were discussed during the 1996 GRC as the Quality Contacts Program, and cites examples. This is sufficient evidence to shift the burden of producing evidence to the adverse parties. In the absence of such contravening evidence, we find that PG&E has sustained its burden of proof on this issue.

The other component of PG&E's proposed $27.3 million increase in Account 903 Account Services expenses is its proposal for $7.3 million in recognition of inefficiencies created by the elimination of DSM functions. In effect, PG&E seeks to transfer the costs of DSM programs no longer included in rates to CIA customers. This proposal is without merit and will be denied.

9.2.3.3.4 Supervision Costs

PG&E's request for Account 903 includes almost $28 million in forecast expenses for supervision, $15.9 million for the electric department and $11.7 million for the gas department. As it does in connection with Account 902, ORA recommends adjustments in Account 903 for supervision costs. ORA's recommendation is for reductions of $6.5 million for the electric department and $4.1 million for the gas department. It is based on the level of supervision costs booked to Account 901 for the years 1992 through 1995. Based on the historical relationships of supervisory costs and total costs in the account, ORA determined that supervision costs should not exceed 10% of the amount projected in Account 903 for "other costs." As we determined in connection with Account 902, ORA's proposed adjustment is reasonable and will be adopted.

9.2.3.3.5 Postage

Differences between PG&E and Weil with respect to postage costs have been resolved through testimony submitted at the update hearing. Based on the announced postage rate increase effective January 10, 1999, PG&E has shown that on a weighted basis, postage costs in Account 903 will increase by 2.51% relative to 1997 recorded costs. This results in an increase of $1.048 million. PG&E had requested a postage-related increase of approximately $1.5 million in Account 903, and that amount is reflected in PG&E's latest forecast as set forth in the comparison exhibit. Accordingly, the postage component of PG&E's forecast should be reduced by $467,000, $257,000 for the electric department and $210,000 for the gas department.

9.2.3.3.6 Office Hours

Since September 1997, PG&E has reduced the business hours of 71 of its business offices. Business hours for 30 more offices may be shortened by the end of the test year. The average reduction is two hours per day, although reductions for some offices are as much as five hours per day. PG&E initially included approximately $700,000 in savings in Account 903 to reflect the reduced hours. PG&E has increased its estimate of savings to $1.1 million.

TURN estimated that the $700,000 adjustment proposed by PG&E is equivalent to $20 per hour of business office closure. TURN finds this to be inadequate. TURN notes that some offices have two employees, and contends that the fully loaded salary savings should exceed $20 per hour. TURN also assumes that PG&E will reduce hours at half of the additional 30 offices. TURN recommends an adjustment of $1.68 million in place of PG&E's adjustment. TURN recommends that PG&E's Account 903 forecast be reduced by an additional $980,000 based on PG&E's initially-proposed adjustment of $700,000. TURN considers PG&E's $1.1 million adjustment inadequate as well.

PG&E contends that the reduction of office hours does not always result in direct cost savings, and that efficiencies are also gained by the ability to redeploy employees to other areas. We see the logic of PG&E's position. However, we conclude that ratepayers are better off if the offices remain open the additional two hours. Rather than a reduction of expense associated with shortening office hours, we direct PG&E to keep the offices open and restore $1.68 million to PG&E's authorized expense in Account 903.

9.2.3.4 Account 904 (Uncollectibles)

PG&E has proposed using the 1996 recorded uncollectible rate of 0.370% of its billed revenues. Weil points out that the recorded uncollectible rate for 1997 was 0.267%. Weil proposes that the Commission adopt either the 1997 recorded factor or, as a secondary recommendation, the average factor for the 1992 through 1997 period of 0.337%. In its opening brief, PG&E acknowledges the variability of the uncollectible rate and accepts Weil's alternate recommendation of using the six-year average rate.

The recorded uncollectible factor for 1997 reflects PG&E's credit and collections activities, and PG&E acknowledges that these activities can be sustained. Thus, Weil's recommendation is reasonable and will be adopted.

9.2.3.5 Account 905 (Miscellaneous Customer Accounts)

Account 905 includes IT and electric industry restructuring costs. With the removal of restructuring costs, as determined in Section 12.1, PG&E's forecast of $18.5 million is reduced to $10.2 million for IT projects. The difference between PG&E's and ORA's estimates results from ORA's recommendation to disallow the Middleware and IT upgrade projects. These projects are discussed in Section 9.6. The difference between PG&E's forecast and Enron's forecast of $11.5 million results from Enron's use of a five-year average. We are not persuaded that averaging yields a more accurate forecast for this account.

Consistent with our determinations in Sections 9.6 and 12.1, the adopted forecast for Account 905 is zero.

9.2.4 Account 912 (Demonstration and Selling Expenses)

PG&E's proposed Account 912 expense estimates are $0.8 million for the gas department and $4.4 million for the electric department, or a total of $5.2 million. PG&E states that these amounts fund its uneconomic distribution bypass deferral and distribution business attraction and retention activities. Efforts to avoid bypass include opposition to municipalization of PG&E's distribution system. The tools used by PG&E to fight bypass include new rate schedules, market surveillance, and acquiring, maintaining, and analyzing customer information. ORA, Enron, and Weil oppose ratepayer funding for these activities.

PG&E contends that ratepayers benefit from deferral of distribution bypass and retention of customers on the distribution system. PG&E states that the purpose of its uneconomic distribution bypass deferral activities is to protect distribution ratepayers from the negative financial impacts of such bypass. PG&E states that its attraction and retention activities complement its efforts to defer uneconomic distribution bypass in that they are intended to also result in the retention of distribution contribution to margin (CTM), enhance distribution asset utilization, and potentially provide for early transition cost amortization.

Discussion

In deciding whether captive utility distribution ratepayers should provide funding for PG&E's marketing efforts to defer bypass, and attract and retain business, we first look to the Commission's decision in PG&E's test year 1996 GRC. There, the Commission determined that captive ratepayers should not be required to fund utility marketing activities in competitive markets, because doing so would be anti-competitive. (D.95-12-055, 63 CPUC2d 570, 599.) Marketing activities that provide no benefits to the general body of ratepayers should not be funded by them. (*Id.*) The Commission also determined that load retention activities "may provide some benefits for ratepayers to the extent they forestall uneconomic bypass," but provided that it was incumbent upon PG&E to demonstrate that it requires funding for these activities. (*Id.*)

We also look to our decision in PG&E's 1997 Rate Design Window (RDW) proceeding. There, the Commission acknowledged that ratepayers may benefit from customer retention:

> "To the extent that PG&E retains distribution customers on its system, the costs of PG&E's distribution system (which are relatively fixed, at least in the short term) can be allocated over a larger group of customers. This keeps the distribution component of each customer's rate lower than it otherwise would be, thus increasing the amount of headroom under the rate freeze available for CTC recovery." (D. 97-09-047, mimeo., p. 40.)

The Commission also acknowledged that ratepayers may benefit from providing PG&E the ability to address uneconomic bypass:

> "If we sanction restraints on PG&E's ability to compete and if a customer is allowed to uneconomically bypass to an alternate [transmission and distribution] service provider, all of PG&E's remaining ratepayers would be worse off than if Schedules E-TD and E-TDI were adopted and judiciously utilized." (*Id.*, p. 45.)

From these two decisions, it is clear that under certain conditions, the Commission may approve reasonable efforts to defer uneconomic distribution bypass and retain distribution customers. Moreover, to the extent that a rate option intended to achieve these deferral and retention objectives is appropriate, it is reasonable to allow general rate recovery of expenses associated with the administration of such rate option. However, before doing so, the Commission must be satisfied that ratepayers clearly benefit from the activities to be funded.

A demonstration of short-term ratepayer benefit may be sufficient to justify ratepayer funding of retention and bypass deferral expenditures. If ratepayers enjoy short-term benefits from deferring uneconomic bypass, we intend to secure those benefits for them. However, we have not decided whether expanding the scope of distribution competition is appropriate, and if it is, how captive customers are to retain the benefits of an integrated system. We are concerned with preserving the long-term benefits of an integrated distribution system for ratepayers and the general public, while accommodating the special needs of specific customers. Our staff is currently investigating the role that competition may play in this area. While that study is pending we are reluctant to conclude that PG&E requires additional ratepayer funding of anti-bypass efforts of the type proposed here. We do not intend to forego ratepayer benefits in the form of CTM, early transition cost recovery, and better asset utilization. But we are not prepared to acquire them with measures that may damage beneficial competition in the long run.

Finally, even to the extent that bypass deferral and business retention may be appropriate, justification for funding of activities to retain customers should be accompanied by a demonstration that retention of specific distribution loads will not burden the general body of ratepayers with the requirement of unnecessary new capital investment, or inappropriate subsidies of specific customers.

We evaluate PG&E’s showing with these precepts in mind. To demonstrate ratepayer benefit for its proposed Account 912 spending, PG&E

contends that for the test year, ratepayers could realize as much as $51 million in CTM if it spends $5.2 million on attraction and retention activities.[40] PG&E asserts that ratepayer benefits of distribution attraction and retention activities have averaged seven times the costs of those activities in past years. We find several serious flaws in PG&E's analysis. As Weil has demonstrated, it considers the utility rather than the ratepayer perspective, considers short-term costs and benefits, is not limited to distribution benefits and costs, and does not account for the possibility that assets may be sold to irrigation districts or other entities. By including generation benefits, PG&E in effect proposes that distribution ratepayers provide funding for activities that benefit generation.

ORA, Weil, and Enron have cast substantial doubt on PG&E's showing in support of its spending in Account 912. Accordingly, we deny PG&E's request. PG&E's proposal fails on two grounds. First, PG&E's CTM analysis is flawed, and PG&E has thus failed to demonstrate clear ratepayer benefits for these expenditures. Second, even though D.95-12-055 provided that captive ratepayer funding of anti-competitive activities is inappropriate, PG&E has not shown that its proposal is free of such effects.

9.3 Capital

9.3.1 Common Plant

Common plant includes communications equipment, structures and improvements, computers and software, motor vehicles, tools, and furniture. As shown in the following table, which is based on the comparison exhibit for PG&E

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[40] PG&E's inclusion of CTM analyses for the first time in its rebuttal testimony represents another example of PG&E's withholding of part its showing until filing rebuttal testimony.

and ORA and on Enron's opening brief for Enron, these parties' forecasts of common plant net additions for 1997 through 1999 differ substantially:

Recommended Net Common Plant Additions
(in millions)

Year	PG&E	ORA	Enron
1997	$ 92.8	$ 92.9	$ 30.9
1998	$279.0	$147.5	$ 31.7
1999	$171.1	$ 82.0	$ 32.7
Total	$542.9	$322.4	$ 95.3

Roughly half of PG&E's common plant net additions forecast for the period 1997-1999 is related to CIS and IT additions. The same is true for ORA's forecast. CIS and IT forecasting issues are addressed in Sections 9.5 and 9.6, respectively. This section addresses non-CIS / IT common plant net additions.

As with the distribution capital additions forecasts, PG&E developed project-specific information for projects over $1 million, and estimated spending on projects under $1 million on an aggregate basis by MWC. Most of PG&E's estimated common plant spending is for projects under $1 million. PG&E asserts that its forecasting methodology is essentially a business plan that reflects its collective judgment of common plant requirements in the test period.

ORA accepts PG&E's proposed non-CIS / IT investments for computer software, communications equipment, data handling, and office equipment for 1997 through 1999. ORA also accepts PG&E's recorded 1997 figures for transportation equipment, structures and improvements, and the "Other" category of common plant additions. Thus, for non-CIS / IT investments, ORA only takes issue with PG&E's estimates for these three categories, and only for 1998 and 1999. ORA proposes using the 1997 recorded figures as the estimates for 1998 and 1999 net common plant additions. Compared to PG&E's estimates for the three-year period, ORA's approach results in estimated net additions that are $106.2 million lower for non-CIS / IT net additions ($37.7 million for transportation equipment, $58.3 million for structures, and $10.2 million for Other additions.)

For transportation equipment, ORA contends that its proposal to use the 1997 recorded investment of $23.7 million is reasonable because it compares favorably with a six-year average of $25.1 million. ORA prefers the 1997 figure over the historical average because it assertedly includes efficiencies associated with IT projects that might not be reflected in the average. ORA criticizes PG&E's 1998 and 1999 forecasts of roughly twice the 1997 recorded spending because this level of spending assertedly has no relationship to the historical average for vehicle replacements. ORA also contends that vehicle replacements should be decreasing due to IT innovations. ORA recommends using 1997 data rather than an historical average for structures and improvements because earlier data includes generation plant related costs. ORA believes that the 1997 recorded level of spending should provide a reasonable estimate of spending in 1998 and 1999 because additions attributable to earthquake safety, flood disasters, and efficiency improvements are nearly complete.

Enron bases its forecast of net plant additions on the average of five years of recorded data. Enron calculated that from 1992 through 1996, net plant additions including CIS expenditures averaged $39.4 million. Enron contends that with PG&E's reduced role in generation, procurement, and public purpose programs, PG&E's level of common plant additions should be decreasing, not increasing substantially.

Discussion

As shown in the comparison exhibit, PG&E is proposing net common plant additions for transportation equipment, structures, and the "Other" category that total more than $280 million for the 1997-1999 period. For these three categories alone, the $93 million yearly average level of additions is more than double the 1992 through 1996 average level of net common plant additions, including CIS, calculated by Enron. Apart from a general description of its forecasting approach and a demonstration that historical net additions were affected by large retirements in 1993 and 1995, PG&E provides little explanation for increases of this magnitude. In view of this, as well as the incentives for capital spending that faced PG&E during the development of its GRC filing, we find PG&E's requested level of additions to be both excessive and unjustified.

While PG&E has not justified its proposed common plant spending level, we also find significant fault with ORA's forecast of non-CIS/IT additions for 1998 and 1999. The level of net common plant additions varies significantly from year to year. For example, PG&E spent $23.7 million on transportation equipment in 1997, but it spent $34.1 million in 1995 and $63 million in 1996. In general, the use of a single year's data without consideration of spending patterns over time is less reliable than an average of several years. Thus, we do not accept the contention that 1997 recorded spending on vehicles, which ORA did not adjust for inflation, is more reliable because it incorporates the effect of IT investments. Similarly, we are not persuaded by ORA's contention that averaging is inappropriate because additions attributable to earthquake safety, flood disasters, and efficiency improvements are nearly complete.

Finally, even though averaging is appropriate for forecasting common plant additions, we find fault with Enron's averaging approach. Enron only used data from 1992 through 1996. We are persuaded that it is reasonable to include 1997 data in the average calculation, although we note that this is not a major deficiency. More importantly, PG&E recorded unusually large retirements in 1993 and 1995, yet Enron included these extraordinary accounting entries in calculating its five-year average. Enron's failure to make appropriate adjustments for these retirements results in a substantial and unjustified understatement of historical net additions.

In its rebuttal testimony, PG&E presented a seven-year average of common plant net additions that incorporates methodological corrections that PG&E believes are required if averaging is used to determine an appropriate test year plant balance. The corrections include escalation of data from as early as 1991 to 1997 dollars, exclusion of Diablo Canyon common plant, and removal of extraordinary additions, retirements, and accounting adjustments. We accept these adjusted, seven-year average calculations as the most reliable basis for forecasting 1998 and 1999 common plant net additions for fleet (autos), buildings and structures, and "Other" additions. Although PG&E opposes the use of averaging that includes the effects of the economic downturn of the early and mid 1990's, we find little merit in this position. As Enron properly observes, PG&E has not established the existence of a strong relationship between common plant expenditures and the state of the economy.

The following table shows PG&E's and ORA's recommendations for fleet, buildings and structures, and "Other" additions as set forth in the comparison exhibit. It also shows our adopted estimates of common plant additions for these categories. For 1998 and 1999, the adopted estimates are based on PG&E's seven-year average calculations as set forth in Table 5-4 of its rebuttal testimony. For other, non-CIS / IT common plant forecasts which ORA and PG&E agree upon, we adopt PG&E's forecasts as set forth in the comparison exhibit.

Adopted Net Common Plant Additions
Autos, Structures, Other
(thousands of dollars)

		PG&E	ORA	Adopted
1997	Autos	23,733	23,733	23,733
	Structures	26,749	26,749	26,749
	Other	7,540	7,540	7,540
1998	Autos	41,856	23,733	30,258
	Structures	54,836	26,749	28,946
	Other	12,580	7,540	6,696
1999	Autos	43,260	23,733	31,106
	Structures	56,923	26,749	29,243
	Other	12,746	7,540	6,883

9.3.2 Materials & Supplies

PG&E maintains stores of materials and supplies (M&S) at various service centers and storage facilities throughout its system. Although its inventory management policy remains unchanged, PG&E forecast an increase in M&S inventories in 1997 from the 1996 recorded level to support an increasing demand for materials in electric and gas distribution. PG&E expected its inventory level to remain relatively flat in 1998 and 1999. According to PG&E, M&S inventory balances are to a large extent determined by the planned level of construction. PG&E states that this explains why the M&S inventory balance increased in 1997.

For 1999, PG&E forecasts electric distribution M&S inventory of $64.4 million and gas distribution M&S inventory of $9.2 million. ORA's forecasts are $36.9 million and $6.0 million, respectively. The total M&S dollars at issue in this proceeding are $27.6 million for the electric distribution UCC, $3.2 million for the gas distribution UCC, and $30.8 million in total.

ORA's M&S recommendations are based on recorded spending, and reflect its position that implementation of various IT projects should reduce required inventory levels. ORA also believes there is a declining trend in M&S levels that should be reflected in the test year forecasts.

PG&E has shown that there is not a persistent declining trend of M&S levels as ORA asserts. Also, we find that ORA's position regarding the potential M&S savings of IT projects lacks adequate support. ORA's analysis of recorded data reflected a spreadsheet error by PG&E that was subsequently corrected by PG&E but not reflected in ORA's calculations. Since M&S inventory balances are related to the planned level of construction, and capital spending has increased since the early 1990's, PG&E's proposed M&S levels for the electric and gas distribution UCCs are fully justified, and are therefore adopted.

9.3.3 Customer Advances

TURN recommends adjustments to PG&E's customer advances calculation to reflect the effect of new tariff rules governing line extensions. PG&E witness Flavell acknowledges that PG&E has experienced a steady decline in both gas and electric customer advance balances. PG&E agrees with the basic logic and methodology developed by TURN, and proposes that the adjustments be applied to May 1998 data, the most recent recorded data available. The electric customer advance balance was $66.4 million, and the gas customer advance balance was $12.4 million. Accordingly, PG&E recommends adoption of its 1999 test year weighted average customer advance balances of $69.8 million for the electric department, and $13.5 million for the gas department. This undisputed proposal is reasonable and is therefore adopted.

9.3.4 Depreciation

9.3.4.1 Introduction and Preliminary Matters

Depreciation expense is a function of the level of plant and of the depreciation parameters (net salvage value and service life) that are applied to gross salvage amount received less the cost of removing the asset. It can either be positive or negative. For an asset with a net salvage value of 10%, 90% of the original investment is recovered through depreciation. For an asset with a negative net salvage value of -10%, 110% of the original investment is recovered through depreciation. Average service life (ASL) is determined through a life analysis. A longer ASL results in a longer remaining life and, therefore, a lower annual depreciation expense.

To develop its proposal for depreciation in this GRC, PG&E prepared a new depreciation study and applied the results to its forecast of 1999 plant balances. PG&E's proposed depreciation rates would produce $1.045 billion of annual depreciation and amortization expense excluding the amounts related to electric production and Line 401. This is an increase of $282 million, or 37%.

PG&E's depreciation study, the net salvage value and service life depreciation parameters developed therein, and alternative recommendations of other parties are at issue. ORA, AECA, and TURN presented testimony addressing PG&E's depreciation forecast. ORA disputes PG&E's forecasts for gas distribution services (Account 380), the account for which PG&E's depreciation proposal has the largest impact, and for capitalized software and hardware associated with PG&E's CIS projects (Account 391). ORA disputes the negative net salvage value proposed by PG&E for the former, and the service lives proposed by PG&E for the latter. ORA also proposes that we institute an investigation into appropriate net salvage value for gas distribution assets.

AECA raised concerns about PG&E's accounting treatment of asset removal expenses. Because PG&E is estimating substantial increases in removal costs, AECA assumes that the costs were previously recovered elsewhere, most likely in transmission and distribution maintenance expenses. AECA recommends that transmission and distribution expenses be credited by $16 million and $36 million, respectively, to offset this asserted accounting shift.

TURN conducted a comprehensive analysis of PG&E's depreciation showing and presented its own detailed proposal for depreciation and amortization. TURN engaged the services of Jacob Pous, principal of Diversified Utility Consultants, Inc., to review and critique PG&E's showing on depreciation issues. Based on its depreciation analysis, TURN concluded that the depreciation rates now in effect are excessive for many accounts. With respect to net salvage value, TURN recommends adjustments to 17 electric plant accounts, six gas accounts, and two common plant accounts. With respect to ASL, TURN recommends adjustments to eight electric plant accounts, two gas accounts, and three common plant accounts. TURN recommends adoption of depreciation parameters that yield an annual depreciation and amortization accrual of $611 million. UC / CSU, and DGS support TURN's analysis and recommendations for depreciation. In its opening brief, ORA states it is "impressed by the amount of time and effort that went into TURN's review of PG&E's depreciation study and proposed studies." (ORA Opening Brief, p. 263.) ORA is persuaded by TURN's testimony and analysis, and is generally supportive of TURN's recommendations. In addition, based on its review of TURN's showing, ORA recommends that if the Commission does not adopt TURN's recommendations, it should at a minimum reject PG&E's showing and maintain the status quo. UC / CSU concurs with ORA's secondary recommendation.

Discussion

PG&E's proposed depreciation parameters, and particularly its proposed net salvage value factors, result in large revenue requirement impacts. As noted earlier, PG&E's depreciation proposal in this GRC results in a $282 million, or 37%, increase in depreciation and amortization expense above the $763 million level that results from applying currently authorized depreciation parameters. Using the same basis for comparison, TURN's proposed depreciation parameters result in an annual expense reduction of nearly $152 million, or 20% from the current level. Thus, TURN proposes a depreciation and amortization expense level which is $433 million less than PG&E's proposed expense.

A large portion of the difference between PG&E and TURN is attributable to their net salvage value proposals. Compared to PG&E's requests for net salvage value alone, TURN's net salvage value proposals result in a $316 million reduction of the annual depreciation expense. Compared to PG&E's requests for service lives alone, TURN's proposals result in a $140 million reduction. (Due to their interactive effects, the total stand-alone impacts of proposals for service life and net salvage are greater than their combined impact.) Through its proposed net salvage values factors, PG&E in effect forecasts far higher costs than previously estimated for the removal of assets at the end of their service lives. PG&E's depreciation proposal in this GRC reflects more than $13 billion for negative net salvage value over the life of the investments. This represents an increase of $7.8 billion, or 150%, over the value associated with current depreciation parameters.

It is useful to look at PG&E's proposal for Account 380 (gas distribution services). For this account, PG&E proposes applying a negative net salvage value of -350%. Currently, pursuant to the depreciation study adopted in the test year 1996 GRC, PG&E uses a negative net salvage value of -120%. TURN proposes a negative net salvage value of -75%. For Account 380 alone, PG&E is asking for reimbursement of $5.1 billion in depreciation expense over the life of the investment for the anticipated negative net salvage value. This amount is $3.4 billion more than the existing level, and is over and above recovery of the $1.47 billion plant balance.

There are important policy reasons for rejecting revenue requirement increases that are justified solely on the basis of new depreciation parameters. As TURN observes, depreciation does not affect PG&E's ability to provide safe and reliable service. Even if the proposed or current rates of depreciation are reduced, shareholders will still recover their investments in plant over time. At the same time, we have determined that it is necessary to set the authorized revenue requirement in this GRC at a level that is consistent with the provision of adequate utility service by PG&E. Thus, to carry out our policy position on revenue requirement increases, we will make changes in authorized depreciation parameters when presented with compelling reasons for doing so. For example, if a net salvage factor for a given account underestimates asset removal costs, that could have the effect of providing a short-term benefit to current ratepayers, through a lower revenue requirement in the short term, but at the expense of future ratepayers who would be asked to make up the shortfall. If it is shown through clear and convincing evidence that failure to revise the depreciation parameters for a given account has the effect of inappropriately shifting costs to future ratepayers, we would adopt an appropriate revision in order to prevent the occurrence of that effect. We would do the same if a current depreciation factor overcharges current ratepayers for the benefit of future ratepayers. We also bear in mind that ultimately, the determination of depreciation parameters is a matter of judgment, just as with any other forecast in this GRC. Finally, as TURN witness Pous states, depreciation is a very subjective area.

ORA has not shown that an investigation into net salvage value for Account 380 is warranted. Of course, in any proceeding in which PG&E places its depreciation expense at issue, PG&E will retain the burden of proof as to the reasonableness of its proposal, including any depreciation study it may present in support of its proposal. Also, AECA has not shown that PG&E's proposed net salvage value factors justify offsetting credits to O&M expense accounts. AECA's proposals are therefore rejected. In the following sections we address PG&E's depreciation study and resulting recommendations, as well as TURN's depreciation showing. Our consideration of ORA's proposals for the Account 380 net salvage values is subsumed within our discussion of PG&E's and TURN's showings. We address ORA's proposals for CIS plant service lives and TURN's proposal for amortization true-up in subsequent sections.

9.3.4.2 Depreciation Analyses

PG&E witness Kalich presented an updated depreciation study for 1999 which shows the results of PG&E's mortality and net salvage analysis for plant and equipment. Kalich suggests that the study involved a two-step process. First, historical data by asset class is used to estimate the average service life, curve type, and net salvage ratio for each asset class.[41] The second step involves the analysis of the indicators derived in step one for each asset class. Kalich states that step two is accomplished by drawing upon the knowledge and experience of persons familiar with depreciation characteristics to determine

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41 Curve types are the time patterns which describe the probability of retirement of a fraction of the initial group in each time period.

whether the indicators provide an accurate forecast of the mortality and salvage behavior of the equipment in that asset class. Kalich further states that if the conditions affecting the service life of assets in the future will be different, expert judgment is used to derive the future value of these variables.

TURN identifies numerous asserted problems with PG&E's depreciation study. These include, but are not limited to, the following:

> Despite PG&E's description of the two-step process of (1) historical analysis and (2) review by those who are knowledgeable of and experienced with the performance of the assets, PG&E's depreciation study relies almost exclusively on a mechanical incorporation of historical data by a depreciation expert. There was no significant review by knowledgeable and experienced field personnel. TURN notes that in the last GRC, PG&E itself found fault with blind reliance on simple historical averages.
>
> For Account 380, PG&E relied on a very small sample of retirements ($6.5 million in retirements compared to a plant balance of $1.5 billion) to develop its proposed net salvage value without performing statistical tests or other analysis that would support the use of the sample. As an example of questionable data, for 1998 PG&E recorded $2.6 million for costs of removal and $67,000 in retirements.
>
> Notwithstanding its recognition of the need for consistency, PG&E treated historical salvage value and mortality data inconsistently. Thus, for electric plant Account 353, PG&E rejected Simulated Plant Record (SPR) analysis results as unrealistic because it produced an ASL of 100 years, or 2.5 times the currently authorized 42 years. Yet, as noted elsewhere, for Account 380 PG&E accepted the results of an historical analysis that yields a negative net salvage value that is nearly triple the currently authorized value and is more than double the highest level recorded for utilities in an industry comparison sample.
>
> PG&E's analytical approach gives too much weight to the existence of existing depreciation parameters. In effect PG&E takes the position that existing parameters are reasonable unless proven otherwise.

PG&E made inadequate and inappropriate use of industry comparisons. Industry comparisons for Account 380 considered by PG&E show net salvage rates that ranged from -5% to -160%, averaged -64.2%, and had median and modal values of -50%. Yet, as noted above, PG&E proposes to change its current factor from -120% to -350%. Moreover, the industry comparison sample used by PG&E was small, consisting of six comparison utilities for this account, even though PG&E had available a much broader sample. While the broader sample of data includes utilities operating in geographically diverse areas, TURN does not believe that geographical differences translate into discernible net salvage differences. Further, TURN suggests that PG&E's attempt to restrict its sample to geographically similar utilities is flawed. For example, TURN questions whether Hawaiian Electric Company operates in an economic and regulatory environment similar to PG&E’s.

Historical data on retirement costs reflect relatively few retirements compared to the future level. The greater level of retirements should result in economies of scale that reduce the unit costs of removal of plant, yet no such economies are reflected in PG&E’s analysis.

When an asset is retired and is replaced, and PG&E receives reimbursement for more than the book value, (for example, when a car damages a pole), PG&E reports reimbursed amounts as a reduction in the cost of the replacement rather than as gross salvage. TURN contends that this is inconsistent with the USOA definition of gross salvage, and inflates depreciation cost. PG&E does reflect amounts received as gross salvage when no replacement activity occurs. TURN contends that the full reimbursement amount should be assigned to gross salvage.

PG&E accounts for some replacement costs as costs of removal rather than as cost of new plant. TURN contends that this is inconsistent with the USOA and defies common sense.

PG&E’s SPR analysis, a method of semi-actuarial analysis, was assertedly flawed because PG&E, for the first time, did not use the Retirement Experience Index (REI) criterion for analyzing the goodness of fit of the SPR analysis results. The REI measures the robustness of the sample results. In the 1996 GRC, PG&E’s depreciation study described the mortality analysis used as based on a conformance index and the REI.

> PG&E described the REI as an indicator of whether there is sufficient retirement experience to provide meaningful results.
>
> PG&E's depreciation study presented graphs of ASL data showing the proportion surviving as a function of age. TURN asserts that these graphs serve no useful function in connection with semi-actuarial analysis, and in any event were not used by PG&E.
>
> PG&E compared bands of data that ended in 1994 and 1995 as well as bands of data that ended in 1996. TURN contends that ignoring the most current data reduces the information available, is inconsistent with the company's practice in the 1996 depreciation study, and is inconsistent with its approach for net salvage value in this study.
>
> PG&E limited its experience band analysis to bands of 20 and 40 years. In the experience of TURN witness Pous, it is typical for utilities to perform three to five different experience bands. Pous performed four experience bands for his analysis.

Discussion

TURN has raised important questions about the assumptions and methods underlying PG&E's study that are not adequately addressed by PG&E. We accept TURN's analysis as valid and reliable, although we do not accept each and every point advanced by TURN. In particular, we are not persuaded that PG&E's accounting practices with respect to retirements and replacements are in contravention of the USOA. As explained below, PG&E offers inadequate support for its depreciation study or the large revenue requirement increase that would result from its adoption.

PG&E relies on a mechanistic transformation of historical recorded accounting data into proposed depreciation parameters, a transformation which was not effectively tempered by the judgment of field personnel, engineers, and others who are in a position to make such judgments. PG&E's failure to duly consider the knowledge and experience of its own personnel who are familiar with the performance of its utility assets is particularly problematic for two reasons. First, historical accounting data alone may not disclose what is actually happening in the field. Second, PG&E's depreciation witness has only limited experience in energy utility operations, and is admittedly not familiar with the assets in the field. PG&E essentially assumes that history will repeat itself without analyzing the reasonableness of that assumption.

PG&E attempts to downplay the importance of TURN's reliance on industry comparisons by pointing to geographic location, company size, account size, account composition, specific accounting policies and practices, and local regulatory and environmental factors. We find this attempt fails. PG&E itself purported to use industry comparisons in its analysis, although its samples of comparison utilities were relatively small. TURN has shown that geographical differences among utilities do not necessarily translate into net salvage value differences.

Significantly, PG&E does not articulate and support a compelling rationale for determining that the cost of asset removal is much higher than it was thought to be just three years ago, but that is what its depreciation study implies. We are not prepared to add billions of dollars to the existing forecast of net salvage value on the basis of PG&E's showing. Historical data developed by PG&E may indeed suggest that there is an increasing trend in negative net salvage value for Account 380, but we require more justification before adopting PG&E's proposed increase in negative net salvage value, from -120% to -350%. PG&E's explanation that the trend reflects the ongoing GPRP is at best incomplete and unpersuasive. We fail to understand why, half-way into that program, negative net salvage value might be expected to jump as PG&E's historical analysis suggests.

TURN's showing on depreciation represents a major contribution to our analysis of PG&E's proposed depreciation allowance. TURN has cast substantial doubt on the reliability and accuracy of PG&E's 1999 depreciation study. We conclude that PG&E's 1999 depreciation study lacks adequate substantiation, and cannot be used as the basis for developing the authorized depreciation expense in this GRC.

At the same time, we are not persuaded that it is reasonable to reduce PG&E's revenue requirements by more than $150 million on the basis of TURN's showing. We are concerned that TURN's depreciation analysis may be subject to one of the problems that undermine PG&E's study. In particular, even though TURN's depreciation witness has extensive experience as a depreciation expert, TURN has not demonstrated that its recommendations incorporate the knowledge and experience of the PG&E personnel who are most familiar with the behavior of PG&E's utility assets.

Based on the foregoing analysis and conclusion that neither PG&E's nor TURN's depreciation showing provides sufficient basis for changing depreciation parameters. In view of our overarching policy position on the need to balance revenue requirements and to better understand PG&E's maintenance practices and new capital investment programs, we find that ORA's secondary recommendation to continue the use of depreciation parameters adopted in the previous GRC is necessary and appropriate, both for net salvage value and for service lives, with the exception of CIS-related plant, which is addressed in the following section. We may revisit this issue in the 2002 GRC we have directed to be filed elsewhere in this order.

9.3.4.3 CIS Plant Service Life

PG&E recommends a five-year service life for hardware and a seven-year life for software. PG&E contends that its recommendations for the depreciable lives of all data processing hardware and software, including CIS, reflect the rapidly changing technologies in these accounts. PG&E contends that its depreciation estimate for hardware is consistent with the Commission's decision in PG&E's last rate case, the five-year life approved for Edison and SoCalGas, IRS guidelines, a Florida Power & Light decision (Fla. Pub. Serv. Com. Order No. PSC-96-0841-FOF-EI (July 1, 1996)), and Hitachi Data Systems' assessment that its mainframes have useful lives of about five years.

ORA recommends adoption of a 20-year service life for CIS-related plant. ORA contends that this is consistent with an industry survey (the 1998 Chartwell CIS Report) indicating that similar CIS systems are expected to have a life of 15 to 20 years. ORA acknowledges that a position paper by the American Institute of Certified Public Accountants stated that software often has had a relatively short useful life. However, ORA also observes that a 20-year life is consistent with D.97-07-054, in which the Commission adopted a 20-year service life for SoCalGas' new CIS system. ORA further points to PG&E's own expectation regarding the useful life of the CIS as set forth in the CIS Technical Evaluation Report. Significantly, the report stated that "[b]ecause the new CIS system will be expensive and difficult to replace, it must have an effective lifespan of at least 15 years." ORA points out that PG&E's depreciation witness did not consult anyone on the CIS technical evaluation team. Finally, ORA observes that while the witness testified that just because an item has an effective lifespan of 15 years that doesn't mean that it should be depreciated at 15 years, he also testified that a key element of determining annual depreciation expense is accurately estimating the probable life of an asset; i.e., the period over which the asset will provide benefits or will have economic value.

PG&E objects to the 20-year life for CIS plant in part because the accounts in which this asset is booked include numerous other assets. In response to this concern, ORA recommends the use of subaccounts. ORA contends that the use of subaccounts is consistent with the approach taken by the Commission with respect to SoCalGas' CIS system.

Discussion

We find that ORA's showing with respect to CIS plant service lives is more persuasive than PG&E's showing. While PG&E asserts that CIS plant is associated with rapidly changing technology, PG&E's depreciation witness did not rely on this assertion, nor did he consult with PG&E's CIS technical evaluation team. While D.97-07-054 adopts a settlement agreement between ORA and SoCalGas, and the Commission's decision is without precedential value, the fact remains that SoCalGas' CIS team projected savings over a 20-year period.

PG&E's reliance on the Florida Public Service Commission decision is premature, since the decision was preliminary, subject to true-up, and the Florida commission expressly stated that its order did not imply agreement with the company's proposals. (Fla. Pub. Serv. Com. Order No. PSC-96-0841-FOF-EI (July 1, 1996).) We give little weight to PG&E's reliance on assessments by Hitachi corporation. This assessment consists solely of two electronic mail postings by Hitachi representatives. Both are dated the evening of September 28, 1998, one day before ORA's CIS witness was cross-examined on this subject. We have no basis for verifying the credibility of the assertions of the Hitachi representatives.

Finally, the Chartwell report relied upon by ORA is based on independent research. It generally supports ORA's position, as does the in-house CIS Technical Evaluation Report prepared for CIS managers and officer sponsors in preparation for vendor selection in 1996.

In the face of extensive evidence that ASLs of seven years for computer software and five years for office machines / computer equipment are unjustifiably short, we reject PG&E's proposed service lives for CIS plant. On the other hand, 20 years is unjustifiably long. We note that ORA itself indicates that two of the reports it relies upon suggest that service lives of 15 to 20 years are supported. We find that a service life of 15 years for CIS plant is reasonable, and we therefore adopt it.

9.3.4.4 Amortization of True-Up

PG&E's depreciation proposal includes approximately $16.1 million in annual expense for a one-time true-up that was approved in D.95-12-055 as a means to amortize the impact of one-time accounting method changes adopted in that case. The changes were to be amortized over periods of three or six years. PG&E is not proposing any changes in those amortization schedules. The three-year amortization schedules expire prior to 1999, and are not included in PG&E's showing in the GRC. PG&E notes that the six-year amortization schedules adopted in D.95-12-055 will continue through 2001.

TURN contends that adoption of the true-up in the last GRC is not sufficient justification for continuation of the expense in this GRC. TURN believes that the dynamic nature of depreciation parameters is reason to review the true-up authorization in this GRC. TURN concludes from its analysis that the true-up should change from a positive to a negative value, but is unable to quantify the impact. TURN thus recommends that a zero level of true-up be adopted at this time.

We conclude that the current amortization schedule should be continued in effect, as it is consistent with our determination to continue use of depreciation parameters adopted in the previous GRC. TURN's proposed zero true-up is therefore denied.

9.3.5 Decommissioning

9.3.5.1 Diablo Canyon Decommissioning Trusts

9.3.5.1.1 Funding Policy

Decommissioning of Diablo Canyon plant is currently scheduled to begin as early as 2015. PG&E estimates the cost of decommissioning at $511 million for Diablo Canyon Unit 1 and $724 million for Diablo Canyon Unit 2, or a total of $1.235 billion in 1997 dollars. These estimates include a 40% contingency factor. Decommissioning costs exclude nuclear fuel disposal costs but include the costs of disposing low-level radioactive wastes (LLRW).

The Diablo Canyon nuclear decommissioning trusts are a means of setting aside adequate funds for the eventual cost of decommissioning. At the end of 1997, the fund balances were $410 million for Diablo Canyon Unit 1 and $524 million for Diablo Canyon Unit 2, or a total of $934 million. Net of tax liability, the available balances totaled $876 million at the end of 1997.

PG&E proposes to continue funding the trusts at the $34.4 million per year rate that was approved in the last GRC. PG&E developed this recommendation by applying its proposed cost escalation rates, contingency factors, and trust fund rates of return to its estimated decommissioning cost. Edison and the Redwood Alliance support PG&E's recommendation for funding the trusts.

ORA witness Kinosian and FEA witness Smith oppose PG&E's proposal for decommissioning funding, recommending that no additional contributions to the trusts be authorized in this GRC. ORA and FEA accept PG&E's estimate of decommissioning costs, but dispute the trust fund rates of return, escalation factors, and contingency factors assumed by PG&E. FEA contends that the trusts are already fully funded based on reasonable assumptions. ORA contends that the funds already contain more than what is needed to pay for eventual decommissioning costs. Despite the asserted overcollection, ORA does not recommend the return of any funds to ratepayers at this time. Instead, ORA believes that excess funds can serve as an additional contingency factor.

Discussion

The policies we follow for funding nuclear decommissioning costs are well established. We are guided by Section 8322, which sets out legislative findings and declarations associated with the Nuclear Facility Decommissioning Act of 1985, and by Section 8325 of the Act. Section 8322(f) provides that the principal considerations in establishing a state policy respecting the economic aspects of decommissioning are the following:

> "(1) Assuring that the funds required for decommissioning are available at the time and in the amount required for protection of the public.
>
> "(2) Minimizing the cost to electric customers of an acceptable level of assurance.
>
> "(3) Structuring payments for decommissioning so that electric customers and investors are treated equitably over time so that customers are charged only for costs that are reasonably and prudently incurred."

Section 8322(f) indicates that we need to balance competing interests. We are charged with providing assurance that required decommissioning funds are fully available when needed, but the assurance to be provided is not absolute. It must be "acceptable," i.e., reasonable.[42] At the same time, we must seek to minimize ratepayer funding responsibility, and allocate that responsibility equitably over time consistent with Section 8325.

Section 8325(c) provides:

> (c) The commission shall authorize an electrical corporation to collect sufficient revenues in rates to make the maximum contributions to the fund established pursuant to Section 468A of the United States Internal Revenue Code and applicable regulations, that are deductible for federal and state income tax purposes, and to otherwise recover the revenue requirements associated with reasonable and prudent decommissioning costs of the nuclear facilities for purposes of making contributions into other funds established pursuant to subdivision (a).

This provision requires us to ascertain the maximum level of contributions deductible for tax purposes and to authorize them in rates.

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42 In D.83-04-013, issued before the enactment of the Nuclear Facility Decommissioning Act of 1985, we provided for a high level of assurance that decommissioning can be accomplished promptly and efficiently, and that such assurance is the single most important criterion for evaluating financing mechanisms. (11 CPUC2d 115, 119.) Assurance was ranked ahead of cost, equity, and flexibility. (*Id.*) However, this did not mean that the Commission would single-mindedly select the financing alternative with the greatest assurance. The Commission provided that the criteria of cost, equity, and flexibility would temper the selection. (*Id.*, 135.)

In PG&E's last GRC, we addressed our responsibilities for nuclear decommissioning funding policy with the following principles in mind:

> "We retain our concern that nuclear decommissioning funds be adequate to cover future decommissioning costs, consistent with the legislative policy enunciated in the Nuclear Power Plant Retirement Act of 1985. We are mindful, however, that today's forecasts of nuclear decommissioning costs occurring 10 to 20 years in the future are very speculative. Forecasts of economic activity and costs out that far into the future are always subject to substantial error. In the case of nuclear decommissioning costs, forecasts are likely to be even more speculative because of the nation's limited experience with such activity. Therefore, we would be fooling ourselves if we believed we could forecast those costs with any precision. Our goal is to have funds on hand that appear reasonably adequate. Moreover, in our efforts to protect future ratepayers from costs incurred by today's ratepayers we do not wish to impose costs on today's ratepayers which, if funding exceeds future costs, would represent a windfall to future ratepayers." (D.95-12-055, 63 CPUC2d 570, 612.)

We went on to state that:

> "In setting an annual nuclear decommissioning revenue requirement, our objective is to provide some insurance against a circumstance which would require significant rate increases in the future to retire plant that has served an earlier generation of users." (*Id.*, 613.)

The precepts that guided our consideration of nuclear decommissioning funding in the last GRC appear to be equally appropriate and applicable here. We find no basis for a change in our nuclear decommissioning funding policy. We also affirm the observation that forecasting nuclear decommissioning costs that will be incurred 15 years in the future is both imprecise and speculative. For all of these reasons, we concur with PG&E that we should continue a conservative approach to funding.

Taking a conservative approach does not mean that every single element of the forecast of funding needs should be slanted in favor of greater current ratepayer contributions to the decommissioning trusts. As the Commission clearly indicated in the last GRC, it is possible to be overly conservative in making current forecasting assumptions, and to thereby create the risk of an unjustified windfall for future ratepayers at the expense of today's ratepayers. As a matter of established policy, avoiding that outcome is part of the mix of considerations we take into account. Thus, the argument repeatedly put forth by PG&E, which in general form says that "Assumption A is superior to Assumption B because Assumption A is more conservative," fails in the absence of evidence that Assumption B is not reasonably conservative. On the other hand, to the extent that current ratepayers are benefitting from the ouput of the nuclear powerplants, it is more equitable that they make contributions toward the eventual decommissioning if that lessens the likelihood that future ratepayers -- who receive nothing from nuclear plant operation -- will be burdened with the costs of environmental remediation.

There appears to be little disagreement among the parties over the foregoing policy considerations. The issues involve differences over long-term forecasting assumptions, and the allocation of the risk of forecasting error. Although we ultimately reject ORA's and FEA's proposals, they do not necessarily represent departures from Commission policy simply because they would provide for no additional ratepayer contributions.

9.3.5.1.2 Updated and Corrected Data

PG&E's analysis of decommissioning funding reflects a forecast of the 1997 balances in the decommissioning trust funds. ORA's testimony reflects more recent recorded information, including higher balances in the funds. PG&E

acknowledges that incorporating the gains in the trusts through the end of 1997 into the funding analysis would lower the required funding level to $28.7 million annually. Nevertheless, PG&E proposes maintaining the current level of funding on the grounds that it is a more conservative approach.

PG&E's proposal to ignore updated trust fund balances is unjustified and is therefore rejected. Also, FEA notes that certain corrections to PG&E's forecast result in a reduction of $680,000. PG&E does not dispute the corrections. Accordingly, even if we adopt all other aspects of PG&E's forecasts as reasonable, it would be unreasonable to adopt an annual funding level of more than $28 million.

9.3.5.1.3 Assumed Return on Equities

PG&E assumes that the equity portion of the trust funds will earn 10.5% before taxes. As support for its position, PG&E contends that, on a 10-year rolling average basis, the annualized return for the U.S. equities market from 1920 to 1996 was 10.3%.

In PG&E's last general rate case, PG&E assumed that equity investments earned 11%. Accordingly, ORA has assumed earnings of 11.0% in this GRC. ORA finds support for this position by reference to the 50-year historic return on the Dow Jones Industrial Average of 12.5%. ORA notes that it does not actually base its estimate on this return, but instead uses it to show that the 11% return it proposes is conservative. ORA points out that the average return on the Standard and Poor's 500 Index has been greater than the return on the Dow Jones Industrial Average over the last 50 years. Finally, ORA notes that PG&E's use of averages of 10-year rolling averages systematically gives insufficient weight to the first nine years and the last nine years of the historic period reviewed.

Compared to the 50-year performance of equities as measured by the Dow Jones and Standard and Poor's indexes, an assumed return of 11% is conservative. PG&E has not shown why a rate of return that was considered conservative in the last GRC is no longer sufficiently conservative. ORA's assumption of 11% is fully consistent with our funding policy.

9.3.5.1.4 Assumed Fixed Income Returns

PG&E assumes that the return for the fixed income portion of the trust funds should be 4.89% after taxes. In contrast, ORA assumes that a rate of 5.25% should be used. PG&E contends that returns of as high as 5.25% are not available for investments that are acceptable for nuclear trusts over the long term. ORA argues that current yields on tax free investments could enable PG&E to realize after tax returns consistent with its higher assumption, but fails to document a long-term trend. PG&E has shown that its fixed income assumption is reasonable and should be applied to the analysis of funding requirements.

9.3.5.1.5 Taxation Assumptions

PG&E assumes that all capital gains and interest are fully taxed each year. Since capital gains are only taxed when the securities are sold, ORA contends that PG&E' assumption ignores the benefit of deferring taxes by holding securities for a term longer than one year. According to ORA, this causes PG&E to underestimate the future fund balances. ORA makes the assumption that half the capital gains on equities is taxed each year. ORA considers this to be a very conservative assumption. ORA's approach results in an increase in expected fund value of over $200 million by the year 2017.

In its opening brief, PG&E states that its "conservative assumption regarding taxation timing is the more reasonable," and that it "is the same method the Commission has used in past cases." (PG&E Opening Brief, p. 330.)

ORA points out that consideration of the impact of taxes, including the benefits of deferring taxes, is a fundamental part of financial analysis. The assumption that deferring recognition of capital gains by holding the appreciated asset longer will reduce taxes on capital gains is highly speculative, if not erroneous. We will retain the assumption used in PG&E's last GRC that capital gains will be fully taxed.

9.3.5.1.6 Conversion to Lower Risk Investments

PG&E assumes that equity holdings will be transferred to lower yielding bond investments beginning in the year 2010. The transfer of all funds to bonds is to be completed by 2015 when decommissioning is assumed to begin. ORA notes that this transfer of funds to investments with lower expected earnings was not assumed in PG&E's last GRC. Moreover, ORA contends that it underestimates the likely fund earnings, and is overly conservative. Even though it is anticipated that the funds will be expended on decommissioning beginning in 2016, most of the funds will remain in the trusts for a number of years. The final amounts will not be spent for an additional 20 years.

Even though PG&E's assumption was not used in prior analyses, it is prudent to move part of the portfolio to lower return and lower risk investment vehicles as the time approaches to begin expending funds, and to have completed that process at the time that funds are to be expended. PG&E's approach is appropriate in its timing assumptions.

9.3.5.1.7 Labor Cost Escalation

PG&E assumes labor escalation rates of 3.4% in 1998 and 1999 based on collective bargaining agreements, and 4.7% thereafter. PG&E states that its labor cost escalation includes anticipated escalation in employee benefits as well as wages.

ORA notes that PG&E's contract labor escalation rate is 3.4%, and that DRI has forecast an inflation rate of approximately 3%. ORA's contention that it is not reasonable to assume PG&E employees can look forward to salary increases well above the inflation rate every year for the next 20 years. ORA further notes that neither it nor PG&E has forecast any labor productivity improvements, which likely has the effect of overstating future labor costs.

Edison notes that the forecast for the Employment Cost Index (ECI) for the period 1998 through 2008 shows a higher growth rate than the growth rate for the Consumer Price Index (CPI) used by ORA. However, as shown in Exhibit 359, the ECI figures for total compensation for 2000 through 2008, while higher than the respective CPI figures, are closer to the CPI figures than the 4.7% rate assumed by PG&E. PG&E's labor escalation factor produces a conservative measure of funding needs that is appropriate considering the potential job-related risks and potential requirements for specialized workers at the time that decommissioning will commence. We cannot foresee the labor market conditions with any certainty, and therefore accept PG&E's assumption.

9.3.5.1.8 Waste Disposal Cost Escalation

PG&E's decommissioning cost study assumes that all radioactive wastes generated during the decommissioning process which meet the requirements of 10 CFR Part 61 Classes A, B, and C will be shipped for permanent disposal at the U.S. Ecology Ward Valley site. Federal law requires that LLRW be shipped to the Ward Valley site if that site becomes operational, even though other, lower cost alternatives might otherwise be available.[43] PG&E assumes a LLRW disposal cost of $509 per cubic foot in 1997 dollars, or $180 million in total. Disposal costs represent 17% of the total decommissioning cost estimate. PG&E uses a 7.5% escalation factor for LLRW disposal costs. PG&E points out that over the past 12 years, disposal costs at existing LLRW disposal sites have escalated at even higher rates. From 1986 to 1997, burial costs have escalated 22.6% annually at the Barnwell, South Carolina facility, and 10.8% annually at the Washington state site.

ORA recommends an escalation factor of 5% for LLRW disposal. ORA notes that PG&E indicated that the 7.5% escalation assumption reflects a contingency for the uncertainty of the costs of disposal at the Ward Valley site. ORA contends that the assumed cost of $509 per cubic foot already reflects a contingency for such uncertainty, and that the use of a 7.5% escalation factor represents inappropriate compounding of contingencies. ORA believes that lower cost alternatives to disposal at the Ward Valley site may be available to PG&E, although it does not specify where.

Discussion

Even though the parties ostensibly accept PG&E's decommissioning cost estimate, including the LLRW disposal element, and the issue before us is whether to accept PG&E's 7.5% or ORA's 5% assumed escalation rate, we find it necessary to first address the costs of disposal.

[43] The Low-Level Radioactive Waste Policy Act, Pub. L. 96-573, 94 Stat. 3347, (42 ((2021b to 2021j, (1980).)

While considerable uncertainty surrounds the eventual means and cost of disposal of Diablo Canyon LLRW, we accept PG&E's assumption that all LLRW will be shipped to the Ward Valley site for disposal at a cost of $509 per cubic foot in 1997 dollars. The estimate is conservative, i.e., sufficiently high, in light of the $337 per cubic foot charge for disposal at the Barnwell site and the $100 per cubic foot charge at the Envirocare site. It is also conservative in that it reflects the current requirement to use Ward Valley if it is operational. Transportation costs can be estimated with some degree of certainty. Speculation about alternative sites in the absence of a transportation plan is fruitless at the present time, although alternatives may surface in the future. Clearly, there is an economic incentive for PG&E and other LLRW generators to seek any possible alternatives to incurring high costs for disposal at the Ward Valley site. The possibility of those alternatives appears sufficiently remote at present that we can disregard them.

The Redwood Alliance argues that PG&E's assumed LLRW disposal cost of $509 per cubic foot is not sufficiently conservative. As support for this argument, the Redwood Alliance points to evidence contained in a report by F. Gregory Hayden.[44] Dr. Hayden's report concludes that there is excess capacity for the disposal of LLRW in the United States, and that new disposal facilities are not needed and would not be economically or financially viable. Among other things, the report states that a cost estimate of $1,000 to $1,500 per cubic foot for Ward Valley disposal is often mentioned by representatives of industry and

[44] *Excess Capacity for the Disposal of Low-Level Radioactive Waste in the United States Means New Compact Sites are Not Needed,* F. Gregory Hayden, PhD., Nebraska Commissioner, Central Interstate Low-Level Radioactive Waste Compact Commission, December, 1997.

advocacy groups. The report further asserts that the cost could approach $2,500 per cubic foot.

We accept PG&E's LLRW disposal cost estimate. We next must consider PG&E's case for a 7.5% escalation factor. The South Carolina and Washington state nuclear waste disposal facilities experienced high cost escalation in the past decade. The experience in the nuclear industry suggests that cost estimates tend to be unreasonably conservative. It is reasonable to extrapolate the past experience of those facilities to the Ward Valley site over the next several decades for planning and for funding purposes. We note that the developer of the Ward Valley site forecasts that costs will decrease once the facility is operational, if ever. While we do not discount this assertion completely, the experience in the nuclear industry counsels caution. The prospect of cost reductions does not undermine PG&E's assumption of 7.5% annual increases through 2035.

The evidence also shows that the 7.5% factor reflects a contingency for the uncertainty of LLRW disposal costs. It is important not to confuse this escalation factor with the contingency factor built into the initial estimate of decommissioning cost. PG&E also proposes that the Commission adopt a 40% contingency factor for the initial unescalated cost estimate, as it did in the last GRC. According to PG&E, this 40% contingency factor addresses not only engineering uncertainties, but also financial, regulatory, and industry uncertainties. According to PG&E witness Winn:

> "Maintaining this [40%] level of contingency accommodates the increasingly uncertain regulatory and business environment in which the plant operates. For example, the estimate of the cost of disposal for low-level radioactive waste assumes that the Ward Valley, California, disposal facility will be operational and supporting decommissioning operations by the year 2000. Any further delay in the scheduled opening of the Ward Valley site will ultimately increase costs." (Exhibit 6, p. 14C-5.)

The 40% contingency factor proposed by PG&E accommodates uncertainties such as those associated with estimating costs at the Ward Valley site, as well as a number of other uncertainties in the legal, regulatory and business environment. This is a distinct issue from the issue of how costs, once estimated, will escalate over time. PG&E has provided adequate support for its 7.5% LLRW disposal escalation factor.

9.3.5.1.9 Combined Escalation Rate

PG&E combines the escalation rates for labor and disposal costs discussed in the two previous sections with escalation rates for contract labor, materials, and "other" costs to arrive at an overall, constant escalation rate of 5.5% per year. To arrive at this number, PG&E first takes the simple average of these five escalation rates for each year of the analysis from 1998 to 2035. PG&E then takes the simple average of the series to arrive at a factor of 4.32%. Next, it escalates the resulting escalation rate by a 25% contingency factor to arrive at an adjusted factor of 5.4%. Finally, it rounds the result upwards to 5.5%.

Using the year 2000 as an example, the labor, contract labor, burial cost, materials, and other escalation factors proposed by PG&E are 3.56%, 3.32%, 7.50%, 1.81%, and 3.22%, respectively. (Exhibit 6, Table 14C-2; Exhibit 334, p. 8.) The simple average of these escalation rates is 3.88%. PG&E increases this average by 25% to yield a contingency-adjusted escalation rate of 4.85% for the year 2000. The 4.85% figure is averaged with similarly computed averages for every other year of the analysis. As noted above, PG&E actually uses its constant escalation factor of 5.5% for the year 2000 (and every other year in the analysis).

The 25% contingency factor used by PG&E to develop its composite escalation factor is separate from the overall 40% contingency factor that PG&E

recommends for engineering, financial, regulatory, and industry uncertainty. PG&E states that it used a 25% escalation contingency in the last GRC.

FEA argues against the 25% escalation contingency, contending that it double counts contingencies when combined with the 40% contingency factor proposed by PG&E. FEA notes that the cumulative effect of the 25% escalation factor is substantial. PG&E's proposed annual contribution to the trusts would be reduced by $26.1 million, or more than 75%, if the 25% contingency factor were removed.

Discussion

The argument that PG&E's combinesd escalation factor results in "double counting" misapprehends the distinct functions of the initial cost estimate contingency factor (the 40%) and the cost escalation uncertainty (the 25%). As we have already explained, the overall 40% contingency factor proposed by PG&E accommodates engineering, financial, regulatory, and industry uncertainties in the initial cost estimate. Adding an additional contingency factor to protect against long-term escalation of costs in actual decommissioning scenarios has been justified by PG&E and accepted by this Commission, in prior cases.

9.3.5.1.10 Conclusion - Diablo Canyon Decommissioning

ORA and FEA have argued, but have failed to prove that components of PG&E's analysis of nuclear decommissioning trust funding requirements contain calculation errors, are based on outdated information, are excessively conservative, and are methodologically flawed. ORA estimates that its proposed revisions to PG&E's fund balance calculations result in $500 million more than what PG&E forecasts, and that its proposed revisions to PG&E's cost estimates result in $500 million less in costs than what PG&E forecasts. This hopeful assessment is not consistent with the experience of the American nuclear industry. Bearing in mind our initial observation about the speculative nature of forecasts 15 or more years in the future, we do not ascribe great precision to ORA's estimates. It is not reasonable to conclude that the Diablo Canyon decommissioning trusts are adequately funded at this time for the costs of future decommisisoning.

Accordingly, the recommendation of ORA and FEA that no funding of the Diablo Canyon decommissioning trusts be authorized in this GRC is rejected. We accept the arguments of the Redwood Alliance and PG&E that the current level of funding be continued but reduced to reflect 1997 trust balances and the assumed 11% return on equity investments in the trusts. Application of these assumptions results in an annual payment into the trusts of $26.5 million. This determination is appropriate given the continuing operation of Diablo Canyon for the benefit and convenience of the ratepayers who will continue to pay into the trusts. We will have an opportunity to again review the trusts' funding status in the Nuclear Decommissioning Cost Triennial Proceeding in not more than three years. It fully conforms with statutory guidance as well as our policy on funding the trusts.

9.3.5.2 Humboldt Decommissioning

9.3.5.2.1 Non-Qualified Trust Tax Treatment

PG&E has determined that early decommissioning of the Humboldt Unit 3 nuclear power plant makes sense and should be undertaken. PG&E states that it has already begun limited decommissioning work. In addition, as explained in the following section, PG&E is proposing to spend up to $7 million to obtain permits for an on-site dry cask storage facility for nuclear fuel that would allow early decommissioning of Humboldt Unit 3. To fund this activity, PG&E

proposes that it be authorized to use the non-qualified Humboldt decommissioning trust.

Tax benefits are created when funds from the Humboldt Unit 3 non-qualified trust are spent on decommissioning activities. PG&E states that there currently is not an explicit rule about how these tax benefits should be treated for ratemaking purposes. PG&E maintains that it makes the most sense economically to spend dollars from the non-qualified trust first, because the non-qualified trust does not receive preferential tax treatment. PG&E proposes that it be authorized to use the tax benefits associated with the withdrawal of funds from the non-qualified trust.

PG&E explains that each dollar which is withdrawn from the non-qualified trust and spent on decommissioning activities generates a dollar of tax-deductible expense. Currently, PG&E uses the money generated by that deduction to fund additional decommissioning activity. Thus, each $0.59 withdrawal from the non-qualified trust provides funding for approximately $1.00 of decommissioning activity. PG&E requests that the Commission affirm this approach to fund Humboldt Unit 3 decommissioning activities. PG&E states that it would otherwise have to withdraw $1 from the non-qualified trust for each $1 of decommissioning activity, and set up a mechanism to reduce revenue requirements at some point in the future by the tax benefit generated by the tax deduction.

PG&E's recommended approach of using the tax benefit to fund decommissioning activity is reasonable and is therefore approved. The alternative of establishing a mechanism to return the tax benefit to ratepayers adds additional complexity without any discernible benefit. ORA contends that resolution of this issue is premature, but PG&E is proposing to begin spending decommissioning funds now.

Based on the foregoing determination, PG&E does not propose to collect additional funds for the Humboldt Unit 3 decommissioning trusts. No party proposed that additional funding be authorized at this time.

9.3.5.2.2 Dry Cask Storage Facility

In order to proceed with early decommissioning of Humboldt Unit 3, PG&E needs to obtain a license from the NRC to remove spent fuel from the spent fuel pools, where it currently is stored, and to move it into on-site dry cask storage. PG&E has an idea of what the costs of obtaining the license and constructing the dry cask storage will be, but it does not know for sure. PG&E notes that currently, no such container is licensed for an area with the seismic risk of Humboldt.

PG&E proposes that it be authorized to spend up to $7 million from the Humboldt nuclear decommissioning trusts to obtain permits from the NRC for an on-site dry cask storage facility. ORA initially opposed this proposal because PG&E at first did not want to commit to early decommissioning until it obtained the necessary permits. The stalemate was broken following cross-examination by the Redwood Alliance which demonstrated that major savings could be achieved by the early decommissioning of Humboldt Bay Unit 3. Approximately $4.5 million per year in avoided O&M costs (in 1997 dollars) could be realized for the 10-year period 2006 through 2015, and possibly longer if PG&E is forced to continue storing fuel after 2015. In addition, PG&E can avoid the costs of building a $2 million fuel transfer structure. Further, by disposing of LLRW from Humboldt Bay before the Ward Valley facility is operational, substantial savings may be realized.[45] PG&E now agrees that it makes sense to proceed with early decommissioning at this time, and ORA has dropped its opposition to the expenditure of up to $7 million for licensing of on-site dry cask storage.

Discussion

It is reasonable for PG&E to take this significant step towards early decommissioning of Humboldt Bay Unit 3 at this time even if the estimate of savings from avoiding disposal at the Ward Valley site cannot be fully substantiated. We approve PG&E's request for authorization to spend up to $7 million in Humboldt Bay nuclear decommissioning trust funds for the purpose of securing the NRC licenses needed for PG&E's proposed dry cask storage facility. While the expenditure of decommissioning funds on nuclear fuel-related expenses is generally inappropriate, the circumstances at Humboldt Unit 3 justify pursuit of the on-site dry cask storage option with the expenditure of decommissioning funds. Without such a storage option, early decommissioning would not be possible. If at some point in the licensing process new information suggests that early decommissioning is not cost-effective, or not in the ratepayers best interests, PG&E's decision to move forward with early decommissioning will need to be revisited.

ORA has raised the possibility that the cost of certification of on-site dry cask storage for Humboldt Unit 3 might be shared with two other nuclear power plants located in high seismic activity areas. PG&E generally agrees, but asserts that it is too soon to tell if any Humboldt Unit 3 license would provide a benefit to a future Diablo license that would justify funding some of the Humboldt

45 For the reasons discussed earlier, we do not accept the Redwood Alliance's estimates of between $31 million and $160 million in savings.

license costs out of the Diablo Canyon decommissioning trusts. PG&E would not object to tracking the costs of the seismic design and licensing activities in connection with obtaining the on-site dry cask storage license for Humboldt Unit 3, to allow the issue to be addressed in the future. Further, PG&E would be willing to affirmatively raise this issue in the Commission's triennial nuclear decommissioning cost proceeding. PG&E's proposal to track the costs of seismic design and licensing activities and to raise the issue of cost allocation in the triennial decommissioning proceeding is reasonable and will be adopted.

9.3.5.2.3 Spending Guidelines

The Redwood Alliance finds that there are questions as to what qualifies as a decommissioning expense. Accordingly, the Redwood Alliance recommends that the Commission establish formal guidelines for the withdrawal and use of money from the decommissioning trust funds. While Redwood Alliance witness Biewald contends that such guidelines are urgent for Humboldt Bay, he believes that guidelines would be useful generally for the state's nuclear facilities. In its opening brief, the Redwood Alliance recommends that the guidelines established by the NRC and by the Internal Revenue Service be adopted as Commission regulations.

PG&E takes the position that the NRC and the Internal Revenue Service already have guidelines on the appropriate use of funds from the decommissioning trusts. In addition, PG&E notes, the Commission has the opportunity to review any proposed expenditure of trust funds. PG&E contends that nothing more is needed.

Discussion

The future may reveal a need to establish guidelines for the use of decommissioning trust funds. However, the record evidence in this GRC does not provide adequate support for the establishment of new Commission regulations governing trust fund expenditures at this time. The fact that PG&E may have to make determinations whether specific costs qualify as O&M or decommissioning activity does not, alone, justify new regulations. In addition, Edison points out that if we were to adopt NRC guidelines as limiting the scope of decommissioning work (which we might want to do in establishing guidelines), utilities could not use decommissioning funds for activities such as construction of dry cask storage facilities. Accordingly, the Redwood Alliance's proposal is denied.

9.3.5.2.4 Independent Board of Consultants

The Redwood Alliance proposes the immediate establishment of an independent board of consultants to participate in the Humboldt decommissioning. In principle, PG&E is not opposed to the establishment of such a board. However, PG&E believes that it makes more sense to establish the board when the start date for the full-scale decommissioning of Humboldt is more certain. In the interim, PG&E commits to continuing its outreach efforts, to ensure that information is available to the Redwood Alliance, the Eureka community generally, and all other interested parties.

Discussion

In D.85-12-022 dated December 4, 1985, the Commission authorized PG&E to recover the cost of decommissioning the prudently constructed plant at Humboldt Bay Unit 3. (D.85-12-022, 19 CPUC2d 359, 360.) Among other things, the Commission considered a proposal by the Redwood Alliance to establish a cost monitoring system overseen by an Independent Board of Consultants. (*Id.*, 361, 364-365.) The Commission adopted its staff's suggestion that a review of decommissioning plans, including a Commission determination of whether a cost monitoring system and an Independent Board of Consultants are necessary or appropriate, should not take place until decommissioning is imminent. (*Id.*) The Commission defined imminence as "the date on which an approved depository is made available for Unit 3's nuclear waste." (*Id.*)

Even with the determination by PG&E that early decommissioning should be pursued, full-scale decommissioning will not be imminent until it appears that PG&E will secure NRC authorization for its dry cask storage plan. We therefore agree with PG&E that a decision to establish an independent board is premature. However, to ensure that timely consideration of the establishment of a board is undertaken by the Commission at the appropriate time, we direct PG&E to make a filing to initiate such consideration. PG&E shall make the filing as soon as practicable, at least six months before the date that full scale decommissioning begins, and no later than 30 days after the date that the NRC has entered an order authorizing a dry cask storage plan.

9.3.5.2.5 Ward Valley Disposal Costs

In view of the potential for extremely high and uneconomic LLRW disposal costs at the Ward Valley site, the Redwood Alliance requests that we order PG&E to actively consider and pursue alternatives to disposal of its decommissioning-generated LLRW at other facilities. Similarly, ORA expresses concern about the potentially high costs of Ward Valley disposal for all Californians. ORA recommends that we require PG&E, Edison, and SDG&E to file reports on the potential options for LLRW disposal, and the costs of those options, in the upcoming nuclear decommissioning costs triennial proceeding.

We share the parties' concerns about the potential for extremely high LLRW disposal costs at Ward Valley. It may be appropriate to address this issue in the triennial decommissioning proceeding. However, we find that the specific proposals of the Redwood Alliance and ORA exceed the scope of this GRC.

9.3.5.3 Fossil and Geothermal Decommissioning

PG&E proposes including $21.7 million in the test year to fund the costs of the eventual decommissioning of its fossil and geothermal plants. PG&E contends that its recommendation is consistent with the Commission's adopted approach to the collection of fossil and geothermal decommissioning funds during the electric industry restructuring period. (See D. 97-11-074, mimeo., Findings of Fact 38, 40, pp. 191-92.) PG&E further contends that the recommendation is supported by the cost estimates underlying the currently authorized funding levels. Finally, PG&E points out that decommissioning cost estimates are to be trued-up to reflect actual costs. To the extent decommissioning turns out to be over-funded, funds are to be returned to ratepayers. To the extent that decommissioning costs turn out to be higher than can be covered by the funds, the additional costs become recoverable transition costs.

ORA and FEA oppose this request. ORA asserts that according to PG&E's own estimates, no additional ratepayer contributions are necessary to pay for the amount of decommissioning costs that ratepayers will incur. ORA explains that PG&E's $21.7 million estimate is based on an expected total decommissioning cost of $443.4 million, less $172.4 million which has already been collected, with the remaining amount of $271 million to be collected over the next 13 years. ORA contends that the pending sale of a number of PG&E's facilities renders PG&E's analysis of costs over 13 years moot. ORA notes that under the terms of pending sales of generation facilities, the buyers will assume the costs of dismantling and removing the facilities Finally, ORA contends that the

$172.4 million already collected is more than sufficient to cover the remaining site remediation costs.

Discussion

PG&E has not demonstrated that additional ratepayer funds are needed to decommission its remaining fossil and geothermal facilities. PG&E has not shown that it gave appropriate consideration to additional plant divestitures that were pending when this GRC record was submitted. The fact that overcollections are trued up in the future is not sufficient grounds for allowing collection of additional funding at this time. We therefore deny PG&E's request for inclusion of $21.7 million in 1999 rates for fossil and geothermal decommissioning costs.

9.4 Public Purpose Programs

PG&E proposes electric public purpose funding of $200.6 million (1999 dollars) and gas public purpose funding of $33.1 million (1999 dollars). ORA generally supports these estimates. No other party addressed this topic.

PG&E's proposed level of funding for electric public purpose programs includes energy efficiency activities; research, development and demonstration activities; and renewables programs. Minimum levels of funding were established in AB 1890 and codified in Sections 381 and 382. In D.97-02-014, the Commission set the funding level at the minimum statutory levels proposed by PG&E. On the gas side, PG&E's proposal is equal to the amounts authorized for 1996 for the energy efficiency and low-income energy efficiency programs, consistent with the principles underlying AB 1890.

PG&E's proposed public purpose program funding levels are consistent with our earlier determinations and are hereby adopted.

9.5 Customer Information System (CIS)

9.5.1 Introduction

PG&E needs a CIS to support service order processing, meter reading, billing, credit and collections, payment processing, customer care, marketing and sales, reporting, and data security. PG&E installed its CIS in 1964, and has made significant modifications to it in the intervening years. PG&E refers to this system, as currently being modified, as its Legacy CIS (LCIS). PG&E states that changing technology and the demands of electric industry restructuring have impacted its CIS, requiring significant upgrades to the system and its capabilities.

In the last decade, PG&E made several attempts, since abandoned, to accomplish major upgrades to its CIS. In its 1990 GRC, PG&E received funding for its 1989-1993 CIS Rewrite project, a phased rewrite of the CIS. In 1993, after spending millions of dollars, PG&E abandoned this project. In 1994 and 1995, PG&E undertook development of a non-core CIS (nCIS) to meet the needs of PG&E's 200 largest customers using a client server technology. PG&E terminated the nCIS project in 1995, after completing the system analysis and design programming phases and beginning system testing. More recently, after issuing a Request for Proposal in August 1995, PG&E contracted with IBM to purchase and modify an off-the-shelf system in March 1996. PG&E spent $44.2 million on the IBM Integrity project in 1996 and 1997, $34.2 million in 1996 alone. The IBM Integrity project was then terminated in 1997.

PG&E has determined that the LCIS cannot accommodate the requirements of industry restructuring.[46] Since 1997, PG&E has begun conversion of its CIS to a new technology called Genesis. The LCIS is currently operating in parallel with Genesis. PG&E anticipates completing the Genesis project in 2001, at which time the LCIS will be retired.

PG&E requested that the adopted GRC revenue requirements for 1999 reflect the inclusion of $146.7 million in capital additions and $20.5 million in expenses to build and continue operations of the LCIS / Genesis system. By a motion filed on July 2, 1999, PG&E requested that incremental restructuring-related costs be removed from its request in this GRC. The request was made pursuant to a settlement agreement adopted by the Commission in D.99-05-031. Based on data submitted in this GRC record in Exhibit 418, PG&E requested in its July 2 motion that a total of $4.057 million in 1999 CIS-related incremental expenses (in 1999 dollars; $3.704 million in 1996 dollars) be removed from its GRC requests for Accounts 903 and 905, and that a total of $62.119 million in CIS-related capital additions be removed from its GRC request for common plant. As discussed in Section 12.1 of this decision, we adopt PG&E's motion.

ORA accepts PG&E's expense forecast but recommends that the authorized capital additions be reduced. With the removal of $62 million in restructuring-related CIS capital additions from PG&E's GRC request, ORA's

46 The Commission recently addressed operational problems with PG&E's billing system in D.99-06-056. In doing so, it noted PG&E's testimony that the CIS billing system is "old and fragile," and bears "the burden of over 30 years of changes to a monolithic system not originally designed for either its current roles or to accommodate such dramatic business changes." (D.99-06-056, mimeo., p. 4.)

primary capital additions recommendation is the removal of $44.2 million in costs for the IBM Integrity project. ORA also recommends that $40 million in savings assertedly attributable to the LCIS / Genesis investments be reflected in the adopted revenue requirements.

Enron also accepts PG&E's expense forecast and, like ORA, recommends that $40 million in CIS-related savings be reflected in the authorized revenue requirement. Enron recommends that no capital additions allowance be made, claiming that ratepayers have already paid $80 million for past CIS replacement efforts.

There are no disputes with respect to the test year expense estimate for CIS operations, which we adopt as reasonable. The CIS-related issues before us are whether to adopt PG&E's, ORA's, or Enron's capital additions recommendations, and whether to impute up to $40 million in CIS-related savings as recommended by ORA and Enron.

9.5.2 Basis for Recommendations

9.5.2.1 Qualifications of Witnesses

PG&E asserts that ORA witness Cheng of Financial Economic Consulting (FinEcon) and Enron witness Comnes of MRW & Associates lack significant education, training, credentials, and experience in the architecture, development, and management of large CIS projects or other large computer applications. According to PG&E's point of view, Cheng cannot claim expert opinion as a basis for his recommendations, and many of his conclusions are without foundation. Similarly, according to PG&E, a general background in ratemaking alone does not qualify Comnes to evaluate the costs of PG&E's CIS projects.

ORA's and Enron's CIS witnesses are not experts in the field of large-scale CIS development and management. With respect to technical CIS issues where resolution of a disputed fact depends on such expertise, the testimony of ORA’s and Enron’s experts should be given less weight than the testimony of PG&E’s witnesses. The latter clearly have far more pertinent experience and education in the CIS field.

This does not mean, however, that ORA’s and Enron’s CIS witnesses are not qualified to address PG&E’s CIS revenue requirement request in this GRC. On the contrary, both witnesses are fully qualified to offer credible opinion evidence on the economic and regulatory matters at issue. In particular, they are qualified to review PG&E’s showing, propound discovery requests, review internal corporate documents, industry literature, and similar sources of data, and draw conclusions therefrom. As Enron points out, PG&E’s position would be correct if Comnes testified on how to build, develop, manage, or implement a CIS project. However, he testified on the level of CIS costs previously funded by ratepayers and the reasonable level of CIS costs that should be included in revenue requirements. Essentially the same can be said for Cheng. Any generalized assertion that ORA’s and Enron’s CIS testimony lacks foundation cannot be sustained. For the most part, the disputed CIS issues arise at the confluence of technical CIS matters and matters pertaining to evolving industry and regulatory conditions that impact CIS requirements. In several respects, Enron’s and ORA’s experts are as knowledgeable in the latter area as PG&E’s CIS experts.

9.5.2.2 Estimation Methods

To arrive at its CIS recommendation, ORA first developed independent estimates of the cost of a basic CIS using comparable costs of other utilities. ORA also evaluated historical costs and a revised version of PG&E's costs, then averaged the results. We address ORA’s analysis in more detail later. At this point we comment on PG&E's claim that its detailed bottom-up estimate, which looks at CIS as a composition of parts, is superior to ORA's top-down method, which looks at the CIS as a whole.

PG&E's approach is utility-specific and precise, whereas ORA's comparable utility approach takes into consideration information that may not be fully applicable to PG&E's CIS. However, each method has strengths and weaknesses. For purposes of determining the reasonable level of CIS capital additions that should be incorporated into revenue requirements, a utility-specific, bottom-up estimate is not necessarily preferable if the underlying calculation is merely an accounting exercise of collecting costs charged to the project. In setting utility rates, we need to evaluate the reasonableness of the assembled costs. Evaluating whether the utility-specific CIS costs are significantly different from those incurred by other utilities that have developed comparable CIS projects is a legitimate and valuable tool for determining the reasonableness of a bottom-up analysis. We believe that the better way to develop a reasonable CIS-related revenue requirement forecast is to evaluate and weigh all of the relevant evidence.

9.5.3 Prior Ratepayer Funding of CIS Projects

Enron contends that PG&E's ratepayers have already fully funded the amounts necessary to implement a CIS system comparable in quality to the Legacy / Genesis system for which PG&E is seeking recovery in this GRC. Accordingly, Enron opposes authorization for additional funding in this GRC. Enron starts with a review of PG&E's CIS projects in the past decade, and PG&E's claims that the changing regulatory environment contributed to PG&E's termination of its CIS projects. According to Enron:

> CIS Rewrite PG&E justifies abandonment of the CIS rewrite project by reference to the Commission's allowance of rate negotiations

with large industrial customers, which assertedly changed the scope and cost of the project. However, Enron notes, PG&E witness Karlsson acknowledged that the Commission had been allowing negotiated rates for several years prior to 1993. Moreover, Enron notes, the witness was not aware exactly how the allowance of negotiations with customers would impact a CIS system. Finally, according to Enron, despite Karlsson's testimony that a regulatory “paradigm shift” affecting CIS requirements occurred in 1993, he could not testify as to what events occurred which caused such shift.

<u>nCIS Project</u> PG&E argues that there was a major shift in the Commission’s approach to deregulation that rendered the nCIS effort obsolete. In particular, PG&E witness Karlsson referred to the Commission’s move from the “Poolco” and wheeling concepts in 1994 and 1995 to the idea of direct access in 1996 and 1997. Enron contends that the witness was unable to clearly delineate the differences between wheeling and direct access, and was unable to identify resulting differences in programming which would compel PG&E to abandon the CIS it had been pursuing.

<u>IBM Integrity Project</u> The fact that a packaged, off-the-shelf solution could improve time-to-market and reduce risk provided justification for the IBM Integrity project. Enron points out that PG&E’s witness acknowledged that a packaged solution has reduced flexibility and that “[g]iven the pace of change and new requirements imposes on all California utilities, any off-the-shelf package would have difficulty meeting PG&E”s requirements unless an effective two-way dialogue to set requirements and limit changes was established with the PUC.” On cross-examination, the witness admitted that, in the absence of such dialogue to set the requirements for direct access, any off-the shelf package would have had difficulty in meeting PG&E’s needs. Enron acknowledges that the regulatory environment was rapidly changing in the 1995-97 time frame, but claims that no one was more aware of that than PG&E. Enron further acknowledges that PG&E’s cancellation of the IBM Integrity project in 1997 may have been due to its inability to handle the accelerated requirements for direct access and corresponding additional functionality, but claims that PG&E’s decision to go with an inflexible, off-the-shelf system in a time of rapid changes must be questioned.

> <u>LCIS / Genesis</u> While this project is not scheduled to be completed until 2001, Enron contends that the inability of PG&E's CIS system to meet Commission mandates for direct access must be considered in evaluating the reasonableness of PG&E's funding request.

Enron concludes that PG&E's reliance on the constantly changing regulatory environment as justification for the failed attempts to upgrade the CIS is without merit. Enron next reviews the authorized funding of PG&E's CIS projects in previous GRCs. Enron concludes that these efforts have already been funded by the ratepayers in the amount of $80 million, that this exceeds the reasonable estimates of the cost of a CIS, and that ratepayers should not have to fund the same project twice. Enron's ratepayer funding analysis is summarized below:

> <u>1990 GRC</u> In D.89-12-057, the Commission approved $2.3 million per year in incremental expense ($3.2 million per year in 1996 dollars) related to PG&E's requested funding for its CIS Rewrite project. The Commission referred to an estimate by Deloitte, Haskins and Sells (DH&S) that the total cost of the CIS rewrite was $44.3 million, plus or minus 20%, to be incurred over seven years (1989-1995). Of the total, DH&S estimated that $21.5 million could be met by redirecting existing resources to the rewrite effort. Thus, the incremental cost was $22.8 million. (34 CPUC2d 199, 241.) Enron acknowledges PG&E's rebuttal testimony, in which PG&E states that its request in the 1990 GRC was only for incremental funding. Enron counters that the non-incremental part of the project was already embedded in rates.

> <u>1993 GRC</u> In PG&E's test year 1993 GRC, the Commission rejected incremental CIS project funding, but accepted an amount for customer billing and accounting equal to recorded 1990 amounts. Enron contends that by doing so, the Commission approved a level of funding which included the previously authorized $2.3 million annually in addition to $3.6 million in annual funding that continued to be embedded in PG&E's rates.

> <u>1996 GRC</u> In its 1996 GRC, PG&E sought a 60% increase in funding for Customer Billing and Accounting. The requested amount was based on a showing of its 1993 recorded spending. According to Enron, the result is that from 1996 forward, PG&E's rates have embedded within them the 1993 CIS levels of spending.

Enron contends that the combined impact of these three rate cases has been ratepayer funding of PG&E's CIS projects over the 1990 to 1998 period in an amount equal to at least $80 million (in 1996 dollars). Enron recommends that, at a minimum, the reasonable costs of a ratepayer-funded CIS should be reduced by $80 million to reflect this previous ratepayer funding.

Noting PG&E's claim that ratepayers have benefited from the terminated CIS projects, Enron responds with the assertion that any benefits received by ratepayers have been both meager and short-lived. For example, PG&E claims the functionalities that were completed over the 1991 to 1994 time frame as ratepayer benefits. According to Enron, however, these capabilities will have been replaced upon the completion of the LCIS / Genesis project.

Enron also takes issue with PG&E's claims of benefits for the IBM Integrity project. PG&E claims that of the $44.2 million spent on the IBM Integrity project, $33.4 million remains used and useful, has been or will be incorporated into the LCIS / Genesis system, and thus represents a ratepayer benefit. For example, PG&E claims that $7.9 million was paid to IBM for preparing "functional specification defining PG&E's CIS requirements" and thus remains useful. Similarly, PG&E states that its personnel spent $6.3 million defining the functional requirement of a replacement CIS, which is also useable in LCIS / Genesis. Enron disputes the contention that these are ratepayer benefits.

PG&E disputes both of Enron's contentions: that ratepayers have paid at least $80 million for CIS since 1990, and that ratepayers received no benefits from the terminated CIS projects. Specifically, PG&E disputes Enron's interpretation of the 1990 GRC decision, in which Enron asserts that in addition to authorizing incremental funding for the CIS rewrite, the Commission approved the redirection of existing resources to the rewrite effort. PG&E witness Brooks contends that Enron's interpretation is a gross misinterpretation of D.89-12-057.

PG&E claims that ratepayers paid $26.6 million in rates for incremental CIS project expenditures adopted by the Commission from 1990 to 1998, assuming inflation at 3%. PG&E further claims that ratepayers received benefits of at least $36 million from the CIS Rewrite and other CIS replacement efforts even though these systems were not totally completed.

Discussion

We reject the formulation of the underlying premise of Enron's proposal to reduce the reasonable cost of CIS capital additions by $80 million: that ratepayers are paying again for a CIS replacement that they have already paid for in rates. Including the capital costs of the failed project in ratebase does not constitute double payment if those costs in fact provided benefit for ratepayers. The issue is whether ratepayers should have to pay the capital costs of a CIS replacement project that never became used and useful or otherwise provided benefits. The first question we must answer is how much ratepayers have provided in CIS project funding since the 1990 test year. The record is not as clear as either Enron or PG&E would have us believe. Assumptions about inflation, amounts included in the 1993 and 1996 GRCs, incremental costs, and embedded costs have a lot to do with whether PG&E's estimate of $26.6 million or Enron's estimate of $80 million is correct.

PG&E's estimate of $26.6 million is clearly the lower bound of the range. PG&E asserts that it represents only incrementally authorized funding.   PG&E would have us believe that it could accomplish what DH&S estimated in 1989 was $21.5 million worth of CIS Rewrite work with the redirection of existing resources, at no added cost to ratepayers. Brooks testified that:

> "The resources that were to be redirected would continue to perform their current work assignments in addition to the work on the CIS Rewrite. Funds were not to be redirected away from previously approved internal efforts in order to pursue the CIS Rewrite Project." (Exhibit 30, p. 1-44.)

DRA (ORA's predecessor) advocated in that case continuation of what it termed a "patchwork approach" to upgrade of the PG&E system, which was accomplished by existing employees. In rejecting this approach and approving the CIS upgrade project, the Commission accepted these statements about how more than $20 million in project work could be accomplished at no incremental cost (lesss patchwork, more contribution to a systematic upgrade.) The Commission clearly understood that it was approving a project costing between $35 million and $53 million ($44.3 million plus or minus 20%). (34 CPUC2d 199, 241-242.) The Commission clearly understood that approximately half of the project's costs would be funded with the incremental expense authorization and the other half would be accomplished through redirected staff efforts that were already included in rates.

Because of the uncertainty associated with the underlying assumptions, we are not persuaded by Enron' argument that ratepayers have provided as much as $80 million in CIS funding since the 1990 GRC. What is clear is that the Commission approved $3.2 million in incremental annual CIS funding (in 1996 dollars). Since approximately half of the total 1990 CIS project funding was assumed to be incremental and the other half was assumed to be non-incremental, we may assume that PG&E spent approximately $6.4 million per year in CIS development-related costs for the period from 1990 through 1998.

This yields an estimate of total PG&E capital spending on CIS development of approximately $57.6 million for the nine-year period. This is in the predicted range forecasted by the Commission in 1989. We conclude that it is reasonable to assume that over the last three GRC cycles, PG&E has spent $55 million to $60 million on CIS projects. However, it is not clear how much of that spending was related to the "patchwork approach" of keeping its existing legacy system up and running while new project development proceeded. In the absence of this analysis, we conclude that this is an absolute upper bound for the range of estimated capital spending on a new CIS system.

The second question is whether ratepayers have received benefits from the funding they provided. The fact that costly CIS projects were terminated before completion is troubling, and PG&E's reliance on evolving industry conditions, such as the advent of negotiated rates, as reasons for project termination may be overstated. Still, we accept PG&E's expert testimony that while the CIS Rewrite and CIS projects were terminated, components were put into operation and thus became used and useful. We further accept PG&E's estimate of $36 million in ratepayer benefits from these projects. We address competing claims regarding the benefits of the IBM Integrity project in a subsequent section.

PG&E has made significant capital expenditures in the past decade to develop an upgraded CIS system. Based on the reasonable assumptions of between $27 million and $ 55 million in capital spending for new project development and at least $36 million in ratepayer benefits, there is rough equivalence in the benefits and capital costs ratepayers would be charged with carrying.[47] The proposed disallowance is rejected. The result would be different if we had been unable to identify ratepayer benefits that would permitted us to conclude that in some sense the projects were used and useful for the benefit of the public, notwithstanding the fact that they were uncompleted.

9.5.4 Reasonable Costs for Required CIS Capabilities

9.5.4.1 Overview

With the transfer from this GRC of $62 million in requested CIS capital costs associated with implementation of electric industry restructuring, our task is to determine the reasonable capital cost of a basic CIS system that would accommodate all distribution utility needs except those considered in the Section 376 process.

We first observe, as ORA does, that if just $62 million in capital expenditures from the 1997 through 1999 period are related to restructuring, then PG&E’s overall request for $147 million indicates that the investments PG&E asks ratepayers to fund deliver functionalities not related to electric industry restructuring. We recognize PG&E’s position that significant, but unquantified, non-incremental restructuring costs remain after the removal of the $62 million request from this GRC. Still, a significant portion of PG&E’s GRC request is for the costs of a basic CIS that would be needed in the absence of industry restructuring. We evaluate the reasonableness of PG&E’s proposed CIS capital additions with this background in mind.

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[47] Ratepayer cost would be substantially less than this amount annually and cumulatively, since ratepayers would be amortizing the capital investment and paying return on unamortized investment.

Because PG&E, ORA, and Enron all addressed the reasonableness of PG&E's total request of $147 million in their briefs, of necessity we do likewise where necessary, notwithstanding the removal of restructuring related expenses.

9.5.4.2 PG&E's Position

PG&E contends that the reasonableness of its bottom-up cost estimate is validated by data published in the June 22, 1998 issue of *Information Week*. As reported, the Electric Power Research Institute's (EPRI) project manager for advanced billing and customer assistance, concluded that re-engineering a legacy customer information system costs utilities from $30 to $70 per customer. According to PG&E, the EPRI data indicates that one would expect that PG&E's CIS re-engineering project would cost between $150 and $350 million.

To further support its position that its CIS request is reasonable, PG&E performed a comparables analysis of the CIS project costs of 24 utilities. PG&E used only data from utilities which had completed their CIS projects, and omitted data which involved only planned or incomplete replacement projects or CIS upgrades, for which cost data is assertedly not comparable to PG&E's replacement project. PG&E concludes from this analysis that for a utility with four to eight million customer accounts, the costs of a CIS replacement project would be between $88 million and $144 million, before California's significant additional restructuring costs for CIS are considered. PG&E concludes that this result validates its bottom-up projection, showing $146.7 million in 1999 capital for LCIS / Genesis project including electric industry restructuring costs.

As additional justification and support for its total CIS request, including the restructuring-related components, PG&E describes the size and complexity of its CIS, its response to restructuring, and the implications for CIS funding requirements. PG&E makes the following assertions.

Because it is a dual-commodity utility with over 8 million accounts, and given the complexity of the gas and electric regulatory structure under which it must operate, PG&E of necessity has what is probably the largest CIS system used by any gas and / or electric utility in the nation and perhaps the world.

PG&E's CIS is so highly integrated and complex that even the smallest modifications involve high levels of risk and associated cost.

Electric industry restructuring and emerging gas unbundling present particularly substantial challenges for the CIS, requiring new functionality of the highest degree of complexity.

Although restructuring policies were conceptually developed over several years, most of the specific details, which must be known before programming can begin on the necessary modifications to CIS, were not finalized until 1997, shortly before restructuring was to begin. (See D.97-05-040 and D.97-10-087.) The Commission's timelines for market changes in California were considerably shorter than the 24 to 40 months ideally required for making extensive CIS improvements and replacements.

Given the time constraints for implementing the new market structure, PG&E necessarily chose a method for system implementation that allows for programming development while maintaining system performance. Central CIS functions such as correct tariff implementation, knowing which customers are on the various tariffs and rate options, and consistently billing the customers accurately had to be continuously operable during development and changeover to the new system.

California's existing regulations and tariffs affecting CIS are complex. For example, where Indiana has one state-wide franchise tax, in PG&E's service territory there are dozens of different tax jurisdictions. PG&E contends that there are hundreds of such non-restructuring-related complexities which make a California large utility's CIS more costly than those in most other states.

Massive changes to the CIS are required by California's unprecedented rapid electric restructuring. Modifications in CIS functionality, none of which were set forth specifically enough to begin programming until 1997, include revenue cycle unbundling, a two-page bill, changed wording on the bill, unbundling of the bill, consolidated billing, and third-party billing.

Restructuring requirements add to the number and volume of bills and to the volume of transactions per day, well over and above the 250,000 bills and two million transactions per day PG&E's CIS had to process before restructuring. Multiple-party meter reading, billing coordinated with Energy Service Providers (ESPs), and increased volume of *ad hoc* reporting are basic features required to implement various restructuring orders.

For the short-term, LCIS modifications are necessary to meet the direct access and Gas Accord requirements and deadlines. The LCIS project will assure that CIS is capable of providing unbundled billing (including calculation and tracking of CTC recovery), direct access [and gas supplier] switching information, direct access record keeping, complete revenue reporting on an unbundled basis, third party billing, customer information to ESPs, and metered data transfer with ESPs. Modifications to CIS will also meet other legal and regulatory compliance items, such as rate changes and refunds, and ongoing system operation and maintenance. These additional new functions require the purchase and installation of new, much more powerful hardware in order to upgrade existing processing equipment, storage capacity, and operating systems, and the purchase and installation of complex new system software.

To meet both regulatory and business needs, PG&E is enhancing the LCIS mainframe system, has added an interface to the mainframe so that new Genesis modules can be added to the system and existing data can be accessed, and is partitioning the overall system into functional areas so that individual pieces can be worked on and implemented while minimizing the impact to the balance of the system.

At this time, neither the LCIS nor the Genesis system alone is fully capable of fulfilling PG&E's needs in this new restructured market. The LCIS / Genesis approach was PG&E's least-cost and, by early

> 1997, its only contingency plan for timely complying with AB 1890 and Commission requirements, once the five-year phase-in of direct access was removed. LCIS / Genesis actually costs about $50 million less than IBM Integrity, which could not timely accommodate direct access with no phase-in.

Preferring its bottom-up approach to determining CIS capital spending needs, PG&E generally does not favor the use of comparables analysis. Moreover, PG&E takes the position that ORA's comparables analysis, described in the following section, is seriously flawed and should not be relied upon to evaluate the reasonableness of PG&E's CIS funding request. PG&E's criticisms of ORA's analysis include the following:

> ORA's sample of 12 comparable utilities is too small to provide reliable results, even though ORA witness Cheng acknowledged that a sample size of 20 to 25 companies was important to obtain valid statistical comparison, and that the minimum would be 10 to 20 companies.
>
> ORA included in its sample utilities with as few as 500,000 customers, without checking that the smaller utilities, or their CIS systems, were adequately comparable to PG&E's. Moreover, ORA included a municipal utility with only 325,000 total gas and electric customers, but 220,000 water customers to exceed the minimum threshold of 500,000 customers. Inclusion of this utility alone reduced ORA's average comparable CIS cost by over $2 million. In addition, according to PG&E's viewpoint, ORA inappropriately excluded larger utilities from its sample.
>
> Most of the utilities in ORA's sample had fewer than one million customers, yet PG&E contends that CIS costs are correlated with the number of accounts. According to PG&E's comparables analysis, CIS costs for utilities with between 500,000 and two million customers are between $22 and $56 million, whereas CIS costs for companies the size of PG&E are between $88 and $144 million. PG&E faults ORA's failure to weight its comparable data for the number of customers.

ORA did not consistently count the number of customers for multiple commodity utilities.

ORA did not conduct sensitivity analysis to test the effects of outside factors on the results of an analysis.

ORA did not normalize the comparable analysis data for scope of CIS work, status (complete, in progress, or planned), project duration, full replacement or upgrade, inflation, multiple commodity, and number of customers.

ORA's comparables analysis relies too heavily on data from the *Chartwell CIS Report*. Utilities self-report data to Chartwell, and there are no requirements to provide any assurance of consistency of that data among the companies reviewed in this report. ORA's consultant did not call any of the 12 utilities whose Chartwell data it used in its calculations in order to verify that the reported CIS cost figures were current and complete. PG&E contends that published material regarding CIS costs is unreliable because of companies' concerns about fully reporting "sensitive" data, differing accounting practices and dissimilar project management parameters.

ORA included CIS cost data for SoCalGas but excluded Edison and SDG&E. PG&E performed a limited analysis of Edison's CIS upgrade costs, which appear to total upwards of $253 million, including, actual and projected costs of $83 million from 1991 through 1997 and a projection in the Section 376 proceeding of another $170 million from 1998 through 2001 to modify key CIS metering and billing processes.

ORA's analysis assumed that SoCalGas' CIS replacement costs was $62.385 million, but according to PG&E this cost only covered costs in 1996 and 1997, whereas, SoCalGas' total CIS costs were actually $114 million for the project's full duration from 1989 to 1997.

9.5.4.3 ORA's Position

Based on a comparative analysis of the costs incurred by other utilities to develop a CIS, ORA found evidence that, it believes, strongly suggests that other utilities have spent much less than the amounts for which PG&E is requesting recovery in this GRC to replace or significantly upgrade their CIS system. ORA's comparative analysis was based on information obtained from detailed industry research, case studies, decisions of other states' public utilities commissions and other public documents. It was based on 12 utilities with over half a million customers.

ORA rejects PG&E's argument that ORA inappropriately included utilities smaller than PG&E in the comparable analysis. ORA notes that PG&E is the largest utility in United States and, by definition, there cannot be a utility as large or larger than PG&E. ORA also rejects PG&E's argument that none of the comparable utilities in ORA analysis is facing the EIR mandates. ORA notes that its comparable analysis is for the cost of a base system for a utility that is not going through regulatory restructuring. In particular, according to ORA the base system estimate does not include the cost requested by PG&E for implementing direct access / restructuring, the $44.2 million cost for the abandoned IBM Integrity project, or the so-called 'litigation' capital cost of $3.1 million.

ORA determined that the base CIS cost of major utilities with over half a million customers was in the range of $30 to $50 million. ORA adopted the high-end of the range, $50 million, as an estimate of the reasonable cost for a base CIS system. PG&E contends that this estimate is close to PG&E's own estimate of $46.7 million for a base system. In addition, since the costs reported in its comparable analysis are total costs for utility CIS projects, whereas the cost requested by PG&E in this GRC is only a partial cost (because PG&E's CIS system will only be 50% complete by the end of 1999), ORA contends that the base CIS cost estimated in the comparables analysis is already on the high-side.

According to ORA, the 1998 *Chartwell CIS Report* which it used as a primary data source contains extensive, comprehensive, and, significantly, unbiased data on CIS costs incurred by other utilities. The Chartwell Report reflects industry surveys as well as case studies compiled through proprietary interviews with 34 utilities chosen on the basis of their survey responses, published industry information from outside vendors (press releases, news articles, etc.) or general knowledge of the CIS activities. Hundreds of utility executives, vendor representatives, consultants and others were interviewed to compile the information contained in the Chartwell Report. The report represents hundreds of hours of research undertaken for the purpose of saving a utility executive from unnecessarily covering the same ground, and the Chartwell editors and researchers have access to information that no one person could ever uncover alone.

ORA criticizes PG&E's comparables analysis, which is based on ORA's analysis, claiming that PG&E manipulated the data with false and erroneous assumptions. ORA contends that PG&E selectively excluded its own costs and included other utilities' costs. For example, according to ORA, PG&E only included capital costs for its own CIS and not expenses, but cannot provide assurance that its estimates for other utilities only included capital costs. ORA further contends that PG&E seemingly made arbitrary adjustments to reported cost figures. With respect to SoCalGas, which faces the same gas industry regulatory requirements as PG&E, ORA asserts that PG&E did not adequately explain why it adjusted the $62.4 million estimate adopted in D.97-07-054 as the complete cost of SoCalGas' CIS to $114 million.

As another example of PG&E's alleged "pumping" up the CIS of other utilities, ORA claims that PG&E ignored other Commission decisions and source documents. For instance, PG&E claims $80 million to be the CIS cost of Cincinnati Gas & Electric (CG&E), including $62.3 million in capital costs. However, ORA notes, the Ohio Public Utility Commission only allowed $29.75 million as the reasonable cost. The Ohio decision states that:

> "the Commission finds that CG&E failed to sustain its burden of showing that $62.3 million should be found to be part of the reasonable original cost of the CSS [Computer Service System] asset. Based on the evidence of record in this proceeding, the Commission finds that $32.55 million of the cost of CSS is not reasonable … As discussed above, lengthy delays contributed significantly to the cost overruns experienced in the developing the CSS. As detailed in the Staff Report and staff testimony, CG&E invested in system where costs greatly exceeded benefits. Given the factors described above, it is unreasonable to expect that significant portion of the CSS costs would be recoverable from ratepayers. Moreover, as indicated by the staff, the company identified only $20 million in tangible benefits associated with the CSS project. Accordingly, the staff's recommendation to allow $29.75 million … as an estimate of the reasonable cost of the CSS is appropriate." (Ex. 283, p. 11; 1996 Ohio PUC LEXIS 873.)

ORA further contends that PG&E mistakenly assumed that Long Island Lighting Co. (LILCO) had spent $80 million in developing its CIS. According to the Chartwell Report, LILCO stated that the cost of $50 million to $80 million was too high to justify the CIS investment. ORA finds no justification for PG&E's choosing a number that LILCO clearly rejected in their decision process.

As another asserted flaw in PG&E's comparables analysis, ORA points out that instead of relying on the CIS costs estimated by the respondent utilities, PG&E re-estimated the CIS costs for almost half of the utilities in its analysis using an estimated cost of $20,000 per person per month. Thus, PG&E is assuming the average annual cost for each person assigned to the project to be $240,000. ORA contends that this assumption is unrealistic. ORA points to evidence (in Exhibit 301) showing that salaries for Year 2000 programmers have not reached the "astronomic levels" of $100 an hour or more that some observers initially predicted, but have risen steadily from about $40 an hour to about $60 an hour. ORA contends that by selecting such a "high and unrealistic labor cost," PG&E increased the CIS estimates for these comparable utilities by nearly 100%.

With reference to the claim that California's restructuring is more rigorous and demanding than other states, ORA asserts that PG&E has not established that its CIS system is so different from other utilities, due to different regulatory requirements, that meaningful comparisons to other utilities cannot be drawn.

In addition to its comparables analysis, ORA made the assumption that historical costs provide a good estimate of current cost of a CIS, after adjusting for inflation. Starting with the 1989 DH&S estimate of $44.3 million, which was based on a bottom-up study of the components and labor costs of replacing CIS, ORA estimated that the current cost of a CIS replacement would be $72.2 million.

9.5.4.4 Enron's Position

Enron supports ORA's analysis, and claims that PG&E's underlying case in support of the $147 million in CIS capital additions is grossly inadequate. Enron criticizes PG&E's comparable cost analysis, claiming that PG&E made adjustments that included all of the dollars spent by other utilities on their CIS rewrites or new systems, while the dollar figure PG&E used for its own expenditures represented only the portion for which it is seeking funding in this proceeding. Enron notes that PG&E testified that the entire project from start to finish will cost an estimated $240 to $290 million. While ratepayers are only being asked to fund $147 million in this GRC (before removal of the Section 376-eligible costs), Enron is concerned that PG&E will seek ratepayer reimbursement for the remainder of the project costs in the future.

In response to PG&E's claim that the reasonableness of its $147 million capital additions request is shown by the EPRI estimate that the per customer cost of reengineering a legacy CIS is $30 to $70 per customer, or a total of $150 to

$350 for a utility of PG&E's size, Enron contends that PG&E is making an invalid comparison. Enron explains this is because the $147 million sought by PG&E represents only about half of the total project costs PG&E expects to incur.

9.5.4.5 Discussion

Notwithstanding PG&E's contention that its bottom-up calculation fully justifies its CIS capital additions request in this GRC, we prefer to have an independent basis for assessing the reasonableness of its bottom-up calculations. As we determined earlier in this decision, PG&E has incentives to augment its spending, which underscores the importance of having such corroboration. An analysis of the CIS expenditures incurred by other utilities can be a useful tool for making such a reasonableness assessment.

Unfortunately, we do not find that either ORA's or PG&E's comparative analyses can be relied upon to make anything but crude and broad conclusions. We will not repeat in detail the criticisms that PG&E and ORA leveled at each others' analyses. We simply note that, for the most part, the criticisms are valid. Particularly problematic are the small sample size and inclusion of smaller utilities in ORA's analysis, and the unjustified manipulation of data in PG&E's analysis. In total, if not in every detail, the criticisms serve to undermine the value of the analyses.

Based on the evidence before us, we are prepared to conclude only that a properly conducted comparative utilities analysis would most likely yield an estimate which is no lower than ORA's estimate of $30 to $50 million for a base CIS (i.e., one that does not meet advanced electric industry restructuring needs), and which is no higher than PG&E's estimate of $88 to 144 million for a base CIS. Since PG&E has reduced its GRC capital additions request by $62.1 million, from

$146.7 million to $84.6 million for a base system, it is clear that its request falls within this very broad range of possible reasonableness.

PG&E's use of EPRI data adds little to our determination of the reasonableness of PG&E's request. It is based on a single magazine article, and PG&E did not show that it reflects an independent, impartial analyses. Moreover, PG&E did little to demonstrate that the EPRI analysis was free of the types of flaws that were found in the comparatives analyses made by ORA and PG&E.

ORA's historically-based estimate of $72 million for a CIS replacement also has several weaknesses and should be given little weight. ORA used a general CPI inflation factor that did not accurately account for the specific effects of inflation on CIS costs. The original estimate by DH&S was for a CIS with hardware and functionality necessarily different from PG&E's current LCIS / Genesis project. PG&E has shown that even a base CIS needs to be different from the system envisioned by DH&S in 1989. As PG&E witness Karlsson testified, the CIS Rewrite project would now be obsolete even if PG&E had completed it.

PG&E presented evidence that most software projects will experience one or more restarts prior to completion and operation. PG&E asserts that this evidence is borne out by the Standish Group's "CHAOS Study," which found that 31% of all software projects are canceled before completion and that the majority of initiated projects are stopped and restarted, often several times. PG&E witnesses Taboada and Karlsson presented testimony that PG&E's experiences, in which its CIS efforts were only partially completed and redirected into new and better projects, are not unusual. If anything, this testimony does more to explain delays than it does to explain the reasonableness of costs for which PG&E seeks recovery.

PG&E went to considerable lengths to describe the details of its LCIS / Genesis project, and the impacts of industry restructuring on its CIS capital spending requirements. With the removal of restructuring implementation costs from this GRC, much of this justification is removed as well, as it does not pertain to the requirements of a base CIS. In addition, PG&E's detailed system descriptions lack analyses of the costs associated with the various complex undertakings it must pursue. Nevertheless, PG&E has made a persuasive case that it needed to accomplish significant upgrades to its base CIS. We find that PG&E's decision to proceed with the LCIS / Genesis approach was a reasonable response to meet the demands placed upon its system. Except for costs associated with the IBM Integrity project, discussed in the following section, and except for our earlier determination that the reasonable CIS capital addition costs should be reduced by $20 million, we accept as reasonable PG&E's requested capital additions. We note that ORA determined from PG&E's work papers that the portion of PG&E's overall CIS request attributable to a base CIS was $46.7 million. This compares favorably with ORA's comparatives analysis. It further reinforces our view that the primary dispute between PG&E and ORA over CIS capital additions pertains to the IBM Integrity project.

Enron's concern that PG&E will eventually seek additional CIS funding, because the total amount requested now (including the $62 million transferred from this proceeding) represents about half of the total project, is premature. If PG&E comes before the Commission to seek ratepayer funding of additional CIS project costs, it will again have the burden of proving that such request is fully justified.

9.5.5 IBM Integrity System

PG&E's requested CIS capital additions include the $44.2 million that it spent on the abandoned IBM Integrity effort in 1996 and 1997. According to PG&E, the need to cancel the project resulted from no fault of its own, and the effort began in good faith. PG&E maintains that the effort was rendered unworkable when the Commission rejected plans for a five-year phase-in of direct access, and instead decided upon granting direct access eligibility for all electric customers on January 1, 1998. PG&E refers to the March 13, 1997 Proposed Decision of ALJ Wong on Direct Access Issues as the defining event that notified it of the Commission's policy of no phase-in of direct access. The IBM Integrity project was terminated the following month.

Despite the cancellation, PG&E maintains that most of the work was used in the LCIS / Genesis project, and that the amounts spent on the IBM Integrity project were not lost. PG&E wrote off $10.8 million of the project's costs, and asserts that the remaining $33.4 million is in effect used and useful.

ORA claims that PG&E mismanaged the IBM Integrity effort, and recommends that the entire $44.2 million request be disallowed. ORA relies on internal PG&E documents which indicated that there were numerous problems with the project and that the project had been assessed as having a high risk of failure. ORA also recommends exclusion of capital expenditures of $3.1 million of reserve held for the IBM Integrity System in case of billing or other disputes with IBM. ORA notes that PG&E admitted that there were no disputes with IBM, and that all invoices were paid.

ORA contends that when PG&E was considering a new CIS vendor in early 1996, PG&E knew that an off-the-shelf package such as the IBM Integrity system could not meet its needs for a CIS. ORA contends that in the rapidly changing regulatory world for California electricity, PG&E knew that a system with such reduced flexibility would not work unless there was a way to limit the changes. PG&E acknowledges this in its rebuttal testimony:

> "Given the pace of change and new requirements imposed on all California utilities, any off-the-shelf package would have difficulty meeting PG&E's requirements unless an effective two-way dialogue to set requirements and limit change was established with the CPUC." (Exhibit 30, p. 3-6.)

ORA contends that PG&E should not have expected to establish such a two-way dialogue with the Commission with respect to any aspect of electric restructuring, particularly direct access phase-in.

To further support its position that PG&E should have known that IBM Integrity System was likely to fail, ORA points to an assessment of the IBM Integrity project in the latter part of 1996, after efforts to implement the IBM Integrity project were underway. PG&E hired the San Francisco Consulting Group, a division of KPMG Peat Marwick, which presented a "Project Review and Risk Assessment" of the IBM Integrity Project on November 22, 1996. ORA contends that the San Francisco Consulting Group report supports the contention that PG&E was aware that the IBM Integrity system would not be sufficiently flexible in the changing regulatory environment. ORA rejects PG&E's contention that the report is evidence that the project was managed properly. On the contrary, ORA contends that the report suggests otherwise, and that, in fact, it predicted some of the problems that PG&E experienced due to the limits of the IBM Integrity system.

As noted earlier, PG&E's primary justification for early cancellation of the IBM Integrity project is that in early 1997, the Commission allowed for the possibility of full direct access as of January 1, 1998 (later changed to March 31, 1998), without the multi-year phase-in that was originally envisioned by the Commission. However, ORA contends that the possibility of no phase-in of direct access was foreseeable in early 1996, before PG&E chose the IBM Integrity system.

While PG&E witness Brooks explicitly declines to blame the Commission for the regulatory constraints that affected CIS, he also testified that elimination of the direct access phase-in had the effect of costing ratepayers millions of dollars. In response to this position, ORA contends that PG&E was well aware that the schedule for direct access was subject to change before it decided on IBM as a vendor for its CIS in early 1996. In particular, PG&E was aware of the contents of the Commission's "Preferred Policy Decision" for electric industry restructuring (D.95-12-063, as modified by D.96-01-009). As noted in the March 1997 Proposed Decision of ALJ Wong on Direct Access Issues, the Preferred Policy Decision "provided a great deal of flexibility regarding the phase-in approach," and the "Commission solicited comments on whether a minimum phase-in schedule was even necessary." Thus, ORA contends, in the first few days of 1996, well before choosing the IBM Integrity system in March, 1996 and gaining board approval for its new CIS project in July, 1996, PG&E knew that there was a possibility it would have to be ready to serve all direct access customers by the onset of restructuring, then planned for January 1, 1998.

In addition, ORA notes that when PG&E filed comments on ALJ Wong's Proposed Decision on March 21, 1997, PG&E stated that it "ha[d] been pursuing – and continue[d] to pursue – a plan of action to prepare for direct access in 1998 in advance of Commission decisions on a number of implementation issues." PG&E witness Brooks agreed that these comments indicated that PG&E knew that it might have to provide direct access to all customers on January 1, 1998. ORA further notes that PG&E filed comments indicating that the proposed decision was generally consistent with PG&E's preparations for direct access, and that "there [were] no technical constraints to providing all customers with the opportunity to choose direct access by January 1, 1998."

In rebuttal to ORA's testimony that the IBM effort was simply abandoned without producing benefits, PG&E identified $33.4 million in ratepayer benefits associated with the $44.2 million spent on the IBM Integrity project. PG&E acknowledges that it has included the entire $44.2 million in IBM Integrity costs in its GRC filing, despite the fact that it only quantifies $33.4 million in benefits associated with such spending. PG&E takes the position that the remaining $10.8 million write-off was incurred in good faith.

ORA takes issue with PG&E's claim that there were as much as $33.4 million in benefits associated with transferring functionalities from the discontinued IBM Integrity system to the LCIS / Genesis effort. ORA asserts that neither PG&E's direct testimony on CIS nor accompanying workpapers even mentioned that there were any quantifiable benefits associated with the decision to abandon the IBM Integrity project and move to the interim LCIS architecture. PG&E's direct testimony only described its conclusion as of April 1997 that the IBM Integrity system could not meet the accelerated requirements for direct access, and that it was not technically feasible to fully replace the existing CIS system by January 1998.

Discussion

ORA has cast substantial doubt on the reasonableness of PG&E's decision to proceed with the IBM Integrity project in 1996. In deciding upon the IBM Integrity project in 1996, PG&E chose a risky approach to upgrading its CIS capabilities. When it made the decision, PG&E was aware, or clearly should have been, that the IBM Integrity system was not sufficiently flexible to allow direct access implementation unless direct access was phased in over a period of several years. However, even though the Preferred Policy Decision indicated that direct access should be phased in, it clearly allowed for the possibility of more immediate implementation of direct access. The Preferred Policy Decision provided adequate notice in the early days of 1996 that different approaches to direct access implementation were possible, and therefore, that it should proceed with the possibility in mind of a revised direct access implementation schedule.

PG&E claims that the IBM Integrity project was a reasonable and prudent undertaking. However, this claim depends on PG&E's assumption that it could have protected itself against immediate implementation of direct access by maintaining a dialogue with its regulators. Such an assumption is not justified. PG&E should know that it cannot dictate the terms of regulation. We conclude that PG&E has failed to demonstrate clearly and convincingly that it should collect the full cost of the IBM Integrity effort from ratepayers. It should only collect the costs demonstrated to have yielded benefits to the LCIS / Genesis project.

We find that PG&E has demonstrated that a significant portion of the IBM / Integrity effort is being incorporated into the LCIS / Genesis project. We further accept as reasonable and justified PG&E's determination that $33.4 million associated with the IBM Integrity project is used and useful, and should be included in allowable CIS capital additions. However, for the reasons stated earlier, we reject PG&E's proposal to include the amount associated with the $10.8 million write-off of the project's costs. Ratepayers should not have to pay for PG&E's assumption of the risk of deciding on the inflexible IBM Integrity approach.

We accept ORA's proposed exclusion of $3.1 million that PG&E held in reserve in case of billing or other disputes with IBM. Ratepayer funding that is designated to take care of potential problems with IBM now that the Integrity Project is concluded is not necessary or appropriate. The above disallowance may be recoverable from IBM, and the recovery will accrue exclusively to PG&E shareholders.

9.5.6 CIS Savings

ORA and Enron recommend that we impute to the revenue requirement calculation an assumed $40 million in savings associated with the implementation of new CIS technology. In a 1995 business case, the San Francisco Consulting Group indicated that savings in operating efficiencies of $40 to $50 million were expected with a new CIS. ORA and Enron fault PG&E for failure to reflect savings or benefits that were forecast in the 1995 business case and other internal documents. ORA contends that the 1995 business case was the economic analysis that PG&E's board relied upon in approving the IBM Integrity project. ORA rejects PG&E's contention that the 1995 business case was prepared only for a "theoretical CIS system replacement that was never built" and was not applicable to LCIS / Genesis. ORA faults PG&E for never having conducted any further cost-benefit analysis to justify its switch from IBM Integrity to LCIS / Genesis. ORA asserts that it has identified substantial potential savings that PG&E can achieve with the new CIS system.

Enron asserts that expecting significant cost savings from a new CIS such as PG&E's is consistent with industry practice. Indeed, the record evidence shows that three times in the past ten years, PG&E has done an assessment of projected savings from its various CIS rewrite attempts. These assessments have produced estimated savings ranging from $40 to $90 million. Enron further notes that the Commission has recognized anticipated savings as a critical factor in the approval of SoCalGas' request for funding for a CIS system

PG&E contends that in making this recommendation, ORA and Enron rely inappropriately on outdated documents that pertained to previous CIS projects, and are not applicable to the LCIS / Genesis project. PG&E takes the position that there are no quantifiable, hard savings associated with the latter.

PG&E explains that when its board of directors authorized funds for the ongoing effort to replace its CIS in July 1996, it was done with the knowledge that project leaders foresaw no quantifiable hard savings for the project. The cost estimate submitted for the board's review included the results of a cost-benefit study which indicated that the IBM Integrity project would yield no quantifiable benefits and had a negative net present value (NPV) of $235 to $275 million. PG&E considered CIS replacement a "business imperative," a project necessary to stay in business. PG&E states that while there was an expectation of $90 million in benefits over the life of the CIS, these soft (i.e., not quantifiable) benefits were not included in the NPV analysis.

PG&E claims that it is the foregoing analysis, not the 1995 business case or other documents on which ORA relies, upon which the board gave its approval. According to PG&E, the 1995 business case and the other documents have nothing to do with LCIS / Genesis.

Discussion

ORA and Enron have not demonstrated that CIS-related savings which were identified in 1995, in the San Francisco Consulting Group's business case as part of the RFP process, can reasonably be attributed to the LCIS / Genesis project now underway. Their requests to reflect such savings in the adopted revenue requirement are therefore denied.

PG&E's internal approval of the LCIS / Genesis project was not conditioned upon quantifiable, hard savings. On the contrary, PG&E approved the project because it was determined to be necessary to implement Commission requirements, including restructuring, and to continue providing basic customer services such as billing.

PG&E has shown that the 1995 business case was not the basis for the IBM Integrity cost estimate approved by the board of directors on July 17, 1996. Also, the business case assumed the savings would be derived from functionality that was planned at the time, but that functionality is not being built in the LCIS / Genesis system. PG&E notes that some of the functions to which the business case attributes savings are now found in several of the IT projects. We address IT savings in Section 9.6.

PG&E has also shown that other documents relied upon by ORA do not support a finding that we should assume hard savings for the LCIS / Genesis project. One, a 1995 presentation on core process improvement initiatives, is a single page from a longer presentation that deals with the narrow, non-CIS subject of the management of meter reading effectiveness. The other pertains to the 1989 DH&S study. We concur with PG&E that this study from a decade ago should not be used to support a finding of savings for the current CIS project.

9.5.7 Conclusion - CIS

Through its unopposed July 2, 1999 motion to withdraw its request for incremental restructuring costs, PG&E has reduced its request for CIS-related capital additions to $84.6 million. We have determined that PG&E's CIS capital additions request should be reduced to reflect $10.8 million in costs associated with the IBM Integrity project which were written off by PG&E. Accordingly, we adopt an estimate of CIS capital additions of $73.8 million.

ORA contends that PG&E's LCIS / Genesis project produces capabilities which will allow PG&E to be in a superior competitive position. ORA urges that we provide assurance that captive ratepayers are not being required to fund development of a strategic asset that would give PG&E an unfair competitive advantage. PG&E responds that the LCIS / Genesis system offers only basic functions such as metering, billing, payment processing, credit and collections, and customer contact. While we share ORA's concern from a conceptual standpoint, ORA has not provided adequate factual basis for its concern in this case. At least in significant part, ORA appears to rely on outdated, early information about the IBM Integrity project and the capabilities it might have provided. We are satisfied that the funding for PG&E's LCIS / Genesis project authorized herein is the amount required for reasonable distribution utility needs.

9.6 Information Technology (IT) Projects

9.6.1 Introduction

PG&E's IT proposal in this GRC involves 13 separate technology projects. PG&E states that these projects represent a major commitment on its part to invest in new technologies which will improve both operating efficiencies and customer service. According to PG&E witness Phillips, the 13 projects represent a new and concerted effort by PG&E, begun for the first time in late 1996, to upgrade and enhance the existing IT infrastructure.

The expenses associated with these projects are included in the proposed amounts for gas and electric operating accounts and customer accounts, and the capital costs are included in PG&E's proposal for common utility plant. PG&E has also reflected expected savings from the IT projects in its GRC showing. As shown in PG&E's rebuttal testimony, PG&E requests funding for a total of $143.3 million in capital expenditures, $33.3 million in project and ongoing expenses, and has estimated associated savings of $29.1 million.

As shown in its opening brief, ORA recommends that PG&E's proposed IT-related capital additions be reduced by a total of $28.7 million, that PG&E's proposed IT expenses be reduced by a total of $15.7 million, and that PG&E's savings estimate be increased by a total of $24.6 million. TURN recommends that capital additions for one project, the Outage Information System, be disallowed. CFBF offers specific recommendations for five IT projects, and recommends IT-related reductions of $8.2 million for capital additions and $14.2 million in expenses. CFBF also recommends additional IT-related savings of $13.7 million. Enron proposes that historical IT expenditures reflected in its proposed five-year average of non-CIS common utility plant be allowed, but recommends against allowing any additional capital expenditures. Enron proposes the exclusion of PG&E's expense and savings projections for IT projects. Enron finds the difference between PG&E's proposed IT spending and estimated savings to be an unjustified mismatch, and asserts that PG&E has not provided adequate justification for its IT proposal.

In the following sections (Sections 9.6.2 through 9.6.5) we consider policy, methodological, and other issues that affect proposals for IT projects generally. In Section 9.6.6 we address issues associated with the 13 individual IT projects.

9.6.2 IT Spending Incentive

ORA contends that IT projects provide electric and gas utilities with a valuable tool for gathering customer information and offering better customer service. ORA raises the concern that PG&E is utilizing its request in this GRC to bolster its ability to react to the restructured electric world, so that customers will have a better image of PG&E's brand name, and to help position PG&E for a potentially competitive distribution market sometime in the future. Enron supports this analysis by ORA.

Excessive spending authorization for certain IT projects could have the damaging effect of having ratepayers subsidizing competitive efforts by PG&E. Because there are incentives for PG&E to augment IT spending in a manner that would better position it to offer competitive services, it is particularly important to hold PG&E to its burden of proof that each of its IT project proposals is just and reasonable.

9.6.3 Management Approval

ORA takes the position that management authorization for each IT project should be a prerequisite for inclusion of the project's capital cost in distribution rate base. ORA argues that ratepayers will be harmed if the Commission approves funding for IT projects which have not received management authorization. ORA explains that if PG&E's management rejects a project authorized by the Commission, the equivalent funding is still in the revenue requirement for PG&E to spend as it wishes. PG&E witness Phillips acknowledged that this is the case.

CFBF similarly argues that we should disallow funding for IT projects for which there is a lack of commitment by PG&E, as evidenced by a lack of internal approval. CFBF states that it not so much the actual "okay" by management that it seeks, but rather assurance that the company has performed an analysis showing that the projects are worthy of approval.

PG&E contends that requiring evidence of utility management approval of a project prior to approval by the Commission is inconsistent with forecast test year ratemaking, and has not been a criterion for acceptance of a GRC proposal in the past. PG&E argues that the schedule for processing GRCs conflicts with the schedules for its internal budget and project approval processes, and does not allow it to demonstrate management approval of certain projects. PG&E

further contends that it could not remain in business if it funded projects that were not conducive to providing safe reliable service to its customers. In response, ORA expresses the concern that certain IT projects may not have been approved by management because they are not cost-effective. ORA believes that Commission approval in the absence of management approval is tantamount to a finding that cost-effectiveness is no longer a relevant consideration in approving a project.

PG&E's IT witness acknowledged that PG&E’s IT funding request is essentially a new phenomenon, largely involving expenditures not previously addressed in a GRC. According to PG&E, this is why Enron’s historical averaging approach, discussed below, is inappropriate. However, the fact that there is no historical basis for evaluating the reasonableness of PG&E’s IT request is also an important reason why we should require a high degree of assurance that PG&E's own management has or will have approved each proposed IT project as economically justified before we ask ratepayers to provide funding.

9.6.4 Revised Cost and Savings Estimates

For certain management-approved IT projects, the cost and savings estimates that PG&E presented in this proceeding differ substantially from the estimates that were provided to management when the project was approved. For these projects, ORA contends that PG&E should be held to the cost and savings estimates presented when management authorization was sought and obtained. CFBF takes a similar position with respect to two IT projects.

PG&E defends its revised cost and savings estimates with the assertion that “[i]t is irrelevant whether [actual recorded data] is higher or lower than the original estimate, as it reflects the actual costs and / or savings associated with the work, or the most recent estimate of those costs / savings.” (Exhibit 30, p. 4-6.) In response, ORA argues that projects which cost far more and provide far less savings than originally estimated when management approval was received should not be presumed to be cost-effective.

If the cost or savings estimates relied upon by PG&E's management in approving a project are no longer valid, the reasonableness of the project is called into question. We recognize PG&E's testimony that business conditions change over the course of multi-year contracts, and that it may not be possible to realize previously estimated savings. However, the fact of changed circumstances does not alone justify ratepayer funding of a management-approved project. Where there is a significant variance for any project's original and revised cost or savings estimates, it is incumbent upon PG&E to demonstrate that ratepayer funding of that project is just and reasonable in light of current circumstances.

9.6.5 Enron's IT Project Recommendation

As noted earlier, Enron proposes allowing IT funding only to the extent that such funding was included in the 1992-1996 average of common plant costs, including IT project funding adopted in common plant in the 1993 and 1996 GRCs. Enron does not address the specific IT projects for which PG&E seeks funding in this GRC.

PG&E has had only minor IT projects in common plant in past rate cases. None of the significant costs of the 13 new IT projects at issue in this GRC are embedded in the recorded common utility plant costs for the years 1992 through 1996. Thus, the costs for the current IT project effort have never before been captured in a PG&E GRC. Also, PG&E only started capitalizing computer software costs in December 1995, yet the majority of the IT projects include large software expenditures. Thus, according to PG&E, a review of historical capital data does not result in a meaningful analysis of current projects.

Since the spending on IT projects which PG&E seeks to incorporate in revenue requirements is essentially new, PG&E is entitled to have the reasonableness of its proposed projects reviewed on the merits. Enron's approach would effectively deny such consideration because, historically, PG&E has not recorded significant capital spending on IT projects. Enron's approach is unreasonable and is therefore rejected.

9.6.6 Specific IT Projects

9.6.6.1 Outage Information System (OIS)

The OIS helps system operators in managing outages, receiving input from customer calls and other systems to help locate outages, and improving communications to customers on the status of outages. PG&E's request for the OIS project consists of capital additions of $19.4 million and 1999 test year expenses of $3.6 million.

ORA accepts PG&E's expense estimate but recommends that the capital additions be reduced by approximately $3.2 million, to $16.1 million. ORA points out that the $3.2 million difference, which, according to PG&E, pertains to 1997 recorded data, was not included by PG&E in the March Update showing or in various PG&E workpapers. PG&E's first mention of the increase to $19.4 million was in its rebuttal testimony. We reinterate our dislike of this practice by PG&E.

There is no dispute that the OIS has value to ratepayers. ORA argues that PG&E has not provided an adequate explanation of where the additional $3.2 million of booked additions can be found. However, as PG&E points out, TURN agrees with the need for the OIS project, and it does not dispute the costs for the project. We adopt PG&E's recommendation to include $19.4 million in capital additions for the OIS project. We also adopt PG&E’s uncontested expense estimate.

TURN proposes a disallowance of all OIS-related capital additions for 1997-1999 due to PG&E’s alleged failure to adequately maintain a former outage system prior to and during the December 1995 storms. We addressed PG&E’s response to the December 1995 storms in D.99-06-080 dated June 24, 1999. Among other things, we addressed PG&E’s failures associated with certain outage-related systems, and imposed a fine of $20,000 for such failures. (D.99-06-080, mimeo., p. 112, Ordering Paragraph 22.) In view of our action in D.99-06-080, we do not find TURN’s ratemaking disallowance to be justified.

9.6.6.2 Job Estimating Tools (JET)

The JET project will upgrade PG&E’s existing estimating and computer-aided design systems. PG&E’s request for the JET project is for total capital additions of $500,000, capital savings of negative $3.3 million, and test year expenses of $5.8 million. ORA supports PG&E’s JET project request. PG&E’s JET proposal is reasonable and is therefore adopted.

9.6.6.3 Correspondence Management

The Correspondence Management project provides for the scanning, electronic imaging, and workflow management of customer correspondence to improve system efficiencies. It is one of three Call Center Enhancement Projects for which PG&E seeks funding in this GRC. PG&E’s combined request for the three projects is $7.1 million for capital additions, and $1.4 million in expenses offset by an expense savings of $2.7 million for a net expense reduction of negative $1.3 million in the test year. ORA concurs with PG&E’s estimates, and does not dispute the need for these projects.

We accept PG&E's estimates for the Call Center Enhancement Projects as reasonable and hereby adopt them. Consistent with our discussion of ORA's proposal for potentially competitive services in Section 12.7, we adopt full recovery of the reasonable expenses, and deny ORA's proposal to limit recovery to 38.75%.

9.6.6.4 Intelligent Call Routing (ICR)

The ICR system directs customer calls, using intelligent call routing technology, to the appropriate Customer Service Representative based on customer needs and business requirements (e.g. Chinese language, service activation, etc.). It is the second of three Call Center Enhancement Projects, addressed in Section 9.6.6.3

9.6.6.5 Interactive Voice Response Unit (IVRU)

The IVRU uses telephone touch-tone selection to handle routine customer inquiries about account balances, payment information, and other account information, and provides customers the ability to input and receive outage related information. This system sends and receives information from the Outage Information System. It is the third of three Call Center Enhancement Projects, addressed in Section 9.6.6.3

9.6.6.6 Non-Energy Billing/Mainline Extensions (NEBS/MLX)

The NEBS / MLX project replaced the existing Non-Energy Billing and Main Line Extension accounting programs with new software modules to provide integrated accounting and reconciliation between NEBS / MLX and other PG&E financial accounting applications.

For this project, PG&E proposes overall capital additions of $11.6 million, and expenses of $920,000, offset by a savings of $1.1 million for a net expense of negative $154,000 in the test year. ORA accepts the project's capital and expense figures. Also, while it initially proposed greater savings of $2.3 million, ORA agreed that the additional $1.2 million in savings were from avoided costs that should not be included in a rate case estimate built on recorded costs.

Based on the foregoing, we adopt PG&E's capital, expense, and savings estimates for the NEBS / MLX project as reasonable.

9.6.6.7 Field Automation System (FAS)

PG&E's FAS project automates the way field service employees are dispatched, receive work instructions and report completion of work. The system links call centers and dispatchers with field service personnel through mobile data terminals installed in field service vehicles. PG&E's funding request for the FAS project includes total capital additions of $36.2 million and expenses of $3.0 million. The expense proposal is offset by savings of $4.6 million for a net expense reduction of negative $1.6 million in the test year.

ORA supports the project and agrees with PG&E's funding request, although ORA does raise the concern that the FAS represents a key strategic advantage in attracting and retaining customers in a competitive environment. However, ORA and CFBF recommend greater savings estimates for the FAS project. ORA proposes increasing PG&E's estimated expense savings by $8.7 million, resulting in a total savings estimate of $13.3 million. Alternatively, if the $8.7 million increase in savings is not adopted, ORA recommends that the entire FAS project cost be disallowed. ORA believes that PG&E's projected net savings of $1.6 million per year raises the question of whether a project costing $36.2 million in capital additions in this GRC is in the ratepayers' best interests. The $13.3 million expense savings estimate proposed by ORA was originally projected in PG&E's 1996 business case for the FAS Project. ORA contends that without these savings, the project would have a negative net present value (NPV) and thus would not appear to be cost-effective for ratepayers.

PG&E contends that its expense savings estimate was developed from actual project performance accumulated since the FAS project went operational in early 1997. According to PG&E, the project savings estimated in the business case will never be realized because the original assumptions have changed. For example, PG&E states that it did not consolidate its service dispatch centers, and it has not been able to electronically re-enter as high a percentage of completed service tags as was assumed in the business case. PG&E contends that because its current savings estimate is based on actual data, it is more accurate than the original 1996 savings estimate. PG&E takes the position that the Commission's GRC decision should be based on the most accurate data available, and that its reduced savings estimate should therefore be used.

PG&E also disputes the contention that the FAS project has a negative NPV. Moreover, PG&E argues that even if the FAS had a negative NPV, it would still be beneficial to ratepayers. PG&E witness Phillips testified that some projects with a negative NPV should be completed. As examples, Phillips refers to projects to increase safety, to comply with governmental regulations, or to meet regulatory requirements. Phillips also believes that some projects with significant "soft savings" such as customer satisfaction should go forward even if they have a negative NPV.

PG&E emphasizes its position that its current estimate of FAS-related savings is more accurate than the original estimate. However, because the savings estimate associated with the decision to go forward with the FAS project has turned out be much smaller, the relevant question is whether we should authorize funding for the FAS project or assume the original savings estimate for ratemaking purposes.

Other than a retrospective analysis which it presented as a cross-examination exhibit, and which has untested assumptions, PG&E did not present an analysis to determine whether continuing the project was appropriate. Nor do we find sufficient evidence for concluding that this project falls into the category of projects with a negative NPV that should nevertheless be completed due to a safety or regulatory mandate. Finally, we agree with CFBF witness Illingworth, who stressed that the existence and desirability of soft savings should be carefully documented, not simply claimed to exist.

Since we have insufficient basis for finding that the project is reasonable and prudent in the absence of savings that were originally projected by PG&E, we find that it is reasonable to authorize the project costs and to adopt the higher savings estimate for ratemaking purposes as proposed by ORA.

9.6.6.8 Work Management System (WMS)

The WMS will be used to schedule, prioritize, and manage all engineering, maintenance, and construction work for gas and electric distribution. PG&E's request for the WMS is for 1997-1999 capital additions of $27.8 million, with capital savings of negative $7.1 million; and for expenses of $2.9 million, offset by expense savings of negative $3.0 million for a net expense reduction of negative $118,000 in the test year.

ORA agrees with PG&E's expense estimate but contests PG&E's capital additions and savings estimates. ORA proposes 1997-1999 capital additions of $24.8 million for the WMS, a reduction of $3.0 million compared to PG&E's request. In lieu of PG&E's combined savings estimate of $10.1 million ($7.1 capital savings and $3.0 expense savings), ORA recommends total savings of $30.8 million. This represents an increase of $20.7 million over PG&E's savings estimate ($15.6 capital savings and $5.1 expense savings).

ORA's recommendation to reduce the allowable capital additions by $3.0 million is based on PG&E's 1996 overall job estimate that was approved by management. ORA contends that the $3.0 million increase is associated the transmission and generation business units, and argues that such work should not be included in the distribution rate base determined in this proceeding. In addition, ORA found that the latest monthly status report prepared by the WMS project team prior to the March Update showed the total project capital and expense was consistent with the original project estimate.

PG&E has not provided adequate justification for allowing increased project expenses. ORA has shown that the $3.0 million increase can be attributed to additional costs that arose when work was added for the benefit of non-distribution business units. Allowing the full amount requested by PG&E would have the effect of requiring distribution customers to subsidize work performed for the benefit of others. ORA's proposed $3.0 million reduction to WMS capital additions is therefore adopted.

With respect to the savings estimates for the WMS, ORA proposes that the capital and expense savings of $30.8 million estimated in the original 1996 job estimate for 1999 be used for test year savings. PG&E on the other hand believes that while savings of this magnitude will eventually be achieved as originally projected, most of the savings will not be realized until after the 1999 test year. According to PG&E witness Phillips, the WMS project was delayed by one year because of the implementation of a pilot project designed to gain information on the process changes required as a result of the new system. PG&E states that this is the reason for the reduced savings estimate in the test year.

ORA has cast substantial doubt on the contention that the WMS would be delayed by up to one year. A number of internal documents indicate that there was no significant delay in implementing WMS. Under the circumstances, it would be unreasonable to deny ratepayers the benefits associated with the project for an entire GRC cycle. ORA's proposal to adopt the originally projected savings of $30.8 million is therefore adopted.

9.6.6.9 Bill Print, Mailing and Payment Processing Center (BPM&PP),

PG&E's new billing center in West Sacramento replaces PG&E's previous billing operation located on three different floors at 77 Beale Street in downtown San Francisco. PG&E states that the new facility replaced aging equipment with new larger equipment sized to meet the distribution utility needs of electric industry restructuring, eliminated the inefficiencies at the old location, and relocated the facility out of a major earthquake zone. PG&E's request for the BPM&PP Center consists of 1997-1999 capital additions of $27.5 million and a test year savings in expenses of negative $2.6 million

ORA originally took issue with PG&E's savings estimate, recommending an additional $1.0 million in savings associated with cash float. ORA witness Cheng later agreed that these savings have already been reflected in working cash. ORA now concurs with PG&E's billing center savings estimate.

Based upon its contention that PG&E's new billing center was built with significant excess capacity, ORA recommends a disallowance of $9.1 million of PG&E's proposed capital additions of $27.5 million. ORA notes that the new facility has approximately one-third more square footage than the old facility, and is run with two shifts instead of the three shifts used in the old facility. ORA contends that PG&E could use the billing center as an outsourcing facility for other companies.

Responding to ORA's argument that the new facility is oversized, PG&E asserts that its new billing center is larger only because the old, outdated billing center was grossly undersized. PG&E contends that because its new bill format requires two pages instead of one, it takes twice as much paper to print it, doubling the floor space needed to store paper next to the printers. PG&E asserts that all of the additional square footage at the new facility is utilized to meet current billing requirements.

The second basis for ORA's excess capacity claim is that the facility is meeting its current requirements running only two shifts. However, PG&E asserts that when the facility was being designed in 1995, PG&E conducted an economic analysis to determine the most efficient design / operation combination that would yield the lowest overall cost. PG&E's options ranged from using larger equipment, fewer people, and one shift; to using smaller equipment, more people, and three shifts. PG&E found that its lowest cost option was to design the facility for a two-shift operation. PG&E thus contends that it correctly designed the facility at the least cost to ratepayers.

PG&E rejects ORA's assumption that PG&E could use the alleged excess capacity to provide potentially competitive third-party billing services, and then use such competitive services to make up the disallowance in revenues. For example, according to PG&E, ORA has not shown that PG&E could offer billing services on behalf of others without degrading the cost, quality, or reliability of its billing services to its distribution ratepayers. Yet, PG&E contends, such a finding is required under the Affiliate Rules before the Commission can ever approve a non-tariffed new product or service. PG&E further notes that there is no showing that PG&E could make up ORA's proposed $9.1 million cost disallowance in revenues even if it did seek and receive authorization to provide such billing services.

ORA has not demonstrated that PG&E built significant excess capacity into the new billing center. Given new requirements for billing, including a two-page bill, and the need for efficiencies in operations, it was not unreasonable for PG&E

to determine that it needed more space than it used in the old center. ORA notes that PG&E's own shift analysis indicated that the total costs for two-shift or three-shift operations were about the same. However, this does not demonstrate that PG&E could have built the center with significantly less capacity than it did. Based on the foregoing, PG&E's request for the BPM&PP Center is granted, and ORA's proposed disallowance of $9.1 million is denied.

9.6.6.10 Technology Integration Test Site (Test Site)

The Test Site was put in place in mid 1996 to help integrate new applications with PG&E's existing systems such as the Call Center System, Twenty First Century, and the LCIS. PG&E states that once these new systems go into production, the Test Site tests any new changes to these systems and oversees configuration management for all of the inter-related applications to ensure that changes in one system do not adversely affect any of the other systems. PG&E's funding proposal for the Test Site is for 1997-1999 capital additions of $323,000 and test year expenses of $1.4 million.

ORA recommends no funding allowance for the Test Site because this project is assertedly in the planning stage and has not gone through a formal review process. PG&E counters that it has provided evidence of approved job authorization for the establishment of the Test Site. PG&E admits that it did not perform an economic analysis, because it does so only for jobs of $1 million or more, but notes that the majority of test year costs are for ongoing O&M costs for which PG&E has provided 1997 recorded costs as assurance that these costs are reasonable.

We find that PG&E has provided adequate justification for approval of the Test Site project. ORA's proposed disallowance is denied.

9.6.6.11 Facilities Information Database (FID)

The FID project will provide a comprehensive database of information about utility facilities and will result in reduced mapping and estimating costs. PG&E's funding proposal for the FID project includes 1997-1999 capital additions of $2.2 million and expenses of $4.1 million, offset by $4.8 million of savings for a net expense savings of negative $742,000 in the test year.

ORA and CFBF propose disallowance of all costs of this project because the job estimate has not gone through formal review and has not yet been approved by PG&E management. In response, PG&E asserts that while this job had not been authorized at the time of the hearings, it was scheduled to be in late 1998. PG&E further asserts that this job has already gone through an extensive review and analysis in the FID business case. PG&E asserts that all of the six non-status quo alternatives evaluated in this business case analysis have a positive net present value, and that the overall revenue requirement for this project is negative in the test year.

As CFBF and ORA point out, it is not clear that any of the alternative projects described in the FID business case correspond to the FID project described by PG&E. PG&E has not shown that its FID funding proposal is justified. It is therefore denied.

9.6.6.12 Middleware Project

The Middleware project will provide a common communications interface between PG&E's linked software applications. PG&E's funding request for this project includes 1997-1999 capital additions of $108,000 and 1999 test year expenses of $484,000.

ORA and CFBF recommend no funding for the Middleware project because it has not yet received PG&E management authorization or undergone a detailed economic analysis. PG&E notes that this is another project that falls under the $1 million review threshold for a detailed economic analysis.

Consistent with our determination of the need for assurance of management approval based on economic justification, we find that PG&E has not provided adequate justification for ratepayer funding of this project. The disallowance proposed by ORA and CFBF is adopted.

9.6.6.13 Information Technology (IT) Upgrades

The IT Upgrades are a series of projects designed to keep existing IT systems current and to enhance those systems to increase efficiencies and improve performance. PG&E seeks to recover 1997-1999 capital additions of $10.7 million and 1999 project and on-going expenses of $9.7 million. PG&E contends that these costs are necessary to upgrade and maintain its $200 million investment in IT Projects.

ORA and CFBF recommend that cost recovery for the IT Upgrades be denied because PG&E has not identified specific IT Upgrade projects; has not yet authorized any of these projects; has not provided economic justification for the capital and expenses requested; and identifies no savings associated with these projects.

PG&E raises the issue of protecting its $200 million investment in IT projects, but does little to tie its funding requests for IT Upgrades to such protection. ORA and CFBF have demonstrated that in its IT Upgrades request, PG&E is essentially asking us to approve projects in concept, rather than specific, well-defined IT projects that can be considered on their merits. This underscores the importance of requiring assurance that PG&E's own senior management is satisfied that the projects are economically justified before we approve ratepayer funding of them. PG&E's funding request for IT Upgrades is therefore denied.

9.6.7 Summary - IT Projects

The following table summarizes the foregoing determinations of authorized capital additions, expenses, and savings (both capital and expense savings combined) for the 13 IT projects for which PG&E seeks funding authorization in this GRC. As we determined in connection with the disallowance of certain CIS-related capital additions, disallowances for IT projects are allocated to 1997, 1998, and 1999 in direct proportion to PG&E's proposed capital additions for those years.

Adopted IT Project Funding and Savings
($000)

IT Project	Capital Additions 1997-99	Test Year 1999 Expenses	Total Savings
OIS	16,127	3,623	0
JET	500	5,789	3,258
Correspondence Mgt.	2,921	397	64
ICR	1,618	488	1,161
IVRU	2,576	489	1,443
NEBS / MLX	11,556	920	1,074
FAS	36,152	2,970	13,300
WMS	24,786	2,896	30,818
BPM&PP	27,499	0	2,649
Test Site	323	1,415	0
FID	0	0	0
Middleware	0	0	0
IT Upgrades	0	0	0

9.7 Taxes

PG&E's showing on taxes includes estimates of current and deferred income tax expenses, the deferred tax reserve, property taxes, payroll taxes, and business taxes. There are no disputed issues with respect to PG&E's tax calculations. The final amount of income taxes is determined by the results of operations (RO) computer model run which incorporates the adopted capital and expense estimates. The amount adopted for payroll taxes is a function of, among other things, the wage expense resulting from this proceeding.

9.8 Working Cash

In PG&E's 1996 GRC decision, the Commission observed that the calculation of working cash warranted simplification:

> "Working cash calculations require a level of precision, complexity and sometimes controversy which are out of proportion to the significance of working cash in the greater scheme of regulation. This is one area where a simple but intuitive calculation, even lacking in imprecision, would be an improvement over the current circumstance. If we revisit this issue in a future case, we hope the parties will propose simpler methods for determining working cash." (D.95-12-055, 63 CPUC2d 570, 617.)

PG&E and ORA agree that for the purposes of this proceeding, the working cash component for the electric and gas departments and Line 401 should each be set at zero. PG&E believes that adopting a working cash requirement of zero is consistent with the Commission's observation regarding the need for simplicity in the last GRC. While TURN initially addressed the topic of working cash in its testimony, TURN did not further address it in its brief.

As additional support for this agreed-upon proposal, PG&E points out that there is additional complexity in this proceeding due to unbundling. Both the magnitude and sign of the working cash component may change in subsequent RO model runs because changes in expenses are multiplied by working cash expense lags. Also, the RO model run associated with PG&E's March Update shows that the working cash requirement by UCC can be positive or negative. PG&E notes that the FERC uses a working cash figure of zero when the working cash calculation produces a negative number, as it does in this proceeding.

Finally, in the event that we determine that a negative number is appropriate for working cash, PG&E recommends that we adopt working cash of negative $14,138,000 for the electric department, negative $2,702,000 for the gas department, and negative $1,433,000 for Line 401.

Notwithstanding our prior determination of the desirability of simplicity, as well as FERC practice, we cannot ignore the fact that adopting a zero working cash allowance would be detrimental to ratepayers in this case if the working cash calculated by the model turned out to be negative. Similarly, it would be unfair to PG&E if we adopted a zero allowance and the model calculated a positive working cash requirement. The record does not persuade us that the need for simplicity outweighs the need for reasonable accuracy in setting the utility's revenue requirement. We therefore adopt the actual computed values for working cash that were determined through the RO modeling.

9.9 Escalation Rates

9.9.1 General Issues

The general methodology used by PG&E for forecasting the labor and the materials and supplies escalation rates is the same as that developed in the 1987 GRC and used in the 1990, 1993, and 1996 GRCs. PG&E has introduced a refinement by unbundling the materials and supplies escalation rate into separate rates for six of the eight UCCs used by PG&E. The exceptions are the two public purpose program UCCs, for which PG&E uses a single, overall administrative and general expense escalation rate. ORA concurs with PG&E’s methodology for unbundling the materials and supplies escalation rate.

ORA made four recommendations in response to PG&E’s initial GRC showing, three of which were accepted by PG&E. PG&E agrees with ORA witness Lyons’ recommendation to use the Employment Cost Index for Wages and Salaries rather than the Compensation per Hour Index for the Nonfarm Business Sector to escalate labor costs in attrition years 2000 and 2001. PG&E also agrees to Lyons' recommendation to use published hard copy (as opposed to electronic) data sources. Finally, PG&E agrees, and states that it has always assumed, that both labor and non-labor escalation factors should be updated to reflect the most recent available data. With respect to this third recommendation, PG&E submitted update testimony (Exhibit 475) which sets forth updated escalation rate data. We adopt the foregoing uncontested recommendations for escalation rates in Exhibit 475.

9.9.2 Non-Bargaining Unit Escalation Rate for 1997

The only contested issue with respect to escalation rates is the 1997 labor escalation rate. PG&E recommends 3.41%, while ORA recommends 3.23%. PG&E and ORA agree on the 3.25% escalation for bargaining unit employees. The difference is attributable to their escalation recommendations for non-bargaining unit employees. For these employees, PG&E recommends an escalation rate of 3.75%, while ORA's estimate is 3.19%.

There are two sub-issues with respect to the 1997 non-bargaining unit escalation rate. First, ORA's escalation figure of 3.19% is based on planning information for 1997 available as of December 1996. However, PG&E determined that the actual 1997 base salary increase was 3.26% as of February 1997. ORA has not demonstrated why the anticipated base increase should be used when more reliable data is available. We adopt PG&E's estimate of 3.26% for the 1997 base salary increase for non-bargaining unit employees.

The second sub-issue involves the appropriate treatment of lump-sum merit payments to non-bargaining unit employees. According to PG&E, these employees received lump-sum merit increases in 1997 which had the effect of raising their total compensation increase from 3.26%, based on base salaries, to a total of 3.75%. ORA does not contest PG&E's estimate that actual non-bargaining unit labor costs increased by 3.75% in 1997. However, because the lump sum payments which constitute the difference between 3.26% and 3.75% were one-time payments and were not added to base salaries, ORA contends that the additional increase should not be reflected in the adopted escalation rate. PG&E argues that exclusion of these lump-sum payments would create a downward bias in the true percentage increase in total wages and salaries.

We seek to adopt labor escalation factors that will produce the most accurate forecast of 1999 test-year labor expenses. In doing so, the only question before us is whether inclusion of lump-sum payments accurately reflects 1997 increases in labor costs. We think it is clear that PG&E's approach is the more accurate, since it reflects the costs actually incurred by PG&E. ORA seems to rely on the fact that the lump-sum payments are one-time payments. However, the fact that these payments may not be replicated after 1997 does not change the fact of their occurrence in 1997. Accordingly, we adopt PG&E's recommendation for a 3.41% labor escalation rate for 1997.

9.10 Consultant Costs

At the outset of this proceeding, ORA filed a motion requesting that PG&E be directed to provide funding for consultants to be retained on behalf of ORA to assist ORA in reviewing PG&E's application. The motion was conditionally granted by an Assigned Commissioner's Ruling dated January 27, 1998 (January 27 ruling). Among other things, the ruling authorized PG&E to submit testimony regarding the revenue requirement impacts of the funding obligation created by the ruling, the allocation of consulting expenses to the gas and electric departments, and related matters, including the extent to which shareholders and ratepayers should be assigned responsibility for the cost impacts of the ruling. The ruling also directed the Commission's Executive Director to establish a Management Oversight Committee having responsibility for close and continuing oversight of the process of augmenting ORA's resources in this proceeding. While the ruling did not set a budget or establish a ceiling on the funding obligation, it noted ORA's estimate of $1.85 million for anticipated consulting services.

At the January 29, 1998 prehearing conference, PG&E advised the Commission that it was reviewing the January 27 ruling on legal grounds to determine what action PG&E might take in the future with respect to the ruling. (Tr. PHC, 42.) PG&E took no such action.

In accordance with the January 27 ruling, PG&E established a memorandum account to track the expenses incurred pursuant to the ruling.[48] PG&E also submitted testimony (Exhibit 21) setting forth a proposal for the recovery of consultant costs incurred as a result of the ruling. PG&E's testimony addressed the revenue requirement impacts of the consultant funding obligation, the allocation of consulting costs to the gas and electric departments, the allocation of the consulting costs between ratepayers and shareholders, and the appropriate ratemaking mechanism for the recovery of these costs. No other party submitted testimony addressing this issue. PG&E's proposal is summarized as follows.

> ORA should present a detailed report describing how it has spent the consulting funds. PG&E and other parties should have an

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48 We concur with PG&E's determination that, consistent with standard memorandum account treatment, this account should accrue interest based on the three-month commercial paper rate.

> opportunity to comment on this report as part of their update testimony. ORA's report should present a recommended allocation of consulting costs to the electric and gas departments.
>
> All consulting costs incurred by ORA in processing this GRC should be borne by PG&E's ratepayers.
>
> Consulting costs allocated to the electric department should be transferred from the memorandum account to the Streamlining Residual Account established pursuant to Advice Letter E-3514.
>
> Consulting costs allocated to the gas department should be transferred to the Core Fixed Cost Account and the Noncore Customer Class charge Account.

Pursuant to an October 30, 1998 ruling of the ALJ, on January 15, 1999, ORA submitted a report which showed consultant costs incurred and billed to PG&E, broken down by the individual consulting firms used by ORA. The report included ORA's recommendation for allocating consulting costs to the electric and gas departments. The total consulting cost billable to PG&E as of January 15, 1999 was $2.009 million. ORA recommended that $1,570,131 be allocated to the electric department and $438,869 be allocated to the gas department. ORA noted that additional consulting costs could be incurred in connection with review of the proposed decision, drafting comments, and other such assistance. ORA estimated the consultant costs for closing work would not exceed $100,000.

Discussion

PG&E's proposal that 100% of the costs of the funding obligation created by the January 27 ruling be paid by ratepayers is reasonable and is hereby adopted. The purpose of ORA's participation in this GRC, and, therefore, the purpose of providing for the funding of ORA's consultants, is to serve the interests of ratepayers. Utility shareholder participation in these costs is not warranted under the circumstances. Also, PG&E's uncontested ratemaking proposal to transfer accrued costs from the memorandum account to the respective electric and gas ratemaking balancing accounts is reasonable and is therefore adopted.

Since ORA's consultants may assist ORA in reviewing the proposed decision and in similar activities, it is not reasonable to require a final determination of consulting costs until after the issuance of a final decision on PG&E's GRC application. Accordingly, we adopt the following supplemental procedures. No later than 60 days after the issuance of a final decision in this GRC, ORA shall file a final report which states, for each consultant used by ORA in connection with this GRC and for which funding is to be paid by PG&E pursuant to the January 27 ruling, (1) the total invoiced amount of expenses incurred in connection with this GRC proceeding, (2) the amounts which ORA determines should be allocated to the PG&E's electric and gas departments, and (3) the basis for such allocations.

PG&E and other parties will have an opportunity to file comments on ORA's January 15, 1999 and final reports. Comments are due 15 days after the date ORA files its final report. In the absence of comments, or upon ruling of the assigned ALJ, PG&E will be authorized to file an advice letter pursuant to this decision for the purposes of transferring costs recorded in the memorandum account to the respective electric and gas balancing accounts, and closing the memorandum account. In the event that comments are filed, the ALJ will make a determination of the additional procedures to be followed as necessary.

PG&E has raised concerns about the contracting process and the legitimacy of certain expenses. However, the January 27 Assigned Commissioner's Ruling explicitly assigned to the Management Oversight

Committee the responsibility of ensuring that the use of internal staff resources is maximized to the extent possible, that consulting contracts are in accordance with the law, that contract expenditures are reasonable and appropriate, and that contracts are administered effectively. PG&E's legitimate concern is in obtaining reimbursement for the expenses it incurs pursuant to the ruling. PG&E's request for a "detailed accounting" is unnecessary and unwarranted except to the extent such an accounting is required to corroborate the invoiced amounts and to support the allocation of expenses to the electric and gas departments. Any comments on ORA's report shall be limited accordingly.

We are distressed to find that PG&E has been recalcitrant in responding to invoices for consultants' services. PG&E waived any objection to the January 27 ruling, and must respond to such invoices on a timely basis. PG&E shall pay interest on invoiced amounts at the three-month commercial paper rate from the original invoice dates, and shall not recover the costs of such interest from ratepayers.

9.11 ORA Report on Results of Examination

9.11.1 Access to PG&E's Books and Records

ORA's auditors were frustrated by PG&E's delays in providing data responses and by what ORA alleged was PG&E's denial of historical levels of access to PG&E's books and records as well as access to PG&E personnel. ORA believes that the Commission should reaffirm its role in regulatory oversight of PG&E and put PG&E on notice that penalties will be levied in the event of future restrictions on ORA.

PG&E acknowledges that delays in responding to discovery requests have been a challenge. PG&E contends that this GRC is unique both in its complexity and in the extent of the discovery process. PG&E also contends that ORA's concerns about access are overstated, and that ORA's proposed remedies should be rejected. PG&E agrees that ORA should have access to its books and records, including all of the books of account that the company uses as well as the on-line processes that it uses to make the entries into different accounts. However, PG&E disputes the notion that ORA should be given unlimited, unsupervised, on-line access to those portions of PG&E's SAP management system that are used for planning purposes.

Discussion

With respect to delays in discovery responses, we recognize that this is an exceedingly complex proceeding, and that this complexity has contributed to the scope and volume of discovery requests and consequent delays in the discovery process. Such delays have, in turn, contributed to the extra time that has been required to process this GRC.

With respect to the issue of access, we make the following observations. First, the record does not show that ORA was denied access to PG&E's books and records, including its SAP system, to the extent that further action on our part is warranted at this time. At least in certain respects, PG&E went to lengths to provide access, such as providing training in the use of the SAP system and providing personal computers to ORA. Second, there appears to be no dispute that Sections 309.5(e), 314, 314.5 and 771 of the Public Utilities Code grant ORA broad authority and rights with respect to access to utility information, including the utility's books and records, and access to the utility's premises. Third, existing procedures for resolving disputes over access to utility information and premises appear to be adequate. Fourth, ORA's contention that its auditors require unlimited access to PG&E's books and records is correct to the extent such access is consistent with the foregoing code sections. Fifth, consistent with due process considerations, we concur with ORA that penalties may be appropriate where a utility denies access to its premises or its books and records. Other remedies may be appropriate in some circumstances. For example, where the denial occurs in the context of an application proceeding before the Commission, an appropriate remedy might be suspension or even dismissal of the proceeding. Where the denial of access affects a specific item of expense, a disallowance with respect to that item may be appropriate.

We appreciate PG&E's expressed willingness to work with ORA to resolve all issues related to access to PG&E's book and records. In the normal course of business, we expect ORA to work cooperatively with utilities, just as we expect utilities to work cooperatively with ORA. We also expect that, more often than not, this cooperation would include the observance of such business courtesies as ORA's making prior appointments to meet with utility staff and PG&E's ensuring that its employees are fully informed about ORA's rights of access. Ordinarily, we would not expect ORA personnel to freely roam a utility's premises.[49] However, we do not in any way intend to restrict or limit our lawful rights, or those of our staff, including ORA, to pursue all lawful duties. Undoubtedly, there will be circumstances when observance of the aforementioned courtesies is not possible. For example, unannounced interviews with company personnel may be a necessary part of an audit by ORA. However, it is our hope that the need for dispensing with such courtesies, as well as disruptions to company operations, can be kept to a minimum.

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49 Where an ORA representative does find it necessary to "roam the halls," Section 771 provides that utility personnel may be present.

Finally, we observe that the transition to more competitive utility markets accompanied by new regulatory approaches does not provide cover to utilities to shirk their duties to provide the access to the Commission, including ORA, required by law. (See *Re Alternative Regulatory Frameworks for Local Exchange Carriers*, (1989) 33 CPUC2d 43,196.)

9.11.2 Verification Audit

PG&E's new SAP business system has been in use since May 1996. In order to meet regulatory reporting requirements, PG&E, with assistance from SAP, designed a "FERC translation module" that allows the corporate financial information kept in the new business system to be presented in FERC account format. At the outset of this GRC proceeding, ORA determined that it needed to have read-only, on-line access to the SAP system in order to follow the audit trail of booked costs and transactions. ORA was not able to gain such access on a timely basis. For example, PG&E did not provide ORA with access to the "controlling" or "CO" module of the system. As a consequence, ORA was not able to complete its audit of the FERC translation module. ORA requests that we require PG&E to conduct further testing of the FERC derivation process in SAP. ORA also recommends that we exercise caution when using 1996 and 1997 recorded numbers submitted by PG&E in its 1999 GRC.

PG&E fully agrees that ORA and the Commission must have confidence that the FERC translation module is accurately translating financial information contained in the new business system to FERC accounts. PG&E and ORA report that they have commenced discussions on the structure, content and timing of a verification effort. PG&E sees the purpose of such an audit as ensuring that data recorded in the new business system are accurately translated into the FERC accounts. PG&E has committed to keeping the Commission and the parties apprised of the status of negotiations with ORA as well as any agreement that may be reached.

Discussion

PG&E should offer ORA its full cooperation in providing ORA with the means of full and timely access to all components of the SAP system as necessary to allow ORA to complete the audit. ORA has estimated that with the full cooperation of PG&E, ORA will require 60 to 90 days to complete the verification audit. While ORA has suggested that the audit be considered in a separate phase of this GRC or in a new investigation proceeding, we believe that a determination of the need for, and nature of, any formal proceedings is premature. Instead, we will provide that upon completion of the verification audit, ORA shall file a report setting forth its findings, conclusions, substantive recommendations, and any procedural recommendations for formal Commission consideration thereof. Comments may be filed 15 days after ORA's report. A determination of whether and how to proceed formally will be made thereafter.

9.11.3 ORA's Proposed SAP-Related Adjustments

9.11.3.1 Capitalized SAP Costs

In May 1994, PG&E approved a $38.3 million budget for implementation of its new SAP business system. The final implementation cost of SAP, incurred from 1994 through 1997, was approximately $70.7 million. The cost exceeded the approved budget by $32.4 million, or 84.5%.

ORA contends that while one would expect some variance between budget projections and final costs, the 84.5% cost difference from original projections seems excessive. ORA believes that a 50% variance in the originally projected cost of installation is more than generous in estimating a level of reasonable cost overruns. Based on a 50% variance, ORA asserts that the total SAP installation cost that should be considered reasonable is 81.3% of the final cost (150% / 184.5%). ORA recommends that the 81.3% factor be applied to the capitalized SAP installation expenditures of approximately $13.2 million. Accordingly, ORA recommends that only $10.7 million of capitalized costs be allowed in common plant for ratemaking purposes, resulting in a reduction to PG&E's 1997 balance for Common Plant (computer hardware) Account 391 of $2.5 million.

PG&E argues that there is no reason to conclude that the capital cost of SAP were excessive. We concur. The fact that PG&E experienced significant cost overruns does not demonstrate that the actual cost incurred by PG&E was unreasonable. ORA's proposed adjustment is denied.

9.11.3.2 Annual Cost Reduction

According to data provided by PG&E to ORA, operating costs for the business systems replaced by SAP were approximately $1.3 million and $1.5 million in 1994 and 1995, respectively. In contrast, PG&E estimates the annual SAP operating cost at $26.7 million for the 1999 test year. ORA believes that such a disparity in operating costs between the old and new systems is unreasonable. ORA further notes that when PG&E decided to go forward with the SAP system, it projected annual cost reductions of $4.0 million. However, PG&E has made no provision to pass these savings on to ratepayers. ORA recommends adoption of a $4 million credit to A&G expenses for the 1999 test year to reflect the savings anticipated from implementation of the SAP business system.

PG&E's attempt to distance itself from its own estimate of $4 million in savings, because the estimate is assertedly outdated, has little merit. By PG&E's own admission, these savings were part of the original analysis of costs and benefits of SAP implementation. Clearly, the savings were part of PG&E's decision to proceed. Also, PG&E has not adequately substantiated its claim that any savings are already reflected in the 1997 recorded expense and plant data used in this GRC. In light of the substantial increase in operating costs associated with the new system, it is reasonable to pass on to ratepayers the originally projected cost savings of $4.0 million as a credit to A&G expense. ORA's recommendation is therefore adopted. As noted earlier, this determination is reflected in Account 930.

9.11.3.3 Copyright Revenues

As noted earlier, PG&E developed the FERC translation module in order to have the necessary regulatory reporting capability. ORA contends that the total cost incurred by PG&E to develop this module was approximately $5.0 million. PG&E sold the modified software to SAP pursuant to the contract between PG&E and SAP. ORA recommends that the Commission impute $5.0 million in copyright royalties amortized over a three-year period, or $1.67 million per year beginning in the 1999 test year. ORA recommends that the imputed amount be recorded in FERC Account 421, Miscellaneous Non-operating Income, and allocated 55% to electric and 45% to gas operations.

PG&E disputes the $5.0 million figure used by ORA, claiming that other cost components are included in this amount. PG&E contends that the cost of developing the FERC module was $813,998. PG&E further disputes ORA's contention that the compensation received by PG&E from SAP should be imputed as income. According to PG&E, none of the expenses incurred by PG&E in the implementation of the SAP business system are included in this GRC, and passing the compensation received from SAP on to ratepayers would compensate ratepayers for expenses they did not incur.

ORA has not shown that its proposed imputation of income from the SAP contract is reasonable or appropriate. PG&E has shown that the proposal would inappropriately reward ratepayers. ORA's proposal is therefore denied.

9.11.3.4 Retirement of Replaced Business Systems

ORA believes that it is unreasonable for ratepayers to pay a return on investment for the systems replaced by SAP. ORA recommends an increase in common plant retirements to reflect the impact of the shift of business systems from mainframe computers to the client server hardware used by the SAP system. PG&E responds by explaining that the business systems replaced by SAP ran on mainframe hardware which is used for other applications. In addition, according to PG&E, historical data is still available through these systems for inquiries and data extracts.

We are not persuaded by ORA's showing in support of additional retirements. ORA's proposal is therefore denied.

10. Cost Allocation/Separation

10.1 Unbundled Cost Categories (UCCs)

As we noted in the background section of this decision, PG&E has presented its application in a traditional bundled format and in an unbundled format with revenue requirements separated among eight UCCs: Electric Generation, Electric Transmission, Electric Distribution and Customer Services, Electric Public Purpose Programs, Gas Transmission and Storage (Non-Line 401), Gas Distribution and Customer Services, Gas Public Purpose Programs, and Line 401 - Pipeline Expansion.

This is the first GRC in which PG&E made such a separation among UCCs. As PG&E points out, unbundling is necessary to reflect and respond to the restructuring of the electric and gas industries. PG&E states that its showing follows two key cost separation decisions, both of which were approved on August 1, 1997. For electric service, D.97-08-056 separated PG&E's estimated 1998 Electric Department revenue requirement into the four functions of Public Purpose Programs, Distribution, Transmission, and Generation, with Generation revenues subdivided into nuclear decommissioning, estimated Power Exchange, and remaining revenues. (D.97-08-056, mimeo., p. 62 and Appendix D, Table II.) For gas service, D.97-08-055 clarified and approved the comprehensive settlement of PG&E gas issues known as the Gas Accord. Among other things, the Gas Accord separated PG&E's gas business into Distribution service, Transmission (other than Line 401) and Storage service, and Line 401 service.

PG&E's eight UCCs are consistent with D.97-08-055 and D.97-08-056, and should be approved. However, at issue is whether Enron's proposal for further unbundling is necessary or appropriate.[50] Enron proposes that the eight UCCs used by PG&E be expanded to a total of 19. Specifically, Enron proposes that customer services be split off from the respective electric and gas UCCs of Distribution and Customer Services. Customer services would then be divided into four new categories (metering, billing, customer accounts / service, and marketing). In addition, Enron proposes rearranging the two UCCs of Gas Transmission and Storage and Line 401 into five gas categories (production, gathering, interstate transmission, intrastate transmission, and storage / balancing).

Enron argues that its unbundling proposal would facilitate the segregation of revenue requirements in other proceedings. Enron also argues that this GRC is the most appropriate forum to identify and quantify the revenue requirements for the expanded UCCs that it proposes. Enron next argues that failure to unbundle PG&E's operations as it proposes will inhibit competition. Finally, Enron asserts that the eight UCCs proposed by PG&E do not reflect the economic and regulatory environment.

PG&E objects to Enron's UCC proposal as being outside the scope of this proceeding as established in the April 7, 1998 Scoping ACR. With respect to unbundling and competitive issues, the ACR stated:

> "To the extent necessary for determining the utility revenue requirement for regulated services that PG&E will continue to offer, allocations to competitive and monopoly services are at issue in this proceeding. This may include allocations to sub-categories of the

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[50] PG&E has identified sub-categories within the UCCs to determine the revenue requirement and satisfy other existing regulatory requirements. For example, electric restructuring requires the further separation of Electric Generation costs into fossil, geothermal, hydro, and other sub-categories. These sub-categories are not disputed.

> UCCs in addition to those identified by PG&E. The need for setting a revenue requirement which does not reflect subsidization of competitive activities necessarily brings such allocation issues into the proceeding. However, I remind parties of the purpose of this GRC as stated previously. It is not a generic unbundling policy proceeding, and it is not a forum for relitigation of matters already resolved by the Commission or for duplicate litigation of matters being addressed in other forums. Thus, for example, electric and gas revenue cycle service issues being addressed in A.97-11-004 and R.98-01-011 respectively will not be litigated in this GRC." (Scoping ACR, mimeo., p. 9.)

PG&E takes the position that Enron has not demonstrated that its proposed new categories are needed to determine PG&E's 1999 revenue requirement. PG&E further contends that Enron is attempting to accomplish what was prohibited in the Scoping ACR: relitigation of matters already resolved or litigation of matters being addressed elsewhere, and turning this GRC into a generic unbundling proceeding.

Discussion

Enron has not demonstrated that its proposal for expanded unbundling is necessary for purposes of setting revenue requirements in this GRC. It is possible that further unbundling may become necessary as developments occur in other proceedings, and it is possible that the unbundling envisioned by Enron for this GRC would eventually ease the procedural burden of segregating revenue requirements between competitive and monopoly services in future proceedings. However, the purpose of this GRC is not to anticipate future unbundling, or to ease the burden of future proceedings before the Commission.

Enron cites language in D.97-08-056 (mimeo, at p. 9) which describes the Commission's unwillingness in that proceeding to modify revenue requirements as it unbundled utility operations and allocated costs to those operations as support for its assertion that this is the proper forum for considering the inter-relationship between unbundling and cost allocation. This reliance is misplaced. We find nothing in the language cited by Enron that supports its specific proposal. In effect, Enron is arguing for its vision of unbundled services and rates. In doing so, it is making proposals that are beyond the scope of this proceeding. Additional unbundling is not necessary to set the revenue requirement at issue in this GRC and adds to an already lengthy agenda. Enron's proposal is therefore rejected. Enron's argument that failure to accomplish the unbundling that it proposes will inhibit competition is little more than an argument for further unbundling. This clearly exceeds the scope of this GRC as set forth in the Scoping ACR.

However, we recognize the concern which underlies Enron's argument: that the Commission, having rejected in D.97-08-056 an opportunity to link unbundled service structures to costs and rates, not create a procedural shell-game that avoids deciding issues of crucial significance to the development of a robust retail energy market functional for participants on both the buyer and the seller sides of the market. Our rejection of Enron's proposal in this case does not mean that we fail to recognize the significance of this issue. Since this will not be the last GRC for PG&E, there will be a forum for a proper delineation of services and costs.

10.2 Allocation of Costs to UCCs

10.2.1 Four-Factor Allocation Method

PG&E's latest revised showing in this GRC applies the results of its Effort Study and a proposed labor allocation factor which reflects O&M labor. PG&E asserts that this allocation factor is more accurate than the four-factor allocator traditionally used in GRCs to determine A&G allocations to the electric and gas departments.[51]

PG&E witness Holton asserts that labor is accepted by FERC as the basis for most allocations, that O&M labor is a causative factor for many A&G expenses, that the use of O&M labor produces allocations which are not radically different than those produced by other commonly used allocators, and that this method was adopted for PG&E in D.97-08-056.

ORA recommends the use of the traditional four-factor allocator, asserting that labor is only one of several factors affecting A&G costs. ORA contends that the four-factor allocator includes factors other than labor costs for that reason, and that the reasons for using the four-factor allocator have not changed. ORA further contends that PG&E has failed to provide any explanation why the Commission's current policy of using the four-factor allocator should be changed.

We find that the evidence in support of PG&E's position outweighs the evidence in support of ORA's position. PG&E's A&G Labor Two Factor Allocator is adopted in lieu of the four-factor method recommended by ORA as the basis for allocations to the UCCs, except as provided in the following two sections where we address account-specific allocation issues.

10.2.2 Accounts 921, 922, and 923

For unbundling Accounts 921 (Office Supplies and Expense), 923 (Outside Services), and the non-labor portion of Account 922 (Administrative Expense

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[51] PG&E refers to this factor as the "M&O labor factor" in its opening brief and as the "A&G Labor Two Factor Allocator" in its reply brief. The four-factor allocator is an arithmetic average of percentages of expenses, gross plant, number of employees, and number of customers.

Transferred), ORA contends that PG&E should have used a separate A&G Non-Labor Two Factor Allocator instead of the A&G Labor Two Factor Allocator. ORA contends that the A&G non-labor cost data collected in PG&E's 1996 Cost Unbundling Study relates directly to the costs recorded in Accounts 921 and 923, and therefore provides a more accurate basis for allocating those costs.

We are persuaded that ORA's recommended Non-Labor Two Factor Allocator produces more accurate unbundling allocations for Accounts 921, 923, and the non-labor portion of Account 922, and should therefore be adopted. PG&E's reliance on consistency as a rationale for using only the labor component of O&M expense is not persuasive.

10.2.3 Account 930.2 (Miscellaneous General Expense)

In lieu of PG&E's A&G Labor Two Factor Allocator, ORA uses an O&M Labor Allocator to unbundle the electric and gas portions of Account 930.2 costs other than Public Purpose Program costs. ORA contends that Account 930.2 contains many costs which relate to PG&E's overall operations, and that O&M labor is a more accurate allocator than A&G labor. PG&E responds that while Account 930.2 contains some O&M expense, it is primarily an A&G account.

We concur with PG&E that its justification is more substantive than ORA's, and that PG&E's position should therefore be adopted.

10.2.4 Other UCC Allocation Issues

PG&E's electric generation and electric and gas transmission costs are mapped to the Electric Generation, Electric Transmission, Gas Transmission and Storage, and Line 401 UCCs. Generally, there is no dispute that these costs do not belong in the revenue requirements at issue in this GRC. However, PG&E contends that certain generation and transmission costs belong in this GRC's revenue requirements. In this section we consider two exceptions raised by

PG&E that have not been addressed previously in this decision: electric transmission-level direct connects and third-party generation ties.

The costs of transmission level direct connects are recovered from transmission level customers in the rate design process. PG&E contends that costs of transmission-level direct connects are appropriately mapped to the Electric Distribution and Customer Services UCC, because they are not included in the facilities or services regulated by the FERC.

PG&E provides third-party generation ties pursuant to Special Facility Contracts covered by its Tariff Rule 2 or as part of the power purchase contracts. These transactions have been monitored and reviewed by the Commission, and the Special Facility Rates are specifically approved by the Commission. PG&E contends that the costs of third-party generation ties, which are accounted for as electric transmission costs and are mapped to the Electric Transmission UCC, are appropriately recoverable in this GRC. PG&E notes that third-party generation ties are not included in the electric transmission facilities or services regulated by the FERC.

The costs of transmission-level direct connects and third-party generation ties are collected from the customers and generators who receive the benefit of the services, and are not recovered pursuant to FERC jurisdiction. PG&E's proposal for the inclusion of transmission-level direct connects and third-party generation ties in the revenue requirements set in this GRC is reasonable and should be adopted. The rate design implications will be addressed in Phase 2 of this proceeding.

10.3 Reallocation of Fixed A&G

In the electric industry restructuring cost separation proceeding, the Commission addressed the treatment of fixed A&G expenses associated with the divestiture of electric generation plant. It determined, among other things, that:

> …"The utilities have not demonstrated that every type of fixed cost cannot be reduced, that is, made variable, over the medium term....
>
> "However, we are persuaded that some of these fixed A&G costs may remain following divestiture and the end of the period during which the utility operates the plant on behalf of a purchaser. On the other hand, we want the utilities to take actions to reduce their costs, especially as a result of divestiture.
>
> "It is not our intent to deny utilities an opportunity to recover reasonable costs which they actually must incur, but we must balance this with our need to ensure that ratepayers are not paying for costs that no longer exist. To the extent that the fixed A&G costs we have allocated to generation are truly fixed and continue to exist following this period, we will review and reallocate continuing fixed A&G costs to distribution using a streamlined procedure. No procedure was proposed in this proceeding. The Assigned Commissioners in this proceeding shall develop a streamlined process for this reallocation by December 16, 1997." (D.97-08-056, mimeo., p. 24.)

Pursuant to rulings of the Assigned Commissioners in the cost separation proceeding, as well as the Scoping ACR in this proceeding, on April 22, 1998 PG&E submitted additional testimony relating to reallocation of fixed A&G costs following the divestiture of its Moss Landing, Morro Bay, and Oakland fossil power plants (Wave 1 divestiture). PG&E states that pursuant to D.97-11-074, its use of the term "fixed A&G costs" in this context refers not only to A&G expenses, but also to related common and general plant. PG&E also uses the term "residual costs" to refer to this meaning of fixed A&G costs.

In this GRC, PG&E proposes to reallocate to the various electric UCCs the residual A&G expenses and common and general plant costs that cannot be directly assigned to the Wave 1 plants. PG&E surveyed its corporate services managers to determine the direct assignment of A&G expenses to the Wave 1 plants. PG&E gives as examples of unavoidable, residual costs the salaries of the corporate tax and accounting departments and the desks, computers, and floor space that such departments use.

PG&E's April 22, 1998 testimony on reallocation of fixed A&G costs did not include dollar estimates of variable A&G costs avoided by the Wave 1 divestiture or estimates of increases in distribution A&G resulting from reallocation. PG&E's specific recommendations are set forth in the comparison exhibit, at p. A-132. PG&E seeks to reallocate $5.2 million in residual A&G expenses to the UCCs and $15.5 million in residual common and general plant to the UCCs.

ORA and Enron oppose PG&E's Wave 1 reallocation proposal. ORA contends that PG&E's approach incorrectly allocates generation costs to distribution customers. ORA explains that PG&E employees will continue to operate the Wave 1 power plants during the 1999 test year, but PG&E's proposed allocation factor does not include the labor costs of these employees. As noted earlier, PG&E's cost unbundling methodology generally allocates A&G costs to UCCs based on labor costs. Thus, ORA contends, PG&E's proposed reallocation of Wave 1 A&G expenses assigns to other UCCs, including distribution, test year A&G costs that should be allocated to the Wave 1 plants.

ORA also opposes PG&E's Wave 1 reallocation proposal because PG&E's estimates of the cost reductions resulting from the Wave 1 plant divestitures are assertedly unreliable and understated. PG&E estimated the savings resulting from the Wave 1 divestitures by asking its corporate services managers to estimate the divestiture savings for their own departments. ORA asserts that asking managers to volunteer for budget cuts is an unreliable way to estimate cost savings resulting from power plant sales. ORA contends that PG&E's estimates are inconsistent with PG&E's February 1997 Phase 2 A&G unbundling study. The purpose of that study was to attribute the incremental electric production costs identified in PG&E's 1996 Cost Unbundling Study to specific power plants. The Phase 2 A&G Unbundling Study attributed $1.3 million of incremental Account 920, 921 and 923 costs to the Wave 1 power plants. In contrast, PG&E's current estimate of Account 920, 921 and 923 savings resulting from Wave 1 divestitures totals $386,000. Finally, ORA contends that PG&E's estimates ignore opportunities for cost savings available to PG&E. ORA contends that PG&E will have ample opportunity to reduce its A&G expenses in 1998 and 1999.

Enron contends that PG&E has not made the requisite showing in support of its proposal to reallocate fixed A&G expenses. In particular, Enron claims, PG&E has not shown that remaining A&G and common and general plant costs are truly fixed, have not been eliminated as the result of divestiture, and are not recoverable through other means.

Discussion

PG&E describes a process of elimination in which direct assignments of A&G costs and common and general plant are made. This process purportedly demonstrates PG&E's residual costs following the Wave 1 divestiture. However, PG&E has done little more than describe an accounting exercise. PG&E has not shown that it considered any opportunities to reduce residual A&G costs, even though this was clearly called for in D.97-08-056. PG&E's survey of its corporate services departments basically asked managers whether divestiture would affect

A&G expenditures of their respective departments. It is neither surprising nor illuminating that managers mostly said no. We are not persuaded that the survey establishes that PG&E’s remaining A&G costs are unavoidable, and thus are fixed and reasonable. In summary, PG&E has failed to demonstrate that the residual costs which its seeks to reallocate are truly fixed, and will continue to exist after the Wave 1 O&M agreements have expired.

In any event, even if PG&E had shown that some of its fixed A&G costs were truly fixed, we would have authorized reallocation of those costs only as of the expiration date of the O&M contracts with the plants’ buyers. This is directed by D.97-08-056, as we recently confirmed in D.99-08-030. Deferring the reallocation in accordance with our previous decisions should prevent the A&G costs attributable to the PG&E employees operating the plants under the O&M contracts from being allocated to distribution. In addition, reallocating fixed A&G expenses upon expiration of the O&M agreements should result in more reliable cost savings estimates because the impact of PG&E’s cost reduction plans will be more clearly understood at that time.

ORA has presented evidence, described above, which casts substantial doubt on PG&E's showing in support of its proposed reallocation of fixed A&G costs related to the Wave 1 divestiture. PG&E has not shown that its proposed reallocation should be adopted. PG&E’s proposal is therefore denied.

If PG&E wants to propose reallocation of any of the fixed A&G costs which remain after the expiration date of the O&M contracts, it should file an application no earlier than six months after the contracts expire. By that time, there will be some post-O&M contract cost data available which show the extent of these fixed A&G costs. Having such data available will help us determine whether reallocation is appropriate. PG&E is authorized to establish a memorandum account to track any fixed A&G costs associated with the Wave 1 plants that it incurs from the time the O&M contracts expire until a final decision in PG&E's application to reallocate these costs is rendered.

11. Revenue Requirement

11.1 Results of Operation (RO)

The calculation of RO tables, never a simple matter, has evolved into a highly complex undertaking in this GRC with the advent of industry restructuring and the unbundling of costs among UCCs. As memorialized in a series of Assigned Commissioner and ALJ rulings, it has been necessary for the advisory staff in our Energy Division to use the resources of modeling experts employed by PG&E for assistance in performing the computer model runs needed to support the proposed and final decisions. We are satisfied that the procedures established in these rulings provided sufficient safeguards to prevent PG&E or any other party from securing any advantage through this modeling process, and are in compliance with Section 1821, *et seq.*

The RO computer modeling conducted in support of the proposed decision took approximately four weeks, requiring the assistance of 10 PG&E modeling experts. Typically five to six PG&E modelers were at the Commission each day when the computer modeling took place. This amounted to more than 750 person-hours of PG&E's and Energy Division's staff time. Additional time was spent preparing the RO tables for the alternate decision.

The purpose of the computer modeling provisions of the Public Code, Stats. 1985, Ch. 1297, Public Utilities Code Sections 1821-1824, is to improve the effectiveness of the Commission's regulatory processes. Section 1(c) of that enactment provides:

> The Public Utilities Commission should have reasonable access to computer programs and models used by public utilities subject to its jurisdiction to improve the quality and efficiency of its regulation.

In view of this statutory language, it is unfortunate that complex computer modeling techniques which are not directly accessible to most parties are required to calculate adopted revenue requirements. As we observed in D.95-12-053, there is a concern that “computer models have reached a level of size and complexity which renders them almost unusable by Commission staff and other parties.” (*Re Pacific Gas and Electric Company* (1995) 63 CPUC2d 414, 425.)

The computer modeling experience in this proceeding clearly reinforces that concern. We note that pursuant to a recent ALJ's ruling in A.99-03-014, Energy Division conducted a workshop to address the computer models that PG&E proposes to use in that proceeding for determining marginal costs, revenue allocation, and rate design. As noted in that ruling, the Commission’s objective is to “have models that we, and all interested parties, can readily use, validate, and adjust to accommodate alternative revenue allocation and rate design options.” (August 24, 1999 ruling of ALJ Gottstein in A.99-03-014.) It makes sense to investigate complex computer models being used in any ratemaking proceeding, and to seek ways to simplify and make those models more accessible to parties, early in a proceeding.

Therefore, within 30 days after any GRC filing made pursuant to our rate case plan for energy utilities, Energy Division should convene a workshop to address RO models to obtain input from parties on how to simplify those models and make them more accessible.

Notwithstanding, the complexity of the computer models used in this proceeding, we are satisfied that the RO tables and adopted revenue requirements set forth in the appendices to this decision, which are based on the RO computer model runs produced by the Energy Division, accurately reflect our determination of the substantive revenue, expense, and capital issues in this GRC decision that affect revenue requirements.

We note that while the RO tables set forth in the comparison exhibit reflect the 9.17% rate of return on rate base authorized by D.97-12-089, the adopted RO tables and revenue requirement calculations incorporate the 8.75% rate of return for 1999 adopted for PG&E in D.99-06-057.

PG&E observes that in calculating the electric RO, it is necessary to allocate costs between retail consumers for whom electric service is under the jurisdiction of the Commission, and resale customers for whom transmission and distribution wheeling service is under the jurisdiction of the FERC. PG&E refers to the process of allocating costs between these two groups as jurisdictional allocation. PG&E states that its proposed jurisdictional allocation methodology has been accepted by both Commissions, and that ORA does not object to it. We adopt PG&E's proposed jurisdictional allocation methodology and the allocated amounts that result from applying this methodology to the adopted Electric Department revenue requirement.

11.2 Attrition

PG&E requests that we approve an Attrition Rate Adjustment (ARA) mechanism for the years 2000 and 2001. The stated purpose is to match changes in authorized revenues with anticipated cost changes during the years between GRC test years, while maintaining a streamlined review and approval process. PG&E proposes the ARA mechanism as an alternative to its proposed PBR mechanism, and requests that either the ARA mechanism or a PBR mechanism be used to determine electric and gas distribution revenue requirements or targets in 2000 and 2001. As shown in the comparison exhibit, the combined gas and electric revenue requirement increases would be $140.3 million in 2000 and $112.5 million in 2001.

PG&E's Proposed ARA mechanism would apply only to the Electric and the Gas Distribution and Customer Services UCCs and Humboldt Nuclear SAFSTOR sub-category of the Electric Generation UCC. PG&E states that the SAFSTOR operations at the Humboldt plant would not be covered by a PBR, and proposes that those costs be changed by the same index as the electric PBR index until decommissioning begins.

Enron and Weil submitted testimony opposing PG&E's ARA proposal. ORA, CFBF, and TURN registered opposition to an ARA mechanism in their briefs. Enron contends that PG&E's ARA proposal guarantees an increase of at least $160 million, that PBR should take its place, and that PG&E has not addressed how an ARA mechanism is affected by restructuring. Weil cites industry restructuring, PBR, and the state of the economy as reasons for rejecting PG&E's ARA proposal.

Discussion

In D.96-01-011, in Edison's 1995 GRC, the Commission considered an ARA mechanism proposal by Edison. In denying an attrition mechanism, the Commission made it clear that there is no inalienable right to an interim increase in rates during a multi-year rate case cycle. The Commission determined that denial of Edison's ARA proposal did not deprive Edison of an opportunity to earn its authorized rate of return, holding that:

> "Neither the constitution nor case law has ever required automatic rate increases between general rate case applications. Attrition year adjustments are a relatively recent innovation and they are more

> recent than the cases cited to by Edison in support of maintaining the current attrition mechanism." (*Id.*, 374.)

More recently, in considering PG&E's 1996 request for a waiver of the three-year rate case plan and increases in base revenues, we observed that attrition mechanisms represent an exception to the general strategy of examining one test year out of every three years and providing the utility an incentive to improve its productivity, and that attrition adjustments were allowed in years when inflation was high. (See *Re Pacific Gas and Electric Company* (1996) 69 CPUC2d 691, 695.)

In the Edison case, the applicant utility was proposing adoption of an ARA mechanism even as it was anticipated that the utility would become subject to PBR regulation during the following three-year GRC cycle. The Commission denied Edison's request after situating the proposal in the context of Edison's proposal to adopt a PBR mechanism that "appear[ed] at least in part a proposal for a different type of attrition mechanism…." (D.96-01-011, 64 PUC2d 241, 374.) The Commission noted that:

> …We have previously stressed the importance of a comprehensive evaluation of Edison's current operations and revenues in this general rate case so we can have a credible benchmark if we choose to utilize it in the future. …[P]ermitting subsequent large attrition increases to occur through the minimal review of an advice letter prior to our completed review of Edison's PBR application could skew this benchmark…. (64 CPUC2d 241, 372-73.)

Since we have concluded that a test year 2002 GRC is necessary for PG&E before PBR can be appropriately and confidently implemented, an ARA mechanism is not precluded by the foregoing decisions. (See Chapter 12.2 below) Giving weight to the concern that there not be a disincentive for efficient management created by an ARA and mindful that an audit of test year 1999 capital additions will give us insight into the forces growing PG&E's ratebase, we will approve PG&E’s proposed attrition mechanism only in part. The attrition year 2000 proposal is denied. The attrition year 2001 proposal is granted to the extent that PG&E may file for an attrition year 2001 adjustment as proposed, with the caveat that the ratebase component may be modified to reflect the results of the audit of 1999 distribution capital spending.

11.3 Major Additions Adjustment Clause (MAAC)

PG&E requests that the Commission approve the establishment of a MAAC to allow for timely cost recovery of the Northeast San Jose Transmission Reinforcement Project. This project is forecast to be operative in 2000, with a capital cost in excess of $68.0 million. PG&E maintains that its request is consistent with Section 1005.5. Pursuant to Section 463 the amounts recorded in the MAAC account would be subject to a reasonableness review by the Commission. PG&E further maintains that its request is consistent the treatment of MAAC requests adopted by the Commission in D.91-04-070.

PG&E states that it followed this precedent in its 1993 GRC. The 1993 GRC decision (D.92-12-057) established a special MAAC called the Air Quality Adjustment Clause (AQAC) for large air quality projects which were expected to be operative in the attrition years 1994 and 1995. PG&E maintains that its proposed MAAC implementation and tariff language in this GRC proceeding are essentially the same as the MAAC approved in D.92-12-057.

PG&E’s Northeast San Jose Transmission Relief Project is a transmission project, and the costs of this project will be recovered through FERC-approved transmission rates. PG&E acknowledges that since transmission-related costs are now under the jurisdiction of the FERC, our approval and review of these costs may no longer be appropriate, and an approved MAAC may no longer be necessary. PG&E requests that we rule on whether MAAC treatment is appropriate for capital additions that are subject to FERC ratemaking treatment.

Weil recommends that we deny PG&E's MAAC request without prejudice. Weil maintains that the request is beyond the scope of this proceeding, notes that transmission rates are subject to FERC jurisdiction, and in any event lacks crucial cost-effectiveness elements.

The impact of rates subject to FERC approval on the bills of California end-use customers, our ability to protect California end-use customers against unjust and unreasonable rates, and the procedures for exercising our traditonal vigilance are issues that are still developing in the various regulatory and judicial venues. We do not intend to limit our authority, or to prematurely join an issue that is not ripe for determination.

Since the Northeast San Jose Transmission Relief Project is a transmission project, and the costs of this project will be presented to California customers through FERC-jurisdictional transmission rates, we find no legal or policy basis for approval of a state-level MAAC for the project. We decline to rule on PG&E's proposal.

12. Other Issues

12.1 Restructuring Implementation Costs (Section 376)

PG&E's GRC request included a request for the recovery in base rates of the estimated incremental costs of certain programs needed to continue implementation of the restructured electric market in 1999. Such costs may be eligible for recovery pursuant to Section 376, but PG&E had waived the special rate treatment available under Section 376 for these costs. Enron, TURN, and CFBF opposed PG&E's request, arguing that restructuring implementation costs that are eligible for recovery under Section 376 should be excluded from consideration in this GRC.

Pursuant to a settlement agreement which was adopted by the Commission in D.99-05-031, PG&E filed a motion on July 2, 1999 to withdraw the portion of its revenue requirement request in this GRC that reflects incremental restructuring-related costs for 1999. PG&E's estimates of these costs are included in the record in this proceeding in Exhibit 418. PG&E states in the motion that it will seek to recover the costs through the Electric Restructuring Costs Account (ERCA) which was approved in D.99-05-031. PG&E estimates that the Electric Department revenue requirement reduction resulting from the motion is approximately $17 million for expense items and $20.6 million for capital expenditures.

In effect, PG&E's motion seeks to implement the position that was advocated by Enron, TURN, and CFBF in this GRC. No responses to the motion were filed. Consistent with D.99-05-031, restructuring implementation costs identified in Exhibit 418 should be removed from this GRC as PG&E's motion proposes. The motion is therefore granted.

12.2 Future GRC

12.2.1 Test Year 2002 GRC

Under the Rate Case Plan, energy utilities are required to file GRCs on a three-year cycle. Like other energy utilities now subject to PBR mechanisms, PG&E has recently proposed adoption of a PBR mechanism for electric and gas distribution which would replace the traditional GRC ratemaking mechanism beginning in January 2000. Since it cannot be foreseen with certainty whether, and when, PG&E will be governed by a distribution PBR mechanism that would supplant the GRC filing requirement, the ALJ asked parties to address in their briefs the question of whether PG&E should be ordered to file a distribution GRC for test year 2002. PG&E, Weil, and CFBF included comments on this topic in their briefs.

PG&E hopes that PBR will be in place, and that a test year 2002 GRC will not be needed. PG&E proposes that if for any reason it appears early in the year 2000 that PBR may not be implemented by January 1, 2002, then the Rate Case Plan should be followed in preparation for a possible 2002 test year GRC. Under that schedule, PG&E would file the Notice of Intent in summer 2000 and the GRC application in the fall of 2000, litigation would proceed in 2001, and the 2002 GRC decision would be issued late in 2001 to become effective January 1, 2002. PG&E points out that there is significant lead time involved in preparing and conducting a GRC. PG&E anticipates that it would begin preparing a 2002 GRC application at the start of 2000 if PBR is not already authorized. PG&E urges the Commission not to make any ruling in this GRC that would impair PG&E's or the Commission's ability to process a 2002 GRC in a timely and orderly fashion in accordance with the Rate Case Plan, if necessary.

Weil in effect agrees with PG&E's recommendation, arguing that reliance on the Rate Case Plan as a default would minimize uncertainty about what will happen if PBR does not succeed. CFBF concurs with the premise that it is good policy to plan for contingencies, but does not believe it is in a position to recommend a clear direction due to uncertainties associated with industry restructuring.

CFBF makes several pertinent observations about anticipated developments in industry restructuring. For example, the nature of direct access and the role of competition are still being determined, and policy determinations in these areas will undoubtedly impact cost recovery for distribution utilities. Nevertheless, we believe that adopting a contingency plan for another GRC is prudent, particularly in view of the long lead times required for processing a GRC. Moreover, requiring the filing of another GRC is consistent with our obligation to ensure that PG&E provides adequate service at just and reasonable rates. We adopt Weil's and CFBF's suggestions about reliance on the Rate Case Plan.

Based on the foregoing, we direct PG&E to file a GRC for test year 2002 in accordance with the Rate Case Plan. We intend to approach this determination with flexibility. However, we intend to achieve alignment of the Rate Case Plan elements so that the test year 2002 numbers can give us a solid cost and operational benchmark for PBR, if that still appears appropriate. To that end, we will direct PG&E to file a 2001 Cost of Capital proceeding in May 2000 so that a timely decision on 2001 return of equity and return on rate base can be achieved. We expect the rate case to incorporate the results of the test year 1999 audit of capital spending, and the results of the one-way balancing account to normalize vegetation management spending, described in Chapter 7. The early collaborative on verifying computer models ordered in Chapter 11.1 above should clarify RO modeling issues. We expect that our admonitions in Chapter 4 will be taken to heart by utility management, and that we will not again be faced at the outset of the case with attempting to understand enormously increased cost levels.

12.2.2 Impact on PG&E's Pending PBR Proceeding

PG&E filed its current application for Performance Based Ratemaking, A.98-11-023, on November 12, 1998. We do not intend to proceed with PBR for PG&E at this time. That proceeding should not move forward to create a structure of financial incentives or financial benchmarks at this time. The application should not be dismissed. Rather, it should be narrowed to provide a basis for adopting specific operating and performance standards applicable to PG&E relating to outage frequency (SAIFI), outage duration (SAIDI) and other reliability and performance measures that correspond to the standards we have already adopted for PG&E's sister utilities. When coupled with the service quality standards we have already adopted, we will have a solid basis for measuring the quality of PG&E's performance, and for linking that to costs under conditions of prudent management in the post-2002 period.

12.3 El Dorado Project Ratemaking Issues

The ratemaking consequences of non-operation of PG&E's El Dorado hydroelectric generation project are at issue in this GRC pursuant to the Commission's order in I.97-11-026 and the April 7, 1998 Scoping ACR in this GRC. By a joint motion filed on April 22, 1998, PG&E and the El Dorado Irrigation District (EID) requested that testimony and hearings in I.97-11-026 be deferred pending the Commission's consideration and resolution of A.98-04-016, in which PG&E seeks approval to sell the El Dorado Project to EID. The moving parties represented that approval of A.98-04-016 would implement a settlement of several significant disputes between PG&E and EID, resolve all of the issues which EID had sought to have addressed in this GRC, and likely reduce the scope of the issues explicitly raised by the order instituting I.97-11-026. The moving parties acknowledged that certain limited issues related to PG&E's El Dorado Project expenses and capital-related costs would remain, including a review of PG&E's authorized O&M expenses and PG&E's capital-related costs from the date I.97-11-026 was issued through January 1, 1998.

The joint motion of PG&E and EID was unopposed and was granted in part by an ALJ's ruling dated June 8, 1998. In a subsequent ruling issued on December 31, 1998, the ALJ asked for comments on procedural alternatives to continued deferral of the El Dorado project issues raised in I.97-11-026 in light of the statement of legislative intent in SB 960 that proceedings be resolved within 18 months. PG&E and EID submitted comments in response.

After considering the motion and the comments filed by PG&E and EID, we are persuaded that going forward to resolve I.97-11-026 before the resolution of A.98-04-016 would likely have resulted in unnecessary, duplicated effort by the parties and the Commission, and could have lead to conflicting outcomes. We therefore affirm the ALJ's rulings which deferred consideration of the issues in I.97-11-026 until A.98-04-016 was resolved. The Commission authorized the sale of the El Dorado Project by D.99-09-066 dated September 16, 1999, and the deferred ratemaking issues can now be resolved. Accordingly, within 21 days of the effective date of this decision, parties may file prehearing conference statements addressing issues remaining to be resolved in I.97-11-026 and the removal of El Dorado Project revenue requirements from the mechanism adopted by D.97-12-096. Thereafter, the assigned ALJ shall set a prehearing conference to identify, and establish a schedule for consideration of, all remaining El Dorado Project issues.

12.4 Section 368(e) Safety and Reliability Funding

As noted earlier, Section 368(e) provided PG&E with an opportunity to increase its base revenues for 1997 and 1998 to enhance electric transmission and distribution system safety and reliability. Funds collected and not expended for this purpose shall be credited against future safety and reliability base revenue requirements. Among other things, D.96-12-077 provided that this test year 1999 GRC is the appropriate forum for reviewing how any unspent incremental revenues for 1997 will be credited against subsequent safety and reliability base revenue requirements as required by Section 368(e)(2). Resolution E-3516 dated

January 21, 1998, which addressed PG&E's proposal for 1998 funding under Section 368(e), similarly provided that this GRC is the appropriate forum to review how excess revenues are credited against subsequent safety and reliability base revenue requirements. Resolution E-3516 also deferred to this GRC consideration of the "issue of PG&E's noncompliance with D.96-12-077 by not maintaining accounting systems, as ordered."

Although the review of the Section 368(e) funding and the compliance issue were placed in this proceeding by prior Commission orders, these matters were not ready for consideration by the time that hearings were set in this GRC. An ALJ's ruling dated December 31, 1998 approved a proposal by PG&E to file a new application to consider these Section 368(e) issues. PG&E's A.99-03-039 was filed pursuant to this ruling. We affirm the transfer of these issues from this GRC to A.99-03-039, and place PG&E on notice that its failure to comply with prior Commissoin orders on accounting for the incremental funds will result in punitive action if we determine in that proceeding that its failure to follow the Commission's orders was willful. In any event, we note that authorized revenue changes for the Electric Department in test year 1999 exclude 1997 and 1998 revenue increments attributable to Section 368(e).

12.5 Adopted Rate Changes

For the electric department, the revenue requirement changes authorized by this decision will not be reflected in rate changes at this time due to the electric rate freeze.

The gas rates adopted herein reflect the adopted GRC revenue requirement, as well as the 1999 true-up of balancing accounts. The total gas revenue requirement is allocated to customer classes according to PG&E's most recent BCAP.

Pursuant to Resolution G-3266 dated September 16, 1999, the adopted gas revenue requirement will be consolidated with other gas revenue requirement revisions. Further adjustments to the gas revenue requirement resulting from the operation of the complete RO model will be subject to balancing account treatment and reflected in rates in the next true-up of balancing accounts, or BCAP, as appropriate.

12.6 Agricultural Rate Information Plan

PG&E has 17 agricultural rate schedules, the majority of which include time-of-use rate components. D.97-12-049 required PG&E to develop a systematic plan for informing new agricultural accounts of their most cost-effective rate schedule and to present the plan in this proceeding. The plan shall include a follow-up procedure to verify that the cheapest rate is being charged once an agricultural account has established a pattern of usage.

PG&E's proposed plan involves software tools designed for use during the initial contact with new agricultural customers and a follow-up analysis tool that will ascertain, as accurately as possible, the cost-effectiveness of the customer's initial rate selections once sufficient data has been recorded. The goal, according to PG&E, is to provide new agricultural customers with information that will enable them to make an informed selection among the various rate options.

PG&E's proposal has four basic components: (1) use of the agricultural rate assignment tool (ARAT) when the new agricultural customer signs up for service; (2) use of the electric rate analysis tool (ERAT) for those new customers for which the ARAT indicates that savings are possible under one or more time-of-use schedules, and the new customer can provide the necessary estimated operating hours and loads; (3) use of an automated follow-up rate analysis using the automated rate analysis program (ARAP) after approximately nine months of usage; and (4) the continued dissemination of information through the use of bill messages and quarterly bill inserts. PG&E maintains that the use of the ARAT and the ERAT, coupled with the information provided by the new agricultural customer, will allow new customers to make informed decisions about which rate schedule to choose.

PG&E believes that the rate information provided to agricultural customers should be based on bundled rates. PG&E contends that it should not be in the position of providing a PG&E estimate of the cost of energy provided by another energy supplier, or by the marketplace under the hourly pricing option. According to PG&E, it does not make sense to increase the role it plays in customers' consideration of whether and how to participate in the deregulated energy marketplace. PG&E also contends that it should not be expected to guarantee that an agricultural customer is on the most cost-effective rate. PG&E notes that actual customer usage patterns may turn out to be different than were anticipated when the rate schedule recommendation was made. Factors beyond the control of the customer and PG&E which cannot be accurately predicted at the time the customer selects an agricultural rate include weather fluctuations, market conditions and pestilence. In particular drought conditions can lead to an increased need for pumping, and harsh winter conditions may require energy usage for frost abatement.

CFBF generally supported the plan, but recommended two relatively minor modifications to it. First, CFBF recommended that the follow-up analysis occur after a full summer season of usage. PG&E proposed that the follow-up analysis take place after the customer has three months of summer and three months of winter usage.[52] CFBF believes that PG&E may be limiting the effectiveness of the follow-up evaluation in an effort to review a new customer's usage as promptly as possible. Second, CFBF proposed that agricultural customers be given an opportunity for a second follow-up analysis.

Discussion

PG&E's plan includes sending quarterly billing inserts to all agricultural customers, reminding them that free rate analyses are available. CFBF accepts these quarterly statements as meeting the CFBF recommendation for a second follow-up analysis. CFBF also agrees that PG&E cannot be expected to guarantee the lowest possible rate for an agricultural customer. Thus, the only disputed issue is whether the follow-up analysis using the ARAP should take place after a full summer season, as CFBF recommends, or after three months of summer usage and three months of winter usage, as PG&E recommends.

PG&E asserts that the ARAP cannot be easily programmed to provide the follow-up analysis on the schedule recommended by CFBF. In addition, according to PG&E, it is not clear that CFBF's approach would be generally beneficial. PG&E notes that it would require customers to wait longer to receive their follow-up analysis. According to PG&E, the ARAP analysis would provide comparable results for most customers, and customers who wish to see the analysis with a full summer of usage data may request an additional ARAP analysis at any time. Thus, PG&E contends, its follow-up schedule should be adopted.

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[52] In PG&E's electric tariffs, summer months are defined as the months of May through October, and winter months are defined as the months of November through April.

CFBF contends that it is important that a full summer season's usage should be used in the follow-up analysis because a variety of agricultural uses may not demand extensive usage during only a portion of the season. CFBF maintains that waiting for a complete summer usage pattern to emerge will provide the most effective assistance to the customer.

We find the reasons listed by PG&E for adopting its follow-up schedule to be persuasive. Since agricultural customers will be able to request additional follow-up analyses at any time, those whose usage pattern for the full summer may differ significantly from any three-month summer period will have an additional opportunity to review their rate schedule selection. PG&E's information to agricultural customers, including its quarterly inserts, should inform customers of this option for additional analysis.

Based on the foregoing, PG&E's proposed agricultural rate information plan responds to the Commission's directive in D.97-12-049 and should be adopted without modification. We concur with PG&E's contentions that it cannot reasonably be expected to guarantee that a customer is taking service on the most cost-effective rate schedule, and that the purpose of this program is to allow new agricultural customers to make informed decisions in choosing their agricultural rate schedules.

As part of its compliance advice letter filing in this GRC, PG&E shall file tariff language which implements the agricultural rate schedule information plan adopted herein, as set forth in Exhibit 13. PG&E points out that the analytical tools used to implement the plan will change over time, as will its agricultural rate schedule offerings. We recognize the need for flexibility in the plan adopted today, and that from time to time PG&E may need to file appropriate tariff revisions to modify the plan.

12.7 Profit Center Framework

During its investigations of PG&E's GRC application, ORA came to the position that certain activities cannot be classified as either fully monopoly or fully competitive. ORA determined that such activities should be classified as potentially competitive services. Examples of what ORA considers to be potentially competitive services are the CIS and certain IT projects, including the Call Center Enhancements.

With respect to these potentially competitive services, ORA is concerned that PG&E is installing excess capacity beyond that needed to support monopoly ratepayers. ORA is also concerned that by taking such actions, PG&E is asking ratepayers to subsidize competitive activities which are beyond the scope of core utility services.

To mitigate these concerns, ORA proposes a "profit center framework" as a means of regulating potentially competitive services. As explained by ORA witness Selwyn of Economics and Technology, Inc., the profit center proposal draws from concepts associated with the New Regulatory Framework for telecommunication utilities. ORA policy witness Schmid explains the proposal as follows:

> "The proposed profit center treatment would in effect impute to these 'Potentially Competitive' service categories outside sources of revenue in amounts minimally sufficient to recover outlays not required to support monopoly function, thereby avoiding ratepayer subsidization of PG&E's competitive ventures. Through the imputation process, the entire amount of 1999 expense levels and capital additions associated with the provision of revenue cycle services would be included in the rate base, but only that portion of PG&E's outlay legitimately required to support monopoly [utility distribution company (UDC)] services would effectively be included in the revenue requirements to be funded by monopoly ratepayers..." (Exhibit 71, p. 7.)

* * *

> "...ORA recommends that Phase II of this GRC be used to pursue the actual unbundling of these services into profit centers, as discussed above, thus placing PG&E's shareholders at risk for the portion of these costs that represent investments in excess of levels required to service PG&E's ratepayers. In light of the changes occurring in the electric and gas industries, ORA supports full unbundling of PG&E's services. ORA proposes that Phase II of the GRC also be used to apportion PG&E's costs between the following three categories: Monopoly UDC Services; Potentially Competitive Services, such as revenue cycle services; and Fully Competitive Services." (*Id.*, p. 8.)

* * *

> "Under this approach and for those services that are not fully competitive, costs and revenues in the Monopoly and Potentially Competitive Service categories would be considered in setting PG&E's revenue requirement in this GRC as well as in Phase II. Costs that are exclusively attributable to one or the other of these two categories would be assigned solely to that category, whereas costs that are shared by both categories would be recovered through revenue from both categories." (*Id.*)

In its opening brief, ORA stated its agreement that the profit center proposal can be summarized as follows:

1. PG&E should separately identify the costs of potentially competitive services.
2. PG&E should record the revenues from such services above the line.
3. The Commission should reduce PG&E's revenue requirement for such services by imputing competitive revenues.
4. If PG&E subsequently spins or sells the potentially competitive services, or moves them below the line, ratepayers should participate in the appreciation of value.

PG&E objects to ORA's profit center proposal for several reasons. PG&E takes the position that the Commission should not needlessly complicate this case by considering proposals for competition and unbundling. PG&E finds the profit center framework to be such a proposal, and contends that it is superfluous to the determination of the GRC revenue requirement. Moreover, PG&E contends, it does not take into consideration outstanding Commission proceedings and precedents with which it may very well conflict, such as those associated with the affiliate transactions rules and new products and services, and those associated with revenue cycle and other direct access services.

Discussion

The *Assigned Commissioner''s Ruling Pursuant to Rule 6(d)* (Scoping ACR) dated April 7, 1998 provided guidance and direction on the scope of this proceeding. Among other things, it provided that this is not a generic unbundling policy proceeding. Instead, the overarching objective of this GRC proceeding is to set the revenue requirement for distribution and customer service functions.

The April 7 ruling acknowledged "the need for setting a revenue requirement which does not reflect subsidization of competitive activities." (Scoping ACR, p. 9.) Arguably, this provides the basis for consideration of the profit center framework. However, having reviewed the profit center proposal and the underlying support offered by ORA, we are persuaded that it does not meet the Scoping ACR's standard for inclusion in this GRC.[53] As PG&E points

53 In a motion filed on June 22, 1998, PG&E sought to have stricken those portions of ORA's reports and prepared testimony in which ORA recommended adoption of the profit center framework. The assigned ALJ denied the motion, having concluded that ORA was entitled to demonstrate that its profit center proposal is necessary for determining a reasonable revenue requirement for utility services which may become competitive. We affirm the ruling.

out, the profit center approach is not used by ORA to develop its own revenue requirement recommendation in this GRC. Despite having had an opportunity to do so, ORA has not demonstrated that the profit center framework is necessary for determining a reasonable revenue requirement for distribution services, including potentially competitive services as defined by ORA. Accordingly, irrespective of the merits of the profit center concept as a tool for dealing with the concerns raised by ORA, it is beyond the scope of this GRC and should be denied without prejudice.

We wish to emphasize our agreement with the premises underlying ORA's proposal. In particular, captive utility ratepayers should not be asked to subsidize the acquisition of assets, or the performance of activities, that are unrelated to the utility mission of providing basic utility services, and that may further PG&E's or its parent's objectives in competitive arenas. We are confident that our decision today on PG&E's revenue requirement request does not provide for any such subsidy. Thus, the need for the profit center framework has not been demonstrated at this time.

In installing the capacity needed to serve monopoly ratepayers, it is possible that PG&E creates the ability to provide ratepayer-funded services on behalf of others. However, this alone does not demonstrate that PG&E has installed excess capacity if the asset in question produces a joint product. The example of the new billing center is illustrative. Assuming that the billing center is appropriately sized to serve distribution ratepayers, even though the facility may be available for a third shift, it may still be possible for PG&E to provide billing services to others with no degradation to the service provided to ratepayers. If this is the case, the creation of an asset required for utility service has produced the joint products of utility billing and non-utility billing.

Our primary interest is not to prevent the economically efficient use of assets that produce joint products, or to deprive the public of economies of scope, scale and integration not otherwise available to them. We seek to ensure that ratepayers pay no more than what is required to provide utility service, and that revenues derived from ratepayer-funded assets are reasonably apportioned among ratepayers and shareholders. ORA has not shown that existing regulatory treatment of other operating revenues, affiliate transactions, and non-tariffed services is inadequate for the purpose of meeting our objectives.

Findings of Fact

1. As in any GRC, our primary task in this GRC is to forecast PG&E's reasonable revenue requirements for the test period, i.e., the amounts of revenues needed by PG&E to provide adequate public utility service and earn a reasonable rate of return for 1999 under conditions of prudent management.
2. PG&E has represented that it is seeking revenue requirement increases of $445 million for the Electric Department and $377 million for the Gas Department. These increases are 20.4% and 46.3%, respectively, of what PG&E has shown as its present GRC revenues.
3. When the safety and reliability funding authorized by Section 368(e) is excluded, PG&E is seeking an increase of nearly $686 million, or 35.3%, for the Electric Department. When the effect of PG&E’s motion to withdraw restructuring costs is included, the requested increase is 33.3%.
4. PG&E's requested increases of more than 33% and 46%, respectively, above the base electric and gas revenue amounts adopted in the last GRC constitute grounds to carefully scrutinize each aspect of PG&E's showing in this GRC.

5. As a matter of policy, we seek to avoid approving an excessive revenue requirement for electric distribution service that would unnecessarily diminish and delay the anticipated rate reduction benefit of electric industry restructuring.

6. The public participation record shows that gas bill increases as large as those proposed by PG&E would cause hardships for residential and commercial ratepayers.

7. Allowing PG&E to collect and retain any more revenue than is necessary for it to provide safe and reliable utility service, and to earn a reasonable rate of return on investments needed to provide that service, would lead to a reduction in economic welfare.

8. PG&E has a corporate goal of realizing the benefits of AB 1890 by, among other things, ensuring that the electric rate freeze continues through 2001 while also ensuring that stranded costs are recovered in full.

9. PG&E's authorized electric revenue requirement at a level consistent with maintenance of adequate service and a fair return may preserve and foster competition in California's electric services market in the post-transition period.

10. The super A-J effect is a credible theory for describing the incentives facing PG&E, and may, at least in part, explain the increased spending that underlies PG&E's request in this GRC.

11. Most electric customers prefer improved reliability, but for many that preference persists only when cost is not a consideration.

12. No electric customers want a degraded quality of electric distribution service.

13. Customers for whom high levels of reliability is important <u>may</u> have alternatives to obtaining higher reliability from the utility system.

14. PG&E has not shown that rising customer service expectations justify significant expenditures for achieving reliability improvements.

15. PG&E has been providing adequate service in the past three years.

16. It is our policy that any significant degradation in PG&E's service quality is unacceptable, and that PG&E's authorized revenue requirements should be sufficient to cover the costs of continuing the level of service achieved by PG&E in the past three years.

17. PG&E has moderated its commitment to cost cutting and rate reduction since its previous GRC with an increased emphasis on reliability and customer service.

18. PG&E's gas and electric revenue requirement requests in the original application were consistent with, and even below, what was predicted by total factor productivity analysis.

19. PG&E has not proved through its aggregate cost comparison studies that its costs in 1996 were representative of the more efficient utility firms.

20. When reasonable adjustments to PG&E's aggregate cost comparison studies are made, the studies support a conclusion that PG&E's cost performance in 1996 was below average.

21. ORA's DEA analysis supports the conclusion that PG&E was not among the efficient utility operators in 1996.

22. The comparison exhibit does not accurately reflect ORA's positions in all respects, but ORA has had an opportunity to clarify its positions on matters represented in the comparison exhibit, and to advise us of its positions with reference to the record.

23. While there are significant impediments to completion of distribution bypass projects, competition and CTC exemptions provide an incentive for bypass to occur.

24. The midpoint of the distribution bypass forecasts recommended by PG&E and Weil is a more likely and, therefore, more reasonable forecast than either party's forecast.

25. FEA has not demonstrated that its proposed adjustments to electric revenues are required in connection with the final PG&E position as set forth in the comparison exhibit.

26. Generation production expenses are at issue in this GRC for the purpose of common cost allocation and to comply with D.97-12-096, which established the alternative revenue requirement mechanism for hydroelectric and geothermal generation units.

27. In view of evidence that Humboldt SAFSTOR O&M expenses increased in 1997, PG&E's forecast of $4.148 million is reasonable.

28. PG&E has not adequately supported an increase in regulatory fees to operate power plants.

29. PG&E's forecast of project-related expenses incurred pursuant to power purchase contracts with irrigation districts should be reduced by $4.617 million to reflect a 3.5% escalation factor and the actual contract for the Tri-Dam Project.

30. PG&E has not provided adequate justification for its proposed incremental expense of $4.2 million for the cost of PX sales.

31. PG&E has not provided adequate justification for its proposed incremental expense of $2.8 million for gas and electric supply functions.

32. PG&E does not bid demand into the PX on behalf of direct access customers, and if PG&E collects costs for this activity from all distribution customers, direct access customers will pay twice for the same service.

33. Pending divestiture or other market valuation of PG&E's hydroelectric facilities, allowing PG&E's forecast of costs for flood studies will promote dam safety.

34. It is probable that PG&E will incur some expenses for FERC hydroelectric plant operating license conditions in the test year, and it is therefore reasonable to authorize $5.555 million in expenses incurred in fulfilling license conditions.

35. For as long as PG&E owns and operates hydroelectric assets, it is reasonable and prudent to include a forecast of ongoing maintenance requirements in the revenue requirement for those assets.

36. PG&E's forecast for hydroelectric generation expenses for 1999 does not reflect storm damage repair expenses, so it is not necessary to adjust its 1999 forecast for insurance proceeds related to storm damage to its hydroelectric facilities that occurred in the winter of 1996-1997.

37. The mobile synchronous condenser installed by PG&E at its FMC Substation adds generating capacity and is properly classified as a generating plant.

38. For almost a decade, throughout a series of GRC cycles, PG&E consistently underspent ever-decreasing maintenance budgets, then increased such spending dramatically in 1995 and 1996.

39. PG&E's electric distribution system maintenance practices were inadequate in several important respects for a period of several years prior to 1995, but PG&E began correcting this situation at about the time of the storms of early 1995.

40. Deferred and deficient maintenance practices can have the effect of requiring increased expenditures in the future even though they may save money in the short run.

41. The physical condition of PG&E's electrical distribution system at the beginning of 1996, and the readiness of PG&E's management and work force to perform maintenance activities were not the same as they would have been had PG&E spent more on maintenance, and spent more effectively, in the preceding

years. Thus, some spending in 1996 is attributable to past inadequate maintenance by PG&E and may not be representative of normal spending levels.

42. PG&E's reduced electric distribution maintenance spending in the late 1980's and early 1990's was, at least in part, associated with the performance of fewer maintenance activities than PG&E should have performed.

43. An unquantified portion of PG&E's increased electric distribution system maintenance spending in 1996 can be attributed to earlier deficient or deferred maintenance, for which ratepayers should not be responsible; and another unquantified portion of the increased spending was a reasonable and appropriate response by PG&E for which PG&E should be recompensed by ratepayers.

44. PG&E's forecast change in tree trimming and routine tree removal activity, from an average rate of 845,000 units per year during the period 1987 to 1994 to 2.1 million units per year in 1999, warrants careful scrutiny for purposes of setting PG&E's rates in 1999 and beyond.

45. PG&E's new tree inventory data base is the primary basis for the number of trims forecast by PG&E.

46. PG&E's new tree inventory data base should enable more reliable and consistent tree counts in the future.

47. Dividing the number of trees by an overall average trim cycle to yield an estimate of required annual trims does not imply or require that each tree be trimmed on the same cycle irrespective of each tree's growth rate.

48. Using a weighted average trim cycle that takes into account the specific trim frequencies of trees identified in the data base is reasonable.

49. A test year forecast of 1.841 trims is reasonable.

50. PG&E's unit cost estimate for tree trimming reflects the results of competitive bidding at a time of higher demand and use of out-of-state crews associated with accelerated tree trimming efforts.

51. The historical average trimming / removal cost of $51 (in 1996 dollars) per unit is a reasonable estimate for forecasting test-year tree trimming expenses.

52. PG&E's experience with the consequences of its past tree trimming practices should act as an incentive for it to avoid inappropriate underspending on this activity.

53. Certain distribution poles in designated fire areas (subject poles) have equipment or connectors that could potentially ignite vegetation at the base of the pole.

54. PG&E's forecast of the costs of vegetation clearing at subject poles reflects updated data from the new tree inventory data base.

55. PG&E's past inadequate tree trimming practices may contribute to the need for the proposed supplemental tree trimming program.

56. For electric distribution operations accounts, the fact that the parties' forecasts of total operations expenses fall within a narrow range reveals that relatively little forecasting difference is attributable to the forecasting method used. This appears to reflect relative stability in the level of expenditures on operations.

57. Although none of the electric distribution maintenance accounts meet the criteria from D.89-12-057 that would indicate the use of a single base year for test-year forecasting purposes, the use of a four- or five-year average that includes two years when PG&E was almost certainly spending less than it reasonably should have on electric distribution maintenance will yield an unreliable estimate of PG&E's legitimate spending needs in 1999.

58. For electric distribution maintenance expenses other than vegetation management, the use of 1996 recorded / adjusted expenditures is likely to yield more accurate forecasts of reasonable expenditures for 1999 than averaging.

59. When vegetation management expenses are isolated, differences in the parties' forecasts of total maintenance expenses attributable to the forecast method used are less significant.

60. CFBF's electric distribution O&M forecasting approach of disallowing previously-authorized but unspent amounts would hold utilities to a standard of having to expend all authorized amounts.

61. There is no evidence that PG&E is out of compliance with Tariff Rule 2, or that PG&E is systematically serving electric distribution customers at unnecessarily high service voltage levels.

62. Although a new requirement in GO 165, adopted in March 1997 by D.97-03-070, requires PG&E to conduct annual and biennial patrols of underground facilities, PG&E has not justified the costs of annual inspections in rural areas where the new standards require inspections half as often, and has not justified basing the daily cost of inspections on overtime rates of pay.

63. Whether or not Pacific Bell shares in the costs of testing and treating jointly owned poles, PG&E has not shown that it is reasonable to charge electric ratepayers $3.2 million for its supplemental pole test-and-treat maintenance program.

64. After adopting PG&E’s forecasting method for underground maintenance, it is not necessary to adopt PG&E’s additional forecast adjustment of $5,254,000 in Account 594.

65. No party contests the validity or accuracy of PG&E's forecast of the capital-related revenue requirements of $277,890,000 for hydroelectric generation and $73,817,000 for geothermal generation.

66. The risks associated with transition cost recovery do not provide PG&E with adequate incentive to reduce capital expenditures under recorded cost ratemaking for its hydroelectric facilities.

67. ORA's recommended capital adjustments for structurally overloaded wood transmission and distribution poles reflect PG&E's determination that it caused the structural overloading 20% of the time, and that telecommunications utilities, primarily Pacific Bell, are otherwise responsible for the overloading.

68. PG&E's requested gross electric distribution plant additions for 1999 are twice the amount authorized in the last GRC for 1996, and its requested net plant additions for each of the years 1997 through 1999 are nearly twice those recorded between 1993 and 1996.

69. A showing by PG&E that its electric distribution capital forecast reflects the collective judgment of those who are most knowledgeable of the system, and that reliability and responsiveness will be improved under its spending plan, is sufficient to justify the forecast; the economic justification for the proposed spending should also be considered.

70. Improved electric distribution system reliability is an important driver of the increased capital spending by PG&E in this GRC cycle.

71. The operating and engineering experts and managers who took part in PG&E's electric distribution capital forecast effort did not conduct cost-effectiveness analyses, value-of-service studies, or any other study of the willingness of ratepayers to pay for improved reliability.

72. It is reasonable to expect that PG&E needs to spend more during this GRC cycle in response to customer and load growth than it did in the previous GRC cycle, but there are also strong indications that PG&E has overstated the impact of economic recovery on its growth-related investment needs.

73. TURN's regression analysis of 20 years of data supports the conclusion that PG&E's requested capital spending for the 1997-1999 time period is greater than what would be predicted from PG&E's historical capital spending patterns, taking into account customer growth and the size of the system.

74. It is prudent for PG&E to plan its distribution system in this GRC cycle with the assumption that the northern California economy might not be substantially impacted by the Asian economic situation in respects that are relevant to electric distribution system growth.

75. PG&E spent less than $1 million for electric distribution emergency capacity projects in the nine years preceding 1997, spent $37 million on such projects in 1997 alone, and seeks approval for $55 million in emergency capital additions for the three years at issue in this GRC.

76. This increased level of spending on distribution emergency capacity projects should be closely evaluated to determine its benefits for the public.

77. In addition to the foregoing findings, the following facts constitute additional reasons for closely monitoring PG&E's proposed level of electric distribution capital spending: (a) PG&E installed 1,300 MW of capacity in 1997, more than is explained by the rate of customer growth at that time; (b) peak loads in a minority of DPAs are well below capacity, and PG&E has a history of overestimating capacity needs in a majority of DPA forecasts; (c) PG&E's use of temperature adjustments in load forecasts represents a reliability improvement which may be desirable but has not been shown to be cost-effective; (d) PG&E has made temperature adjustments based on statistical methods which lack testing for statistical significance; (e) PG&E's trend line adjustments create an upward bias in load forecasts, and in certain cases the adjustments were applied incorrectly; (f) PG&E included block load additions in trend line forecasts, creating an upward bias towards capacity additions; (g) load transfers among

DPAs were not fully accounted for, creating doubt as to the accuracy of some DPA forecasts; (h) PG&E may not have considered alternatives to expensive capacity additions such as power factor corrections, even though its distribution planning guide provides for such consideration; (i) there was a likelihood that PG&E would spend $140 million less on distribution investments in 1998 than it has requested in this GRC, and that it would spend up to $90 million less than its request for 1999; and (j) PG&E's claim that it conducted a comprehensive bottoms up / top down forecasting effort appears to be overstated with respect to projects under $1 million, yet those projects account for most of the estimated distribution capital spending.

78. PG&E's forecast of electric distribution capital spending was developed under a corporate policy of making significant improvements in the reliability of the electric distribution system, at a time when Section 368(e) funds were available, when PBR regulation loomed near, and when it was becoming more apparent that competitive forces may be making inroads into the distribution services industry.

79. ORA's regression model for electric distribution system capital additions is not sufficiently robust or technically sound to stand as the sole basis for forecasting PG&E's reasonable capital spending needs for this GRC, but can be relied upon as additional evidence that PG&E's capital spending beginning in 1997 is substantially greater than what would be predicted on the basis of the historical spending, taking into account expenditure drivers such as customer growth.

80. TURN's alternative electric distribution capital spending recommendation considers detailed, project-specific expenditures by implicitly accepting PG&E's detailed analysis as the starting point for its own underlying analysis, and is

based on detailed, project-specific analyses of the methods and procedures used by PG&E in developing its forecast.

81. TURN witness Marcus is qualified to review PG&E's electric distribution system capital showing, conduct discovery, analyze data given to him by PG&E and data available from other sources, make judgments about the reasonableness of PG&E's proposed and forecast distribution capital spending, and make recommendations to the Commission based on such analysis and judgment.

82. Enron's five-year averaging method for forecasting electric distribution net capital additions gives insufficient weight to key drivers of capital expenditures that are likely to be at work in the period covered in this GRC cycle, and is therefore less reliable than the regression analyses used by other parties.

83. FEA has not demonstrated that its proposed adjustments to gas revenues are required in connection with the final PG&E position as set forth in the comparison exhibit.

84. PG&E is obligated to provide gas procurement services to core and core subscription customers at tariffed rates.

85. PG&E's proposal for including gas procurement costs in revenue requirements is consistent with our BCAP ratesetting process, in which the procurements costs are subtracted from the distribution revenue requirement, and included in procurement rates as a brokerage fee.

86. Gas R&D activities that PG&E has included in this GRC, including distribution-related R&D, are consistent with the promotion of efficiency and safety for ongoing regulated operations.

87. Enron has not demonstrated that PG&E's gas R&D request harms current or future competition.

88. PG&E provided erroneous information to the Commission in the previous GRC by failing to disclose an accounting change that treated as capital costs

certain GPRP costs that had previously been expensed. As a result, the Commission adopted a forecast of $3 million in GPRP expenses even though the underlying costs were being capitalized.

89. PG&E benefited at ratepayer expense from providing misleading information about GPRP costs to the Commission in the previous GRC.

90. PG&E has removed disputed amounts for test-year GPRP expenses from its GRC request.

91. PG&E indicated in a data response that it expected to conduct carbon monoxide tests in 33,500 homes in 1998 at a cost of $1.8 million.

92. A moderate expansion of carbon monoxide testing in 1999 is reasonable.

93. ORA has not shown that PG&E's gas system maintenance practices prior to 1996 were as problematic in scope or degree as those of the electric system.

94. With respect to compliance with the established standards, the Arthur Anderson report noted that the preventative maintenance process for the gas distribution system was generally well managed, and that PG&E divisions were in compliance.

95. Although the amount was not quantified, an incremental amount of remedial gas system maintenance is reflected in 1996 recorded expenses relied upon by PG&E in its expense forecast for the gas distribution system.

96. PG&E's requested gas distribution system maintenance expense of $50.2 million exceeds the 1996 adopted maintenance expense by nearly 44%, and the total increase requested in gas distribution O&M expenses is $22.2 million, or more than 18%.

97. The history of gas distribution operating Account 875 is consistent with our guidelines for the application of the averaging forecasting method.

98. There were significant fluctuations in gas distribution maintenance expenses from 1993 to 1996, which favors the use of averaging under our established forecasting guidelines.

99. Because an increment of deferred gas distribution maintenance expense is reflected in the 1996 recorded year that PG&E uses as the starting point for its maintenance expense forecast, an average of maintenance expenses incurred over a period of years is more likely to predict actual needs going forward.

100. Unlike PG&E's past electric distribution maintenance expenses, where we found that it would be inappropriate to use an average based on several years during which PG&E spent less than reasonable amounts on maintenance, we have not found that PG&E's gas system maintenance expenditures during the 1993 to 1996 period reflect inadequate or insufficient practices to any substantial degree.

101. Growth in the gas distribution system has been a minimal 1.0% per year since 1993 as measured by the increases in miles of main or in number of services. Moreover, at least in part, additional gas distribution maintenance costs attributable to growth should be offset by operating efficiencies and improved productivity.

102. Averaging as the appropriate forecasting method for gas distribution maintenance costs.

103. The claim that increased construction activity increased both the number of Mark and Locate requests and the number of dig-ins causing damage to PG&E’s gas distribution system does not refute the use of averaging to forecast maintenance requests.

104. Through the BCAP process, customer access revenue requirements for transmission level end use customers, including the costs of the UEG gas meters,

are removed from the distribution revenue requirements to assure that distribution level customers do not pay for them.

105. All parties are in agreement that UEG meters should be included in transmission rates under the Gas Accord.

106. PG&E's proposed capital spending of $78 million for the distribution component of the GPRP is 30% greater than the ten-year historical average of $60 million per year (in 1998 dollars) for the program. In addition to the $78 million spending level that PG&E seeks for the distribution component of the GPRP, PG&E proposes transmission pipeline replacement expenditures of $17.7 million in 1998 and $15.2 million in 1999, which indicates the total increase is much greater on a program basis.

107. The GPRP has been and remains on schedule, although PG&E needs to replace an additional 20% of the distribution mileage each year to complete the distribution component on time.

108. PG&E publicly touted the benefits of Cured In Place Pipe liners, internal correspondence shows that PG&E approved two demonstration projects using this technology with the expectation of system-wide implementation in 1997, and a March 1998 press release stated that PG&E had completed an exhaustive five-year testing and development program for this technology.

109. PG&E consistently spent less than authorized amounts on the GPRP throughout its existence, and as recently as 1998 was on track to spend up to 25% less than the $78 million estimate it advances in this GRC.

110. Removal of $1.314 million from the gas distribution plant balance will stem continued overpayments by the amount of 1994-95 GPRP costs that were treated as capital investments even as they continued to be treated as expenses.

111. It is reasonable to infer that PG&E incorrectly capitalized some GPRP expenses from May of 1996 through the end of 1997, and to use an estimate of

$2.4 million for that 20-month period as the amount by which to reduce operating plant.

112. PG&E's approach to estimating gas distribution capital spending needs for the Purchase Meters MWC is based on the current meter inventory level as well as a forecast of the meters required for new customer connects, the scheduled meter change program, and miscellaneous meter changes, and is more likely than ORA's approach to yield a reasonable estimate of those needs.

113. PG&E's 1999 gas distribution new business capital expenditure forecast does not reflect productivity improvements that PG&E itself expects to realize.

114. New line extension rules may have the effect of lowering the amount of new business activity included in gas distribution rate base.

115. For gas distribution capital expenditures, an average based on historical spending gives insufficient weight to current conditions that are reflected in PG&E's budgeting and planning process.

116. The failure of PG&E's gas resource plan to comprehensively evaluate alternatives to planned infrastructure investments such as energy efficiency and electric supply, and to assess the value-of-service relationship between core gas and electric customers, are deficiencies which should be remedied to the extent we rely upon such plans in the future.

117. The 1-in-90 year gas resource planning criterion is a higher standard than that used or proposed by other utilities, but lowering the standard has not been shown to be cost-effective.

118. Contested issues pertaining to Other Operating Revenues have been resolved by the parties, as reflected in the comparison exhibit.

119. PG&E's total compensation study conforms to professional practices for analysis of total compensation, and substantially complies with the Commission's 1996 GRC decision regarding the use of independent experts.

120. PG&E's compensation practices result in its paying its employees 7.23% more on a weighted average basis than the compensation calculated for comparable firms.

121. A range of error around the total compensation survey average is to be expected with any survey methodology, and it is necessary to make an informed judgment about the maximum departure from the mean that still qualifies as the market level.

122. Industry restructuring may lead to increased competition for workers, but increased competitive pressures could also lead to increased effort by employers to control costs.

123. Allowing additional rounds of testimony and deferring hearing on A&G issues mitigated the procedural disadvantage faced by ORA and other parties that addressed PG&E's showing on A&G expenses, but their ability to fairly address PG&E's A&G showing may have been compromised.

124. PG&E's analysis in support of its proposed incremental adjustments in Accounts 920, 921, and 922 was error-prone and unreliable.

125. PG&E did not conduct a meaningful analysis of the impact of the Smart Spending Program and the Overhead Optimization study on its GRC expense estimates.

126. There is no compelling evidence for a change in our current practice of allowing 50% recovery of targeted PIP incentives from ratepayers.

127. Although PG&E paid out just 72.5% of its target PIP payout during the five years ending with 1996, it paid out nearly 100% of targeted costs over a ten-year period.

128. There is a linkage between employee headcount and severance pay even if every single instance of a severance payout is not associated with the elimination of a position.

129. Even if PG&E's forecast of $8.997 million in severance payouts is correct, PG&E has not demonstrated that it made appropriate corresponding downward adjustments to its GRC request to reflect the reduced head count associated with the severance pay it seeks to recover. Thus, it is neither reasonable nor fair to include severance pay expenses incurred by PG&E in 1999 revenue requirements.

130. It appears likely that, despite PG&E's stated agreement with the principle that incremental allocations to Diablo Canyon are inappropriate, its recommendations reflect such an approach in some cases.

131. Diablo Canyon receives greater benefits from the regulatory relations, rates, and law departments than those reflected in the Effort Study.

132. The use of salary weighting for Diablo Canyon allocation was adopted in the last GRC to counter the assumption that an hour spent by an executive is valued the same as an hour of a junior clerical worker, and PG&E has not demonstrated why this allocation method should not be applied in this GRC.

133. TURN's recommended Diablo Canyon salary weighting factor of 3.53% reflects the expert opinion of witness Marcus that the use of 1996 data is reasonable as a proxy value in the absence of more current information.

134. ORA has not shown that the Effort Study results are inappropriate for Line 401 allocations.

135. PG&E's Effort Study generally provides an adequate basis for allocations of A&G expenses to PG&E's affiliates and the holding company, except where ORA has shown significant problems with PG&E's departmental allocations.

136. Because ORA has not shown that its attempt to capture SAP development costs through its proposed allocation is justified, PG&E's position on the BSID allocation to affiliates and the holding company is better supported than ORA's allocation.

137. PG&E's corporate accounting headcount adjustment is not adequately supported, whereas ORA's allocation for the corporate accounting department is based on employee-by-employee reviews of department activities.

138. The internal communications department does not provide audio-visual support to affiliates, PG&E Week is a utility product, and the intranet is utility-only, separated from the affiliates by a firewall.

139. Costs associated with lobbying incurred by the political resources department account for 40% of the costs of this department, and should be excluded from recovery in this GRC. PG&E's 3.55% allocation should be applied to the remaining 60% of the department's costs.

140. Even though PG&E has only one shareholder, the financial benefits of equity financing are secured for the utility by the holding company. However, the benefits are diminished by the utility's lack of direct access to equity markets, which could potentially impair the utility’s ability to issue new securities on reasonable terms.

141. For allocating shareholder services costs to affiliates and the holding company, it is reasonable to adopt the midpoint between PG&E's recommendation of 28% and ORA's recommendation of an 84% allocation.

142. The law department can reasonably be expected to provide more than 126 hours of attorney services to affiliates other than PGT, even after accounting for the 1998 transfer of seven attorneys out of the department.

143. PG&E's establishment of a holding company which oversees affiliates that engage in non-regulated activities was largely, if not entirely, the consequence of management decisions that benefit shareholders.

144. PG&E has not demonstrated why the incremental costs of its holding company structure should be charged to its utility ratepayers as a result of the

Pacific Enterprises / Enova Corporation merger decision (D.98-03-073, mimeo., Attachment B, p. 17.)

145. It is reasonable to require that incremental costs resulting from the formation of PG&E Corporation that provide no demonstrable benefit to the utility be allocated to the utility's affiliates.

146. PG&E was generally unable to adequately document how the Effort Study accounts for services that PG&E Corporation was expected to provide to affiliates in 1998 and 1999.

147. As the senior executive official of the corporate enterprise, the holding company CEO uniquely provides overall vision and leadership through active involvement in the operations of subsidiaries, and represents a tangible benefit to subsidiaries including PG&E.

148. PG&E has not demonstrated that its own law department needs to purchase legal oversight services from PG&E Corporation, nor has it demonstrated how the oversight services benefit PG&E.

149. PG&E has not demonstrated that PG&E will require more than the 3,744 hours of holding company law department services estimated by ORA.

150. PG&E has not demonstrated why PG&E’s own CFO is incapable of providing access to and representation before the financial community, strategic advice on acquisitions, mergers and divestitures, and expertise on debt finance and capital structure issues without assistance from PG&E Corporation.

151. PG&E did not produce written work products prepared by the holding company's business planning department on behalf of PG&E or otherwise demonstrate the value of this PCC to PG&E.

152. The functions of the administration and external relations department consist of general corporate oversight activities that benefit the holding company.

153. ORA's recommendation for the holding company's corporate secretary does not account for the fact that in the holding company structure, the utility subsidiary derives the benefit of access to equity markets from the parent company.

154. Because the benefits of access to equity markets are offset by the reduction in financial flexibility on the part of the utility, PG&E's proposed allocation reflects the inappropriate assignment of generation divestiture costs to this GRC, and there is general concern regarding the potential duplication of the efforts of senior officers of the utility and the parent holding company, ORA's 14.25% allocation for the corporate secretary is reasonable.

155. ORA has not demonstrated that PG&E's accounting treatment of rental expenses contravenes FERC accounting requirements or generally accepted accounting principles.

156. PG&E has not justified an increase in its estimated rental expense from $3.2 million to $4.2 million, and ORA has raised significant questions regarding the reasonableness of the original $3.2 million estimate.

157. The recorded 1997 rent expense was $1.225 million, and Account 921 should include no more than this amount in rent expense.

158. An incremental approach should be used for allocations of A&G expenses to construction, and the criterion for determining incremental costs is the extent to which a department's activities would be reduced in the absence of ongoing construction activities.

159. Although ORA's use of a labor-based allocator of 26.7% for allocations to construction for several PCCs may not be fully consistent with accounting guidelines, it is more reliable than PG&E's claims of no incremental costs. for some departments.

160. In the absence of PG&E's ongoing construction program, the volume of accounting transactions processed by the BSID would be significantly lower, staffing requirements for the SAP help desk and training activities performed by the BSID Change Management Section would be reduced, and transactions volumes processed by PG&E's general ledger, capital accounting, accounts payable, materials management, and Non-Energy Billing System / Mainline Extension systems would be reduced.

161. ORA has not shown why the 1990 Effort Study produces more reliable information regarding the Data Information Technology Center than the Effort Study presented by PG&E in this GRC.

162. ORA's proposed allocation of 18% of information assets and risk management costs to construction is based on the version of the Effort Study submitted with the application, an interview with the employee who prepared the Effort Study response, and the recorded 1997 charges to construction.

163. ORA attributes 26.7% of the industrial relations department expenses to capital based on an analysis of construction related activities of PG&E's union employees and a determination that the staffing in this department could be reduced by at least 26.7% in the absence of PG&E's ongoing construction program.

164. PG&E's human resources activities would be significantly smaller in the absence of any ongoing construction activity.

165. Staffing levels in PG&E's law department would likely be reduced in the absence of an ongoing construction program.

166. The contention that third-party claims and safety engineering would not be affected by elimination of all construction activity is not realistic and is belied by PG&E's previous Effort Study.

167. The fact that PG&E cannot predict exactly when a claim will be filed, why it will be filed, or what amount it will be filed for underscores the difficulty of predicting future legal activity, and, in particular, the need to incur outside legal expenses.

168. It is reasonable to rely on the actual spending on outside legal activity in a recent year or the average recorded spending of recent years as the basis of a forecast of test-year outside legal expenses.

169. PG&E has neither demonstrated that the 1997 level of outside legal activity that ORA relies upon was unusually low, nor provided any facts and cogent analysis that demonstrate why 1999 would yield completely different circumstances requiring a dramatic increase in outside legal expenses.

170. There is little reason to assume that a department’s labor and outside services costs will be allocated to different activities in the same proportions.

171. ORA's proposed 1999-to-1996 de-escalation factor of .91498 for Account 923 is reasonable and should be adopted.

172. ORA has not shown that imputing directly assignable insurance costs associated with the Wave 1 divestiture is necessary.

173. The combination of a high deductible and a limited maximum payout limits insurer risk, and PG&E's insurers are therefore willing to cover Line 401 assets at no additional cost.

174. PG&E's latest estimate for Account 925, as set forth in the comparison exhibit, represents a reasonable and appropriate starting point for our analysis and forecast of this account.

175. Proposed adjustments to Account 925 for alleged double counting of light-duty payroll costs, an asserted difference in 1996 costs, and a constant dollar adjustment are procedurally improper.

176. Some level of expense for breach of contract suits can be expected as a reasonable, ongoing cost of doing business as a public utility.

177. A breach of contract dispute may involve competing reasonable positions of the parties to a contract dispute, and an adverse judgment does not, alone, demonstrate that PG&E acted unreasonably in the execution and administration of the disputed contract.

178. The 1994 expense of $42,656,240 for breach of contract expenses is an outlier value that should not be included in the average value used to forecast Account 925 expenses.

179. A 50% allocation to shareholders of the cost of officers' liability insurance is an appropriate reflection of the benefits received by shareholders from this insurance.

180. Tree-related claims will decline with PG&E's enhanced tree trimming efforts, and in the absence of a more rigorous quantification of the effects of the tree trimming program, TURN's proposal for a 50% reduction based on historical costs is reasonable.

181. An adjustment of $1.6 million in connection with the settlement of a 1990 lawsuit over the Campbell Complex fire, allegedly caused by a tree in close proximity to a 500 kV transmission line, is appropriate because transmission expenses fall under FERC jurisdiction

182. A $0.9 million reduction of the Account 925 estimate to reflect both the removal of damage expenses relating to the Rough and Ready fire, where PG&E was found guilty of criminal negligence, and a successful sex discrimination claim against PG&E, is reasonable and necessary.

183. ORA has not demonstrated that imputing directly assignable injuries and damages costs associated with the Wave 1 divestiture is necessary.

184. A five-year average of historical data to determine the amount of workers' compensation and medical payments allocated to construction is consistent with the forecast methodology for Account 925.

185. PG&E's forecasts for the vision plan, the dental plan, group life insurance, flexible compensation program, savings fund plan, employee relocation program, and training program have greater record support than ORA's forecasts.

186. There is no revenue requirement issue with respect to pension funding in this test year 1999 GRC.

187. In the absence of any significant demonstrated fault in PG&E's pension funding approach, or any showing that the Commission has consistently adopted ORA's approach, ORA's pension funding recommendations lack adequate support.

188. The normal cost method, limited by the maximum tax-deductible contribution under IRS regulations, is an appropriate pension funding method for PG&E to use.

189. Since the Commission has already approved amortization of the unfunded LTD transition obligation in the 1996 GRC, and the GRC decision was not challenged on the question of retroactive ratemaking, there is no question of retroactive ratemaking or inconsistency with SFAS 112 here.

190. ORA's proposed LTD adjustment of $6.8 million for 1997 medical expenses results in double counting.

191. The contention that, in some cases, PG&E and its vendors overestimated medical cost increases is not adequately supported by the evidence.

192. PG&E's estimated PBOPs medical and life insurance costs of $34.6 million and $6.7 million, respectively, were calculated by the plan’s actuary and are adequately supported by the evidence.

193. ORA's proposed one-time refund to ratepayers of $12.8 million in alleged overcollection of PBOPs costs stems from ORA's position that PG&E improperly and without authorization created regulatory assets which it assertedly added to trust contributions in 1996 and 1997.

194. PG&E claims that it is not seeking recovery of any amounts carried on its books as regulatory assets in this GRC, and ORA has not shown otherwise.

195. While PG&E's SAP-generated balances warrant scrutiny, PG&E has justified the use of SAP-related data to support PG&E's Account 926 showing.

196. There is no record evidence supporting an adjustment to Account 926 based on test-year workforce reductions by PG&E.

197. For allocating Account 926 amounts to construction, straight-time productive labor is the appropriate basis for determining pensions and benefits, and it is appropriate to use a capitalization rate that reflects this basis.

198. Adoption of an implicit estimate of employee benefits in the Diablo Canyon ratemaking proceeding does not prevent consideration of a more up-to-date determination of reasonable allocations to Diablo Canyon in this GRC.

199. PG&E's approach to Account 926 allocations to Diablo Canyon results in unreasonably low amounts.

200. ORA’s proposed allocation of pension and benefits costs to affiliates appears to be based on calculations made before PG&E reduced its forecast for pensions contributions.

201. No party contests estimating the amount of franchise fees by applying the franchise factor to the revenue requirement excluding franchise fees and uncollectibles, and adding the resulting calculation to the revenue requirement.

202. As there are no remaining issues with respect Account 928, PG&E's reduced forecast of $50,000 is reasonable.

203. Including consulting fees expended to obtain cost reductions in a GRC forecast while excluding the associated cost savings from the GRC forecast is fundamentally unfair to ratepayers, because it requires ratepayers to pay for the cost of implementing cost reductions while allocating all of the benefits of the cost reductions to shareholders.

204. The 5% markup on labor costs charged to affiliates, required by the affiliate transactions rules adopted in D.97-12-088, should be reflected in Account 930 because it is the account indicated for this purpose under the FERC USOA, and PG&E records the markup in Account 930 in its books.

205. It is inappropriate to include the cost of divestiture efforts in the 1999 GRC forecast while excluding the cost reductions resulting from the divestitures from the same forecast.

206. Consistent with our treatment of shareholder services costs, 32.5% of the costs of PG&E Corporation's annual shareholders meeting should be allocated to PG&E.

207. PG&E and ORA agree that the amount estimated for Account 931 should be zero because PG&E records A&G-related rents in Account 921.

208. There is no disagreement among the parties with respect to Account 935, which includes the costs of maintaining PG&E-owned communications equipment.

209. The record of this proceeding does not support a finding that PG&E's utility responsibilities in the area of customer account activities will diminish in any substantive way during the test period.

210. PG&E explains its requested meter reading expenses by reference to the cost shifts that resulted from its new SAP business system.

211. PG&E's request for meter reading expenses in 1999 is 15% higher than recorded spending in 1996, a year when the SAP system was in place. This amount is reasonable.

212. Standards governing meter reading have not changed since the last GRC or during the periods covered by ORA's or Enron's averaging calculations, and the continued existence of such standards does not require substantial funding increases for meter reading.

213. Data underlying the forecast of call center expenses in the 1996 GRC are less reliable than current data, and should not form the sole basis of the forecast in this GRC.

214. Due to changed circumstances resulting from the experience of the 1995 storms, some increases in call center expenses should be expected.

215. An adjustment of $2 million to PG&E's forecast of call center expenses is warranted in view of PG&E's failure to demonstrate that it fully incorporated the effect of cost saving measures that it has implemented.

216. PG&E's proposed increase in Account 903 for Account Services expenses, which is $27.3 million above the $11.7 million recorded level of spending in 1996, (which itself was the highest level of the five-year period ending with 1996) is reasonable.

217. Industrial rate schedules were complicated three years ago, and remain so now.

218. PG&E has explained how its new understanding of its role as a distribution utility justifies transferring to Account 903 expenses that were previously booked to Account 912.

219. Proving that the expense amount requested for a specific account or category of spending includes the amount necessary to perform utility services

covered by that account or category satisfies the utility's burden of proof, in the absence of countervailing credible evidence.

220. The 1996 GRC decision did not grant a blanket approval for rate recovery of all activities conducted by the Account Services Department as long as those activities are not described as Quality Contact Program activities, but rather dealt with the impermissible prospect of asking ratepayers to fund anti-competitive activities.

221. PG&E's proposal for including $7.3 million in Account Services expenses, in recognition of inefficiencies created by the elimination of DSM functions, is without merit.

222. Based on postage rate increases effective January 10, 1999, weighted postage costs in Account 903 will increase by 2.51% relative to 1997 recorded costs, resulting in an increase of $1.048 million.

223. If PG&E no longer uses an employee to staff a business office, the cost of staffing that business office is reduced.

224. The recorded uncollectible factor for 1997 reflects PG&E's credit and collections activities, and PG&E acknowledges that these activities can be sustained.

225. Ratepayer benefits in the form of CTM, early transition cost recovery, and better asset utilization are not to be foregone on the basis of speculation about competition in the long-run.

226. PG&E's proposed spending in Account 912 is supported only by a flawed CTM analysis. PG&E has failed to demonstrate clear ratepayer benefits for such expenditures, and has failed to demonstrate that its proposal does not have anti-competitive effects.

227. On a yearly average basis, PG&E's proposed net common plant additions for transportation equipment, structures, and the "Other" category for the 1997-

1999 period are more than double the 1992 through 1996 average level of net common plant additions, including CIS.

228. For purposes of estimating reasonable common plant additions, the contentions that (a) 1997 recorded spending on vehicles, not adjusted for inflation, is more reliable because it incorporates the effect of IT investments, and (b) multiple-year averaging is inappropriate because additions attributable to earthquake safety, flood disasters, and efficiency improvements are nearly complete, are unpersuasive.

229. PG&E recorded unusually large common plant retirements in 1993 and 1995, yet Enron included these extraordinary accounting entries in calculating its five-year average of common plant additions.

230. PG&E's calculation of the seven-year average of common plant net additions, which incorporates methodological corrections that PG&E believes are required if averaging is used to determine an appropriate test year plant balance, provides the most reliable basis for forecasting 1998 and 1999 common plant net additions for fleet (autos), buildings and structures, and "Other" additions.

231. There is not a persistent declining trend of M&S levels, and since M&S inventory balances are related to the planned level of construction, and capital spending has increased since the early 1990's, PG&E's proposed M&S levels for the electric and gas distribution UCCs are justified.

232. PG&E acknowledges that it has experienced a steady decline in both gas and electric customer advance balances.

233. TURN conducted a comprehensive analysis of PG&E's depreciation showing and presented its own detailed proposal for depreciation and amortization.

234. PG&E's proposed depreciation parameters, and particularly its proposed net salvage value factors, result in large revenue requirement impacts.

235. Through its proposed net salvage values factors, PG&E forecasts far higher costs than previously estimated for the removal of assets at the end of their service lives.

236. For Account 380 (gas distribution services) alone, PG&E is asking for reimbursement of $5.1 billion in depreciation expense over the life of the investment for the anticipated negative net salvage value. This amount is $3.4 billion more than the existing level, and is over and above recovery of the $1.47 billion plant balance.

237. Depreciation does not affect PG&E's ability to provide safe and reliable service, and even if the proposed or current rates of depreciation are reduced, shareholders will still recover their investments in plant over time.

238. Ultimately, the determination of depreciation parameters is a matter of subjective judgment.

239. PG&E's depreciation analysis relies on a mechanistic transformation of historical recorded accounting data into proposed depreciation parameters, and was not effectively tempered by the judgment of field personnel, engineers, and others who are in a position to make such judgments.

240. PG&E's failure to duly consider the knowledge and experience of its own personnel who are familiar with the performance of its utility assets is particularly problematic because historical accounting data alone may not disclose what is actually happening in the field, and PG&E's depreciation witness has only limited experience in energy utility operations and is not familiar with the assets in the field.

241. Geographical differences among utilities do not necessarily translate into net salvage value differences.

242. PG&E did not articulate or support a compelling rationale for determining that the cost of asset removal is much higher than it was thought to be just three years ago, even though that is what its depreciation study implies.

243. TURN has cast substantial doubt on the reliability and accuracy of PG&E's 1999 depreciation study.

244. Even though TURN's depreciation witness has extensive experience as a depreciation expert, TURN has not demonstrated that its depreciation recommendations incorporate the knowledge and experience of the PG&E personnel who are most familiar with the behavior of PG&E's utility assets.

245. PG&E's depreciation witness did not rely on the assertion that CIS plant is associated with rapidly changing technology, nor did he consult with PG&E's CIS technical evaluation team.

246. We have no basis for verifying the credibility of the assertions of the Hitachi representatives with respect to CIS service lives.

247. The Chartwell report, which is based on independent research, generally supports ORA's position on CIS plant lives, as does the in-house CIS Technical Evaluation Report prepared for CIS managers and officer sponsors in preparation for vendor selection in 1996.

248. ASLs of seven years for computer software and five years for office machines / computer equipment are unjustifiably short, but a service life of 15 years for CIS plant is reasonable.

249. Continuing the current amortization schedule in effect is consistent with our determination to continue the use of depreciation parameters adopted in the previous GRC.

250. The precepts that guided our consideration of nuclear decommissioning funding in the last GRC are appropriate and applicable in this GRC, and there is no basis for a change in our nuclear decommissioning funding policy.

251. Taking a conservative approach does not mean that every single element of the forecast of nuclear decommissioning funding needs should be slanted in favor of greater current ratepayer contributions to the decommissioning trusts; it is possible to be overly conservative in making forecasting assumptions, and to thereby create the risk of an unjustified windfall for future ratepayers at the expense of today's ratepayers.

252. Failure to recognize known, historical information about decommissioning trust fund balances has nothing to do with making conservative assumptions about the future.

253. The 50-year historic return on the Dow Jones Industrial Average of 12.5% supports the contention that continuing the assumed equity earnings of 11.0% adopted in the last GRC is a conservative approach in this GRC.

254. Using averages of ten-year rolling averages systematically gives insufficient weight to the first nine years and the last nine years of the historic period reviewed.

255. Forecasting a fixed income return of 4.89% after tax is consistent with the historic earnings rates on the fixed income portion of decommissioning funds.

256. PG&E assumption that all capital gains and interest are fully taxed each year is reasonable, since capital gains are taxed in full when the securities are sold, whenever they are sold.

257. The assumption that some equity holdings will be transferred to lower yielding bond investments as the time to perform decommissioning work approaches represents a reasonable refinement to the methodology for determining decommissioning funding needs.

258. Even though it is anticipated that funds will be expended on Diablo Canyon decommissioning beginning in 2016, most of the funds will remain in the

trusts for a number of years, and the final amounts will not be spent for an additional 20 years.

259. Assuming that all Diablo Canyon decommissioning funds will be transferred to bonds by 2015 is realistic.

260. Uncertainties in the skills, experience and professional disciplines needed for decommissioning employess, and the evolving state of the labor market for such employees makes PG&E’s forecast of labor cost escalation reasonable.

261. While higher than the respective CPI figures, ECI figures for total compensation for 2000 through 2008 are much closer to the CPI figures than the 4.7% labor escalation rate assumed by PG&E.

262. PG&E's assumption that all LLRW will be shipped to the Ward Valley site for disposal at a cost of $509 per cubic foot in 1997 dollars is reasonably conservative.

263. There is an economic incentive for PG&E and other LLRW generators to seek possible alternatives to incurring high costs for disposal at the Ward Valley site.

264. For purposes of determining the current status of, and funding needs for, the Diablo Canyon decommissioning trusts, it is reasonable to assume that PG&E may eventually have to pay $1,500 or $2,500 per cubic foot for the ultimate disposal of Diablo Canyon LLRW.

265. The developer of the Ward Valley site forecasts that LLRW disposal costs will decrease once the facility is operational, and while there may be delays before such cost decreases can be realized, the prospect of cost reductions undermines PG&E's assumption of 7.5% annual increases through 2035.

266. PG&E's proposed 7.5% LLRW disposal escalation factor reflects a contingency for the uncertainty of LLRW disposal costs.

267. PG&E's proposed 40% contingency factor for the decommissioning cost estimate does not fully accommodate uncertainties such as those associated with LLWR disposal at the Ward Valley site.

268. Since the 40% contingency factor proposed by PG&E accommodates engineering, financial, regulatory, and industry uncertainties, adding an additional contingency factor to protect against unanticipated variances in the distinct issue of LLWR disposal is justified.

269. Components of PG&E's analysis of Diablo Canyon nuclear decommissioning trust funding requirements contain calculation errors, are based on outdated information, are excessively conservative, and are methodologically flawed.

270. Applying conservative assumptions about the future, it is reasonable to conclude that the Diablo Canyon decommissioning trusts are adequately funded at this time.

271. Current ratepayers are receiving the benefit of operation and output from the Diablo Canyon nuclear powerplant; this operation and output causes continuing contamination of facilities and creation of LLRW that must be disposed of after the plant is shut down.

272. Current contributions to the decommissioning trust can be reduced from $34 million to $28 million to reflect the effect of year end 1997 trust balances without jeopardizing the financial integrity of the trust.

273. Tax benefits are created when funds from the Humboldt Unit 3 non-qualified trust are spent on decommissioning activities, but there currently is no explicit rule about how these tax benefits should be treated for ratemaking purposes.

274. PG&E does not propose additional funding for the Humboldt Unit 3 decommissioning trusts, and no other party proposed that additional funding be authorized at this time.

275. It is reasonable for PG&E to seek authorization for an on-site dry cask storage facility as a significant step towards the early decommissioning of Humboldt Bay Unit 3.

276. While the expenditure of decommissioning funds on nuclear fuel-related expenses is generally inappropriate, the circumstances at Humboldt Unit 3 justify pursuit of the on-site dry cask storage option with the expenditure of decommissioning funds. Without such an option, early decommissioning is not possible.

277. The record evidence in this GRC does not provide adequate support for the establishment of new Commission regulations governing trust fund expenditures.

278. Full-scale decommissioning of Humboldt Bay Unit 3 will not be imminent until it appears that PG&E will secure NRC authorization for its dry cask storage plan.

279. Requests that we order PG&E to actively consider and pursue alternatives to disposal of its decommissioning-generated LLRW at other facilities, and that we require PG&E, Edison, and SDG&E to file reports on the potential options for LLRW disposal, exceed the scope of this GRC.

280. PG&E has not demonstrated that additional ratepayer funds are needed to decommission its remaining fossil and geothermal facilities.

281. PG&E's proposed public purpose program funding levels are consistent with earlier determinations of the Commission.

282. ORA's and Enron's CIS witnesses are not experts in the field of large-scale CIS development and management, but they are qualified to offer credible

(opinion evidence) on the economic and regulatory matters at issue as a result of PG&E's CIS and IT proposals.

283. For purposes of determining the reasonable level of CIS capital additions that should be incorporated into revenue requirements, a utility-specific, bottom-up estimate does not constitute adequate justification for a proposal if the underlying calculation is merely an accounting exercise of collecting costs charged to the project.

284. Evaluating whether the utility-specific CIS costs are significantly different from those incurred by other utilities that have developed comparable CIS projects is a legitimate and valuable tool for determining the reasonableness of a bottom-up analysis.

285. Assumptions about inflation, amounts included in the 1993 and 1996 GRCs, incremental costs, and embedded costs affect whether PG&E's estimate of $26.6 million or Enron's estimate of $80 million in previous ratepayer funding for CIS is correct.

286. PG&E's estimate of $26.6 million in previous ratepayer funding for CIS represents only incrementally authorized funding and ignores embedded expenses associated with redirected CIS efforts.

287. PG&E has not justified its claim that more than $20 million in CIS project work could be accomplished by redirected resources at no cost.

288. The Commission clearly understood when it issued D.89-12-057 that it was approving a CIS project costing between $35 million and $53 million, and that approximately half of the project's costs would be funded with the incremental expense authorization and the other half would be accomplished through redirected staff efforts.

289. Because of the uncertainty associated with the underlying assumptions, we are not persuaded by Enron's claim and showing that ratepayers have provided as much as $80 million in CIS funding since the 1990 GRC.

290. Since approximately half of the total 1990 CIS project funding was assumed to be incremental and the other half was assumed to be non-incremental, it is reasonable to assume that ratepayers provided approximately $6.4 million per year in CIS-related funding for the period from 1990 through 1998.

291. Over the last three GRC cycles, PG&E has provided at least $55 million to $60 million in CIS capital funding. The amount of ratepayer funding is the carrying costs of that capital investment.

292. While the CIS Rewrite and nCIS projects were terminated, components were put into operation and thus became used and useful. PG&E's estimate of $36 million in ratepayer benefits from these projects is supported by the record evidence. This amount exceeds the ratepayer provided carrying cost of the capital investment, and justifies rejecting a disallowance of incurred capital investment.

293. Neither ORA's nor PG&E's comparative analyses of other utilities' CIS projects can be relied upon to make anything but broad conclusions in assessing the reasonableness of PG&E's bottom-up calculations of CIS project costs.

294. A properly conducted comparative utilities analysis would most likely yield an estimate which is no lower than ORA's estimate of $30 to $50 million for a base CIS, and which is no higher than PG&E's estimate of $88 to 144 million for a base CIS. With the removal of $62.1 million in restructuring-related CIS costs from this GRC, PG&E's remaining CIS capital additions request of $84.6 million for a base system falls within this very broad range of possible reasonableness.

295. ORA's historically-based estimate of $72 million for a CIS replacement also has several weaknesses and should be given little weight.

296. PG&E needed to accomplish significant upgrades to its base CIS, and its decision to proceed with the LCIS / Genesis approach was a reasonable response to meet the demands placed upon its system.

297. Except for the $10.8 million write-off associated with the IBM Integrity project PG&E’s requested CIS capital additions are just and reasonable.

298. The concern that PG&E will seek additional CIS funding in other proceedings is premature.

299. In deciding upon the IBM Integrity project in 1996, PG&E was aware, or should have been, that the IBM Integrity system was not sufficiently flexible to allow direct access implementation unless direct access was phased in over a period of several years.

300. Even though the Preferred Policy Decision indicated that direct access should be phased in, it allowed for the possibility of more immediate implementation of direct access, and provided adequate notice in early 1996 that different approaches to direct access implementation were possible.

301. PG&E's assumption that it could prevent immediate implementation of direct access by maintaining a dialogue with its regulators is not justified.

302. A significant portion of the IBM / Integrity effort is being incorporated into the LCIS / Genesis project, and PG&E's determination that $33.4 million associated with the IBM Integrity project is used and useful is supported by the record evidence.

303. Ratepayers should not have to pay for PG&E's assumption of the risk of deciding on the inflexible IBM Integrity approach, and PG&E's proposal to include the amount associated with the $10.8 million write-off of the project's costs is therefore not justified.

304. Funding that is designated to take care of potential problems with IBM now that the project is concluded may benefit ratepayers if PG&E is able to recover its losses, including the $3.1 million PG&E held in reserve for billing or other disputes with IBM.

305. CIS-related savings which were identified in 1995, in the San Francisco Consulting Group's business case as part of the RFP process, cannot reasonably be attributed to the LCIS / Genesis project.

306. PG&E's internal approval of the LCIS / Genesis project was not conditioned upon quantifiable, hard savings.

307. Some of the functions to which the business case attributes CIS-related savings are now found in several of the IT projects.

308. The funding for PG&E's LCIS / Genesis project authorized herein is the amount required for reasonable distribution utility needs.

309. Excessive spending authorization for certain IT projects could have the damaging effect of having ratepayers subsidize competitive efforts by PG&E.

310. PG&E's IT funding request is essentially a new phenomenon, largely involving expenditures not previously addressed in a GRC.

311. If the cost or savings estimates relied upon by PG&E's management in approving an IT project are no longer valid, the reasonableness of the project is called into question.

312. Since the spending on IT projects which PG&E seeks to incorporate in revenue requirements is essentially new, PG&E is entitled to have the reasonableness of its proposed projects reviewed on the merits.

313. PG&E's first mention of the increase to $19.4 million in its request for the OIS was in its rebuttal testimony, and PG&E has not provided an explanation of where the additional $3.2 million of booked additions can be found.

314. TURN's proposed disallowance of all OIS-related capital additions for 1997-1999 has not been justified in light of our determinations in D.99-06-080.

315. PG&E's forecasts for the JET, Call Center Enhancement, and NEBS / MLX projects are reasonable.

316. Since there is insufficient basis for finding that the FAS project is reasonable and prudent in the absence of savings that were originally projected by PG&E, it is reasonable to authorize the proposed project costs and to adopt the higher savings estimate of $13.3 million.

317. Allowing the full amount of WMS project expenses requested by PG&E would have the effect of requiring distribution customers to subsidize work performed for the benefit of others.

318. ORA has cast substantial doubt on the contention that the WMS project would be delayed by up to one year, and it would be unreasonable to deny ratepayers the benefits associated with the project for an entire GRC cycle.

319. Given new requirements for billing, including a two-page bill, and the need for efficiencies in operations, it was not unreasonable for PG&E to determine that it needed more space in the new billing center than it used in the old center.

320. The fact that PG&E's shift analysis indicated that the total costs for two-shift or three-shift operations of the billing center were about the same does not demonstrate that PG&E could have built the center with significantly less capacity than it did.

321. PG&E has provided evidence of approved job authorization for the establishment of the Test Site.

322. PG&E has not shown that the alternative projects described in the FID business case correspond to the FID project for which it seeks funding in this GRC.

323. The Middleware project had not received PG&E management authorization or undergone a detailed economic analysis.

324. In its IT Upgrades request, PG&E is essentially asking us to approve projects in concept, rather than specific, well-defined IT projects that can be considered on their merits.

325. There is no record basis for concluding that PG&E's service quality offering is likely to deteriorate if we do not adopt mandatory new standards at this time.

326. The final amount of income taxes is determined by the RO computer model run which incorporates the adopted capital and expense estimates which is described in greater detail in the May 21, 1999 Assigned Commissioner's Ruling in this proceeding.

327. Adopting a zero working cash allowance would be detrimental to ratepayers in this case and would be inconsistent with our policy of minimizing revenue requirement to the extent consistent with statutory requirements.

328. ORA's escalation figure of 3.19% for non-bargaining unit labor is based on planning information for 1997 available as of December 1996, but PG&E has determined that the actual 1997 base salary increase was 3.26% as of February 1997.

329. The inclusion of lump-sum payments accurately reflects 1997 costs for non-bargaining unit labor.

330. Because the purpose of ORA's participation in this GRC, and, therefore, the purpose of providing for the funding of ORA's consultants, is to serve the interests of ratepayers, shareholder participation in these consultant costs is not warranted under the circumstances of this proceeding.

331. PG&E's uncontested ratemaking proposal to transfer accrued costs from the consultant costs memorandum account to the respective electric and gas ratemaking balancing accounts is reasonable.

332. It is not reasonable to require a final determination of ORA consulting costs until after the issuance of a final decision on PG&E's GRC application.

333. With respect to ORA consultant costs, PG&E's legitimate concern is in obtaining reimbursement for the expenses it has incurred.

334. In the normal course of business, we expect ORA to work cooperatively with utilities, just as we expect utilities to work cooperatively with ORA.

335. The fact that PG&E experienced significant cost overruns for the SAP business / accounting system does not demonstrate that the actual cost incurred by PG&E was unreasonable.

336. When PG&E decided to go forward with the SAP system, it projected annual cost reductions of $4.0 million.

337. In light of the substantial increase in operating costs associated with the new SAP system, it is reasonable to pass on to ratepayers the originally projected cost savings of $4.0 million as a credit to A&G expense.

338. None of the expenses incurred by PG&E in the implementation of the SAP business system are included in this GRC, and passing the compensation received from SAP on to ratepayers would compensate ratepayers for expenses they did not incur.

339. Business systems replaced by SAP ran on mainframe hardware which is used for other applications, and historical data is still available through these systems for inquiries and data extracts.

340. Expanded unbundling as proposed by Enron is not necessary for purposes of setting revenue requirements in this GRC.

341. The evidence in support of PG&E's A&G Labor Two Factor Allocator outweighs the evidence in support of the four-factor method recommended by ORA, and PG&E's allocator should be used as the basis for allocations to the UCCs, except for Accounts 921, 923, and the non-labor portion of Account 922.

342. ORA's recommended Non-Labor Two Factor Allocator produces more accurate unbundling allocations for Accounts 921, 923, and the non-labor portion of Account 922.

343. While Account 930.2 contains some O&M expense, it is primarily an A&G account.

344. Because the costs of transmission-level direct connects and third-party generation ties are collected from the customers and generators who receive the benefit of the services, and are not recovered pursuant to FERC jurisdiction, PG&E's proposal for the inclusion of transmission-level direct connects and third-party generation ties in the revenue requirements set in this GRC is reasonable.

345. PG&E has not shown that it considered any opportunities to reduce residual A&G costs, even though this was clearly called for in D.97-08-056.

346. PG&E's survey of its corporate services departments basically asked managers whether divestiture would affect A&G expenditures of their respective departments, and it is neither surprising nor illuminating that managers mostly said no.

347. Authorizing reallocation of fixed A&G costs only as of the expiration date of the O&M contracts with the divested plants' buyers is directed by D.97-08-056, as confirmed in D.99-08-030.

348. Deferring the reallocation of fixed A&G costs in accordance with our previous decisions should prevent the A&G costs attributable to the PG&E employees operating the plants under the O&M contracts from being allocated to

distribution, and should result in more reliable cost savings estimates because the impact of PG&E's cost reduction plans will be more clearly understood at that time.

349. Although it was necessary for the Energy Division to use modeling experts employed by PG&E for assistance in performing the computer model runs needed to support the proposed and final decisions, we are satisfied that the procedures established in rulings of the Assigned Commissioner and ALJ provided sufficient safeguards to prevent PG&E or any other party from securing any advantage through this modeling process.

350. PG&E's proposed jurisdictional allocation methodology for retail and resale electric service has been accepted by FERC, and ORA does not object to it.

351. The record does not support a finding that the proposed attrition years 2000 and 2001 will find extraordinarily high inflation rates or unpredictable changes in financial markets.

352. PG&E has not demonstrated through clear and convincing evidence that denial of its proposed ARA mechanism would deprive it of an opportunity to earn its authorized rate of return.

353. The Northeast San Jose Transmission Relief Project is a transmission project, and the costs of this project will be recovered through FERC-approved transmission rates.

354. PG&E's July 2, 1999 motion to withdraw a portion of its revenue requirement request in this GRC that reflects restructuring-related costs is consistent with Commission directives in D.99-05-031.

355. A contingency plan for a test year 2002 GRC filing by PG&E is prudent, particularly in view of the long lead times required for processing a GRC.

356. PG&E cannot reasonably be expected to guarantee that an agricultural customer is taking service on the most cost-effective rate schedule.

357. The purpose of the agricultural rate information plan is to allow new agricultural customers to make informed decisions in choosing their agricultural rate schedules.

358. PG&E's agricultural rate information plan includes sending quarterly billing inserts to all agricultural customers, reminding them that free rate analyses are available.

359. Agricultural customers will be able to request additional follow-up analyses at any time, and those whose usage pattern for the full summer may differ significantly from any three-month summer period will have an additional opportunity to review their rate schedule selection.

360. ORA has not demonstrated that the profit center framework is necessary for determining a reasonable revenue requirement for distribution services, including potentially competitive services as defined by ORA.

361. The revenue requirements set forth in the Appendices to this decision are fair and reasonable and should be adopted.

Conclusions of Law

1. The legal obligation of the Commission in a General Rate Case is to establish just and reasonable rates to enable the utility to provide adequate service for the convenience of the public, ratepayers and employees while earning a fair return on the property it employs in providing service.

2. Allowing PG&E to collect and retain more revenue than is reasonably necessary for it to provide safe and reliable utility service, and to earn a reasonable rate of return on investments used to provide that service, would be contrary to law.

3. PG&E has the burden of proving that its current authorized revenues are unreasonable and should be adjusted.

4. PG&E may satisfy its burden of proof by showing that its proposed revenues are reasonably necessary to support a continuation of current levels of system reliability, support economic expansion in its service territory and serve existing and new customers.

5. Public Utilities Code Section 368(e) applies to PG&E and directs the filing of a 1999 test year general rate case.

6. It is PG&E's obligation generally to support its application through clear and convincing evidence.

7. In evaluating PG&E's application, we may give weight to the testimony of qualified outside experts even though such experts may not possess the same degree of personal knowledge about PG&E's facilities as PG&E's employees and consultants who testified.

8. While courts reviewing our decisions may determine whether our decisions are supported by substantial evidence in light of the whole record, this standard of appellate review does not change PG&E's obligation to sustain its burden of proof with respect to its proposals.

9. It is reasonable for PG&E to establish a nonbypassable charge for recovery of nuclear decommissioning expense.

10. PG&E's proposed electric distribution capital spending warrants careful scrutiny.

11. Consistent with our "statutory reliability" determination in D.96-09-045, our focus in this GRC is on approving revenues to support the level of investment that is required for maintenance of historical levels of reliability, responding to customer and load growth, and performing work required by others.

12. Adopting a "reliability-at-any cost" approach to analyzing electric distribution system capital spending needs, without giving any consideration at

all to the requirement for reasonable rates, would be inconsistent with our statutory duty in this GRC

13. Where the evidence is ambiguous or conflicting, presuming the value of reliability as an element of adequate service is reasonable.

14. When a party places a request before this Commission, the party has an obligation to avoid misleading the Commission in its factual presentation.

15. It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past.

16. The doctrine of estoppel does not prevent ORA from discovering new evidence or further analyzing existing evidence regarding PG&E's past maintenance practices in this GRC.

17. We should not reverse our 1992 determination that there was no reason to continue then-existing CVR reporting requirements.

18. PG&E should modify its hydroelectric and geothermal revenue requirement mechanism to replace the use of recorded capital costs with forecast costs set forth in Exhibit 28.

19. The cost of Utility Electric Generation gas meters should not be included in gas distribution rates.

20. Gas and electric supply functions cannot be assigned to a distribution UCC consistent with the Commission’s decisions on unbundling.

21. PG&E's decision to implement a new business / accounting system which involved the shifting of some costs among accounts does not prevent parties from making forecast recommendations based on long-standing and approved ratemaking techniques such as averaging.

22. A utility who uses an operational computer model as an element of its showing in a rate case must have it verified by the Commission.

23. PG&E's gas resource plan should be adopted for purposes of long run marginal cost development.

24. For ratemaking purposes, we do not allow cost recovery for more compensation than is reasonably necessary for PG&E to attract, retain, and motivate a workforce that allows it to provide adequate service.

25. While GRCs are forward looking, a utility's past maintenance practices are relevant to the analysis of a test year forecast for maintenance expense.

26. PG&E is obligated by Chapter 909, Stats. 1999 (AB 1421, Rod Wright) to provide after meter services, including carbon-monoxide testing. The approved level of CAS funding will enable PG&E to meet its statutory responsibilities.

27. Enron's request that PG&E be required to submit a compliance filing to demonstrate that PIP expenses associated with divested generation assets have been removed should be adopted.

28. Except to the extent that PG&E is able to demonstrate a clear, tangible benefit to PG&E of holding company supervision, particularly by senior officers, allocating the costs of such supervision to PG&E would be unfair to ratepayers of the distribution utility.

29. In the event of any future ratemaking proceeding in which PG&E's breach of contract expenses are at issue, PG&E should be prepared to demonstrate the reasonableness of all underlying expenses as part of its initial showing without mere reliance on the general proposition that breach of contract costs are inevitable.

30. The issue of pension funding policy is ripe for resolution, even though future ratemaking proceedings may find a need for further consideration.

31. Under certain conditions, where ratepayers clearly benefit from the activities to be funded, the Commission may approve reasonable funding for efforts to defer uneconomic distribution bypass and retain distribution customers, and allow general rate recovery of expenses associated with the administration of such rate option.

32. To carry out our policy position on revenue requirement increases, we should only make changes in authorized depreciation parameters if presented with compelling reasons for doing so.

33. If it is shown through clear and convincing evidence that failure to revise the depreciation parameters for a given account has the effect of inappropriately shifting costs to future ratepayers, we would adopt an appropriate revision in order to prevent the occurrence of that effect, and we would do the same if a current depreciation factor overcharges current ratepayers for the benefit of future ratepayers.

34. In any future rate proceeding in which PG&E places its depreciation expense at issue, PG&E will retain the burden of proof as to the reasonableness of its proposal, including any depreciation study it may present in support of its proposal.

35. PG&E's 1999 depreciation study lacks adequate substantiation, and should not be used as the basis for developing the authorized depreciation expense in this GRC.

36. Because neither PG&E's nor TURN's depreciation showing provides sufficient basis for changing depreciation parameters, and because our overarching policy position is to maintain revenue requirements consistent with provision of adequate service and a fair return on investment, ORA's secondary recommendation to continue the use of depreciation parameters adopted in the

previous GRC is necessary, appropriate, and should be adopted, with the exception of CIS-related plant.

37. PG&E's recommended approach of using the tax benefit to fund Humboldt Unit 3 decommissioning activity is reasonable and is therefore approved.

38. We affirm PG&E's request for authorization to spend up to $7 million in Humboldt Bay nuclear decommissioning trust funds for the purpose of securing the NRC licenses needed for PG&E’s proposed dry cask storage facility.

39. Nuclear decommissioning funding requires balancing three objectives: (1) assuring that the funds required for decommissioning are available at the time and in the amount required for protection of the public; (2) minimizing the cost to electric customers of an acceptable level of assurance; (3) structuring payments for decommissioning so that electric customers and investors are treated equitably over time so that customers are charged only for costs that reasonably and prudently incurred.

40. The Commission is required by Public Utilities Code Section 8325(c) to authorize collection in rates of the maximum contribution to the decommissioning trust fund deductible for tax purposes.

41. With respect to technical CIS issues where resolution of a disputed fact depends on expertise in the field of large-scale CIS development and management, the testimony of ORA's and Enron's experts should be given less weight than the testimony of PG&E's witnesses.

42. Because there is no historical basis for evaluating the reasonableness of PG&E’s Information Technology (IT) request, we require a high degree of assurance that PG&E's own management has or will have approved each proposed IT project as economically justified before we authorize ratepayers to provide funding.

43. Where there is a significant variance for any IT project's original and revised cost or savings estimates, it is incumbent upon PG&E to demonstrate that ratepayer funding of that project is just and reasonable in light of current circumstances.

44. An Attrition Rate Adjustment (ARA) is a component of the rate Case Plan that adjusts some elements of cost of service during the course of the rate case cycle for the purpose of sustaining utility earnings at an adequate level.

45. Allowance or denial of an ARA adjustment for any period is a matter within the discretion of the Commission.

46. Allowance of an ARA adjustment for 2000 is unreasonable.

47. Allowance of an ARA adjustment for 2001 is reasonable.

48. PG&E should offer ORA its full cooperation in providing ORA with the means of full and timely access to all components of the SAP system as necessary to allow ORA to complete the verification audit.

49. In order to give effect to the foregoing findings of fact and conclusions of law, the revenue requirement components and total revenue requirements set forth in the appendices will be adopted by the Commission.

50. This order should become effective on the date signed.

O R D E R

IT IS ORDERED that

1. a. Within 10 days of the effective date of this order, Pacific Gas and Electric Company (PG&E) shall file revised tariff sheets to implement the electric and gas revenue requirements set forth in Appendices B, C and D and incorporate the relevant findings and conclusions of this decision. The revised gas tariff sheets shall reflect consolidation of the gas revenue requirement change adopted herein

with the gas balancing account true-up and other relevant gas rate changes identified in Resolution G-3266. PG&E shall make one-time adjustments, with interest, to its transition revenue account, the other electric accounts, and all gas balancing accounts in which it has recorded its proposed revenue increases in this proceeding on an interim basis pursuant to Decision (D.) 98-12-078. These adjustments shall reflect the difference, including interest, between the interim electric and gas revenue requirement amounts that have been recorded between January 1, 1999 and the effective date of the revised tariff sheets, and the amounts that would have been recorded had a final decision in this proceeding been issued by December 31, 1998. The revised tariff sheets shall become effective on filing, subject to a finding of compliance by the Energy Division, and shall comply with General Order 96-A. The revised tariff sheets shall apply to service rendered on or after their effective date.

b. Within 30 days of the effective date of this order, PG&E shall file with this Commission an advice letter that includes revised versions of Appendices B, C, and D that incorporate and reflect the resolution of issues adopted in this decision based on the complete, tax version of its Results of Operations model (complete tax RO model). In accordance with the May 21, 1999 Assigned Commissioner's Ruling in this proceeding, the advice letter shall include workpapers showing the results of the analysis. PG&E shall within 10 days of filing this advice letter, and in consultation with the Energy Division, convene a technical workshop to discuss this analysis and answer parties' questions. Protests to this advice letter filing are due 20 days after the conclusion of the workshop. The advice letter shall also include all necessary revised tariff sheets to implement the revenue requirements set forth in Appendices B, C and D, as modified, which incorporate the relevant findings and conclusions of this decision. The revenue changes that PG&E files pursuant to this Ordering

Paragraph shall reflect only the difference in revenue requirements shown in Appendices B, C and D attached to this order and the revised Appendices B, C and D which PG&E files based on its complete tax RO model. These revised tariff sheets shall become effective upon approval of the advice letter by the Commission, and shall comply with General Order 96-A. The revised tariff sheets shall apply to service rendered on or after their effective date. Pursuant to D.98-12-078, the revenue requirements authorized by this decision shall take effect on January 1, 1999.

2. Within seven days of the effective date of this order, PG&E shall file with this Commission revised tariff sheets which modify the hydroelectric and geothermal generation facilities revenue requirement mechanism adopted in Ordering Paragraph 1 of Decision (D.) 97-12-096 in accordance with the relevant findings and conclusions of this decision.

3. PG&E is authorized to establish a nonbypassable charge for recovery of contributions to the nuclear decommissioning trust in the amount of $28 million annually.

4. Commission staff is directed to (a) review the request of the Office of Ratepayer Advocates (ORA) to establish a forum to consider whether Pacific Bell should be ordered to refund approximately $736,000 for structurally overloaded poles and (b) review generally the assignment of cost responsibility for repair or replacement of structurally overloaded poles in violation of our standards. The Directors of the Telecommunications, Energy, and Consumer Safety Divisions should jointly recommend any action necessary to resolve the issue of cost sharing associated with the repair and replacement of structurally overloaded poles. The review should include a determination of the extent to which actions described in D.99-06-080 (at mimeo., p. 27, *et seq.*) obviate any need for further action.

5. PG&E is authorized to expend funds for recovery of Humboldt SAFSTOR decommissioning expenses.

6. PG&E shall track the costs of the seismic design and licensing activities associated with efforts to secure authorization for on-site dry cask storage for the Humboldt Bay Unit 3 facility, and shall affirmatively raise the issue of allocating such costs to its other nuclear power plants in the first triennial nuclear decommissioning cost proceeding following the date on which it obtains any such authorization.

7. At least six months before the date that full scale decommissioning of Humboldt Bay Unit 3 begins, and no later than 30 days after any order of the Nuclear Regulatory Commission authorizing an on-site dry cask storage plan, PG&E shall file an application before this Commission to initiate consideration of the establishment of an Independent Board of Consultants to oversee the decommissioning of Humboldt Bay Unit 3. Until such time as an Independent Board of Consultants is established, PG&E shall continue outreach efforts to ensure that the Redwood Alliance and the Eureka community are kept informed about the status of the plant and decommissioning of it.

8. By June 30 of each of the years 2000 through 2004, PG&E shall submit a report on franchise fees to the Director, Energy Division and serve a copy of such report on the California City-County Streetlight Association (CAL-SLA) and any other party making a request to PG&E. Each such report shall indicate franchise fee payments made in the preceding calendar year, shall be in the format recommended by CAL-SLA in this proceeding.

9. For generation plant assets which have been divested prior to the effective date of this order, PG&E shall, no later than 30 days after the effective date of this decision, submit a report demonstrating the removal of Performance Incentive Plan costs associated with those assets from administrative and general (A&G)

costs. For other generation plant assets which are divested on or after the effective date of this order, PG&E shall submit such a report no later than 30 days after the effective date of divestiture. These reports shall be submitted to the Director of the Energy Division and served on parties to this proceeding.

10. PG&E shall establish a Quality Assurance Program (QAP) as directed in Chapter 6 of this Decision within 120 days of the effective date of this order.

11. PG&E shall establish a one way Vegetation Management Balancing Account (VMBA) to track actual vegetation management expenses in USOA 594 against the revenues authorized by this Decision.

12. The Energy Division shall conduct an audit of calendar year 1999 distribution capital pending by PG&E and report to the Commission on or before November 15, 2000. The scope of the audit will include capital projects closed to Plant in Service during calendar year 1999 and verification of amounts spent. In addition, the Energy Division shall contract with a consultant who will assess the contribution of the capital spending to system reliability, capacity and adequacy of service. PG&E shall reimburse the Commission for the cost of this contract. PG&E is authorized to record these costs in a memorandum account. PG&E shall file an advice letter implementing this memorandum account. The advice letter shall be effective on completion of review by the Energy Division for compliance with this order.

13. Upon completion of the SAP AG (SAP) business system verification audit, ORA shall file a report setting forth its findings, conclusions, substantive recommendations, and any procedural recommendations for formal Commission consideration thereof. Comments may be filed 15 days after the filing of ORA's report. The ALJ will make a determination of whether and how to proceed formally thereafter.

14. PG&E's request for authority to implement Attrition Rate Adjustments for 2000 is denied.

15. PG&E's request for authority to implement Attrition Rate Adjustments for 2001 is granted, subject to modification to take into account the results of the 1999 capital spending audit and to recognize amounts recorded in the VMBA.

16. PG&E's request for authority to implement a Major Additions Adjustment Clause for the Northeast San Jose Transmission Reinforcement Project is denied.

17. PG&E's July 2, 1999 motion to withdraw certain restructuring implementation-related revenue requirements from consideration in this proceeding is granted.

18. PG&E shall file a test year 2002 general rate case application in accordance with the Rate Case Plan.

19. No later than 60 days after the issuance of this decision, ORA shall file a final report which states, for each consultant used by ORA in connection with this GRC and for which funding is to be paid by PG&E pursuant to the January 27, 1998 Ruling of the Assigned Commissioner regarding funding of consultant services, (a) the total invoiced amount of expenses incurred in connection with this GRC proceeding, (b) the amounts which ORA determines should be allocated to PG&E's electric and gas departments, and (c) the basis for such allocations. Comments on such final report and on ORA's January 15, 1999 report on consultant costs are due 15 days after the date ORA files its final report. In the absence of comments, or upon ruling of the assigned Administrative Law Judge (ALJ), PG&E is authorized to file an advice letter pursuant to this decision for the purposes of transferring costs recorded in the consultant costs memorandum account to the respective electric and gas balancing accounts, and closing the memorandum account. In the event that comments are filed, the ALJ will make a determination of the additional procedures to be followed.

20. PG&E's proposed Agricultural Rate Information Plan is adopted to the extent provided in the foregoing discussion, findings, and conclusions, and subject to the conditions set forth therein.

21. These consolidated proceedings shall remain open pending disposition of El Dorado Project ratemaking issues, issues pertaining to the payment by PG&E of consultants hired by or on behalf of ORA, and issues pertaining to the ORA verification audit of PG&E's SAP business system.

This order is effective today.

Dated February 17, 2000, at San Francisco, California.

JOSIAH L. NEEPER
CARL W. WOOD
LORETTA M. LYNCH
Commissioners

I dissent.

/s/ RICHARD A. BILAS
Commissioner

I dissent.

/s/ HENRY M. DUQUE
Commissioner

I will file a concurrence.

/s/ JOSIAH L. NEEPER
Commissioner

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