Application	:	A.02-11-017
Exhibit Number	:	
Commissioner	:	M. R. Peevey
Admin. Law Judge	:	M. Cooke
Witnesses	:	Various

CALIFORNIA PUBLIC UTILITIES COMMISSION

ORA

Office of Ratepayer Advocates

Report on the Results of Operations For Electric and Gas Distribution For Pacific Gas and Electric Company

General Rate Case

Test Year 2003

San Francisco, California
April 11, 2003

OFFICE OF RATEPAYER ADVOCATES
REPORT ON THE RESULTS OF OPERATIONS
FOR ELECTRIC AND GAS DISTRIBUTION
FOR PACIFIC GAS AND ELECTRIC COMPANY
TEST YEAR 2003 GENERAL RATE CASE

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CHAPTER 1

EXECUTIVE SUMMARY

I. INTRODUCTION/SUMMARY

The Office of Ratepayer Advocates (ORA) issues this report in response to Pacific Gas and Electric Company's (PG&E) general rate case (GRC) Application 02-11-017, which was filed on November 8, 2002, for test year 2003. PG&E is requesting that the California Public Utilities Commission (Commission or CPUC) authorize a CPUC-jurisdictional base revenue requirement for the utility's electric and gas distribution operations of $2.716 and $1.000 billion, respectively. PG&E also seeks authorization of a revenue requirement of $1.022 billion for Utility Retained Generation (URG).

PG&E seeks an increase of $447 million for the electric department. This represents a 4.1% increase in total electric rates and a 19.7% increase in electric distribution rates. For the gas department PG&E seeks a $105 million increase. This represents a 4.5% increase in total gas rates and an 11.7% increase in gas distribution rates. PG&E also seeks a $149 million or about a 17% increase in the revenue requirement for URG operations. The increases in electric distribution and generation revenues will increase these specific components of overall bundled rates. Under current electric ratemaking, PG&E is not seeking a change in total electric rates.

Concurrent with its filing for rate relief for its test year 2003 distribution and generation operations, PG&E also filed for post test year revenue requirement increases in 2004 and 2005. PG&E is requesting increases of $64 million in 2004 and $85 million in 2005 for its electric operations. It is also requesting increases of $26 million for 2004 and $32 million for 2005 for its gas operations. For its generation operations, the utility is asking for an increase of $34 million for 2004 and a decrease of $39 million for 2005.

Following an extensive review and analysis of PG&E's filing, ORA recommends that for test year 2003 PG&E receive an increase of $170 million or 6.92% for its electric

distribution operations, an increase of $3.7 million or 0.41% for its gas distribution operations, and a decrease of $2 million or 0.23% for its URG. ORA's recommendations result in a total revenue requirement of $2,456.3 for electric operations and $900.0 for gas operations. For post-test year ratemaking, ORA developed preliminary estimated increases of $58 million for electric operations, and $23 million for gas operations in 2004. For 2005, the respective preliminary increases are $76 million for electric and $29 million for gas. The differences between ORA and PG&E's proposed revenue changes are summarized in Table 1-1.

Table 1-1

REVENUE CHANGE COMPARISON

FOR TEST AND POST TEST YEARS

(Dollars in millions)

	ORA	PG&E	PG&E>ORA
Test Year 2003			
Electric Distribution	$170	$447	$277
Gas Distribution	3.7	105	101.3
Utility Retained Gen.	(2)	149	151
Post Test Year 2004			
Electric Distribution	$58	$64	$6
Gas Distribution	23	26	3
Post Test Year 2005			
Electric Distribution	$76	$85	$9
Gas Distribution	29	32	3

ORA additionally recommends that 2006 serve as a third attrition year rather than as PG&E's next test year. The additional attrition year is justified by: (1) the need to stagger the processing of the next cycle of general rate cases for the Southern California Edison Company and PG&E and (2) the fact that a decision on test year 2003 will not be

concluded until early 2004, just six months before PG&E would normally file its Notice of Intent for a 2006 test year. ORA notes that in D.02-11-027, the most recent cost of capital proceeding, the company's rate of return was changed. ORA has included the results of that decision in its showing in this case.

II. CONSUMER ISSUES

ORA makes a number of recommendations with regard to customer service issues.

First, ORA recommends that PG&E consider addressing the needs identified in its 2001 study of its Local Office and Pay Station network such as educating customers about payment options and encouraging them to migrate from in-person payments toward lower-cost payment options, implementing unmanned, self-service payment facilities, and tracking activities other than payments at Local Offices. ORA also recommends that PG&E survey its customers on a regular basis to determine customer satisfaction and needs with respect to in-person transaction facilities. (Chapter 9-A)

Second, ORA recommends retaining PG&E's existing Quality Assurance Program of service guarantees, with the following modifications: (1) discontinue the service guarantee on response time to emergency requests, because other incentives encourage timely response and (2) add two new service guarantees, one regarding issuance of customers' first bill and another for planned outage notification. ORA also recommends that the customer credit for all guarantees under the program should be made consistent at $50 per claim. In addition, claims reporting requirements should be expanded to explain changes in the number of claims made over time or across different locations, and reports on claims activity should be submitted quarterly, rather than monthly. (Chapter 9-B)

Third, ORA recommends that PG&E explore enhancing retention efforts for customer service representatives; investigate whether to implement technology improvements and/or process changes to enhance communication between the Consumer Service Representatives (CSRs) and the field service representatives; and survey non-

English and non-Spanish speaking customers to determine whether the current AT&T translation service is responsive to their needs. (Chapter 9-C)

Fourth, ORA recommends that PG&E improve its Website functionality, especially for residential customers. PG&E should file reports with the Commission and ORA for the next three years providing updates on improvements to pge.com functionality, especially for residential customers. (Chapter 9-D)

III. ORA'S ANALYSIS

The ORA team to manage and process PG&E's 2003 GRC filing consisted of approximately 25 staff members. ORA also retained the services of Overland Consulting to assist in the analysis of PG&E's Administrative and General Expenses and taxes. Three members of the ORA's team conducted an on-site audit of PG&E's recorded Administrative and General expenses, Operations and Maintenance costs, and rate base related costs. Their report is entitled ORA's "Results of Examination Report." ORA's "Qualifications of Witnesses" provides details on ORA's multidisciplinary team with backgrounds in engineering, accounting, economics, finance, and public policy.

In the Notice of Intention (NOI) phase, which commenced on April 15, 2002, ORA identified over 400 deficiencies, which ORA asked the company to correct before accepting the company's NOI. ORA later prepared over 300 Data Requests in conjunction with the staff's review of PG&E's 14 exhibits and accompanying workpapers. In addition ORA's auditors prepared approximately 200 data requests and ORA's consultant submitted over 500 data requests to the company.

ORA visited, observed, and investigated the various operations of the company through field trips to plants, call centers, and other facilities of corporate and field activities, and met and conferred with utility witnesses and consultants on numerous occasions. Data for both 2001 and 2002 were available and utilized by the staff where appropriate to develop projections for expenses and capital expenditures. ORA's analysis and review process resulted in a number of differences with PG&E's current request for

test year 2003 and attrition years 2004 and 2005. A summary of the major differences is included in Appendix A of this chapter.

In support of its recommendation ORA submits the following six exhibits:

1. Report on the Results of Operations for Electric and Gas Distribution for Pacific Gas and Electric Company, General Rate Case, Test Year 2003 (two volumes)

2. Administrative and General Expense and Allocations Report for Pacific Gas and Electric Company, General Rate Case, Test Year 2003

3. Report on the Results of Operations for Utility Retained Generation for Pacific Gas and Electric Company, General Rate Case, Test Year 2003

4. Report on Total Factor Productivity Analysis for Pacific Gas and Electric Company, General Rate Case, Test Year 2003

5. Results of Examination Report for Pacific Gas and Electric Company, General Rate Case, Test Year 2003

6. Qualifications of Witnesses for Pacific Gas and Electric Company, General Rate Case, Test Year 2003

ORA also intends to submit additional testimony responding to the testimony filed by PG&E on March 17, 2003, and titled: "Supplemental Testimony of Pacific Gas and Electric Company on Storm Response Issues, Reliability Performance Issues, and Additional Material in the General Rate Case, Test Year 2003."

IV. ORGANIZATION OF THIS REPORT

Except for ORA's "Report on the Results of Operations of Utility Retained Generation," all of ORA's reports address both electric and gas issues. Most of the chapters in ORA's "Report on Results of Operations of Electric and Gas Distribution" provide analyses and recommendations with respect to both PG&E's electric and gas operations. These include such varied topics as Sales, Customer Accounts, A&G Expenses, Taxes, Depreciation, and Rate Base. Chapters 6, 7, 14, and 16 of that report are limited to addressing either gas or electric issues.

APPENDIX A

SUMMARY OF DIFFERENCES BETWEEN ORA AND PG&E

This appendix lists the major policy and dollar differences between ORA and PG&E with respect to the various estimates of revenues, cost allocation, operating expenses, and capital expenditures. Topics follow their listing in the Table of Contents.

1. ORA recommends increasing **Other Operating Revenues** for electric distribution by approximately $3 million and for gas distribution by $3 million. These increases in the estimated revenues are attributable to ORA's inclusion of revenue resulting from an increase in the Returned Check Fee and greater estimated income from electric and gas rental properties.

2. For **Electric Distribution Operations and Maintenance Expenses**, ORA recommends an $18 million downward adjustment to PG&E's request. This reflects adjustments to a variety of expense areas including Infrared Overhead Inspections, the Comprehensive Asset Database, Pole Restoration, Vegetation Management, and the Mapping Improvement Program.

3. ORA supports the continuation of the one-way Vegetation Management Quality Assurance Balancing Account. ORA opposes adoption of a one-way balancing account for Major Work Category EW (Request for Work at the Request of Others)

4. With respect to **Gas Distribution Operations and Maintenance Expenses**, ORA recommends a $9 million reduction in PG&E's request as the result of various adjustments associated with centralized program management and reduced overtime, lower transitioning costs, and reduced information technology and maintenance expenses.

5. ORA recommends that PG&E's requested increase for **Customer Accounts Expenses** be reduced by $6 million due to differences with respect to expenditures on customer retention activities and other services. Additional adjustments of $11

million are recommended for Accounts 902 and 903 for excessive overtime costs and differences with respect to the Customer Information System costs.

6. Regarding PG&E's proposal to increase the Insufficient Funds Fee from $6 to $10 per check, ORA recommends limiting this increase to $8 to better track inflation and mitigate the impact on low income customers.

7. The most substantial differences between ORA and PG&E are in the area of **Administrative and General Expenses**. ORA recommends that PG&E's request for Administrative and General Expenses be adjusted by approximately $235 million on a total utility basis with according adjustments to electric distribution of approximately $90 million, gas distribution of $53 million and URG of about $45 million. ORA's proposals are based on a variety of findings including: (1) PG&E's allocation of holding company costs to the utility is inconsistent with Commission policy and significantly overstates A&G expenses; (2) PG&E's allocation of A&G expenses to capital is inconsistent with Commission policy; (3) PG&E has failed to allocate all of the incremental costs associated with its bankruptcy to the below the line category; (4) the company has failed to follow Commission policy with respect to allocating a portion of the cost of the Performance Incentive Program below the line, and (5) the company's anticipated contribution to its pension fund for 2003 is not required. ORA also recommends adjustments associated with insurance refunds, third party claims, settlements, and other miscellaneous items.

8. ORA recommends a $6.4 million adjustment to PG&E's request for **Information Technology** expenses for PG&E's Consumer Information System. The adjustment is a result of normalizing these costs over a longer rate-making period.

9. With regard to PG&E's bidding process for IT projects, ORA recommends that PG&E develop and implement standards and procedures that will demonstrate that ratepayer funding for IT projects is just and reasonable.

10. ORA recommends a $9.7 million reduction in current income tax expense to correct PG&E's failure to include a deduction for capitalized A&G overheads in its forecast.

11. Regarding **Electric Distribution Plant**, ORA utilized recorded 2002 plant additions and proposes a $36 million adjustment to PG&E's proposed capital additions in 2003**.** This reflects adjustments for customer connections, under-grounding projects, pole replacement, and underground cable replacement.

12. Differences in estimates for fleet services and building and lands asset programs result in ORA's recommendation to adjust PG&E's **Common Plant** forecast by approximately $55.5 million.

13. ORA recommends adjustments to 2003 **Gas Distribution Plant** of approximately $12.7 million. This adjustment is based in part, on a different retirement forecast and an adjustment to Cost of Removal. The WAVG net additions to functional plant is also reduced by $11.7 million due to application of a different average weighting percentage.

14. Another area of significant difference is associated with depreciation expense for electric distribution. ORA recommends $103 million less electric distribution **Depreciation Expense** and $61 million less weighted average **Depreciation Reserve** as a result of: (1) ORA's access to more recent 2002 data, (2) differences in estimated capital expenditures for the test year, and (3) ORA's recommendation to maintain the existing negative net salvage values for electric distribution plant. ORA also recommends that PG&E's proposed test year gas depreciation expenses be reduced by $4 million while gas depreciation reserve be augmented by $10 million.

15. ORA proposes $108 million less in **Rate Base** due to differences in the treatment of accrued vacation and its impact on working capital.

16. There are a number of adjustments that result in the differences related to **Utility Retained Generation** operations. ORA utilized a different base for Diablo Canyon plant in developing the 2003 weighted average figure, and made

adjustments to production expenses and 2003 capital expenditures. ORA also proposes that PG&E's deferred Income Taxes be reduced by $23.4 million to reflect a 20 year rather than a three-year amortization of PG&E's fossil and hydro power plant regulatory assets. The allocation of Administrative and General expenses and updated 2003 state tax deduction also impact the URG results.

CHAPTER 2
SUMMARY OF EARNINGS

I. INTRODUCTION:

The summary of earnings tables for gas and electric distribution service are displayed in this chapter. The revenue requirements are calculated by a computer model developed by PG&E referred to as the results of operation (RO) model. The data inputs are provided by the various ORA witnesses. These inputs are then used by the RO model to calculate the results of operations.

II. SUMMARY/RECOMMENDATIONS

The results of operation for gas and electric distribution service are summarized in four tables shown at the end of this chapter. Table 2-1 contains ORA's recommended revenue requirements for gas and electric distribution service at present and proposed rates. Table 2-2 shows PG&E's requested revenue requirements for gas and electric distribution at present and proposed rates. Table 2-3 displays the comparison between ORA and PG&E revenue requirements for electric distribution at proposed rates. Table 2-4 compares ORA and PG&E's revenue requirements for gas distribution at proposed rates.

III. DISCUSSION/ANALYSIS

PG&E and its consultants developed the RO model and used it to calculate the results of operation contained in its application. ORA tested the RO model filed with the NOI and it appears to reflect the appropriate method of determining the summary of earnings.

ORA and PG&E did not include some revenues such as Other Operating Revenues in the summary of earnings tables. Whole these revenues are determined in this phase, they will be used to offset the overall revenues used in the rate design phase of this proceeding

ORA received four versions of the RO. The first was with PG&E's NOI filing, the second was with PG&E's application, the third was for the revised URG filing, and the last

version was developed pursuant to ORA request and included the recorded 2002 capital related expenditures and additions.

ORA used the latest version to calculate the results of operations depicted in this report. The various witnesses provided the input data for the RO model. Discussions and analyses of the input data are contained in various chapters of ORA's report. ORA made some minor modifications to PG&E's latest version of the RO model to accommodate some witnesses' request so that the RO could reflect their recommendations. There are some minor inconsistencies that remain between some of the witnesses' recommendations and forecast contained in the RO. ORA continues to reconcile these differences and will provide an update as soon as the work is done.

The values shown in the following tables were extracted from two RO runs. The numbers shown in the PG&E columns were extracted from the RO version that was filed with PG&E's application in November 2002. The figures displayed in the ORA columns were extracted from an ORA scenario adapted from the latest RO version provided by PG&E on March 25, 2003.

TABLE 2-1

ORA'S SUMMARY OF EARNINGS

Electric and Gas Distributions
(Thousands of Dollars)

Line No.	Description	Revenues At Present Rates		Revenues At Proposed Rates		Difference ($)		Difference (%)		Line No.
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	
1	Revenue at Effective Rates	2,279,151	902,196	2,449,151	905,914	170,000	3,718	6.94%	0.41%	1
2	Less Non-General Revenue	(7,176)	5,875	(7,176)	5,875	0	0	0.00%	0.00%	2
3	General Rate Case Revenue	2,286,327	896,321	2,456,327	900,039	170,000	3,718	6.92%	0.41%	3
4	Energy Costs	0	0	0	0	0	0	NA	NA	4
5	Other Production	14,894	0	14,894	0	0	0	0.00%	NA	5
6	Storage	0	0	0	0	0	0	NA	NA	6
7	Transmission	552	3,356	552	3,356	0	0	0.00%	0.00%	7
8	Distribution	382,747	113,863	382,747	113,863	0	0	0.00%	0.00%	8
9	Customer Accounts	195,148	151,175	195,148	151,175	0	0	0.00%	0.00%	9
10	Uncollectibles	5,707	2,240	6,132	2,250	424	9	6.92%	0.41%	10
11	Customer Services	3,266	3,225	3,266	3,225	0	0	0.00%	0.00%	11
12	Administrative and General	189,214	106,232	189,214	106,232	0	0	0.00%	0.00%	12
13	Franchise Requirements	17,171	8,646	18,448	8,682	1,277	36	6.92%	0.41%	13
14	Project Amortization	0	0	0	0	0	0	NA	NA	14
15	Wage Change Impacts	36,228	20,253	36,228	20,253	0	0	0.00%	0.00%	15
16	Other Price Change Impacts	21,149	12,333	21,149	12,333	0	0	0.00%	0.00%	16
17	Other Adjustments	0	0	0	0	0	0	NA	NA	17
18	Subtotal Expenses:	866,075	421,325	867,777	421,370	1,701	45	0.20%	0.01%	18
19	Superfund	0	0	0	0					19
20	Property	85,979	21,388	85,979	21,388	0	0	0.00%	0.00%	20
21	Payroll	29,665	16,575	29,665	16,575	0	0	0.00%	0.00%	21
22	Business	310	173	310	173	0	0	0.00%	0.00%	22
23	Other	185	103	185	103	0	0	0.00%	0.00%	23
24	State Corporation Franchise	35,138	13,757	50,015	14,081	14,878	325	29.75%	2.31%	24
25	Federal Income	190,867	59,339	249,772	60,625	58,905	1,286	23.58%	2.12%	25
26	Total Taxes	342,144	111,335	415,926	112,946	73,782	1,610	17.74%	1.43%	26
0		0	0	0	0	0	0	NA	NA	
27	Depreciation	461,728	175,288	461,728	175,288	0	0	0.00%	0.00%	27
28	Fossil Decommissioning	0	0	0	0	0	0	NA	NA	28
29	Nuclear Decommissioning	0	0	0	0	0	0	NA	NA	29
30	Total Operating Expenses	1,669,947	707,948	1,745,431	709,603	75,483	1,655	4.32%	0.23%	30
31	Net for Return	616,380	188,373	710,896	190,436	94,517	2,063	13.30%	1.08%	31
32	Rate Base	7,698,331	2,062,241	7,698,331	2,062,241	0	0	0.00%	0.00%	32
	RATE OF RETURN:									
33	On Rate Base	8.01%	9.13%	9.23%	9.23%	1.23%	0.10%	13.30%	1.08%	33
34	On Equity	8.66%	11.01%	11.22%	11.22%	2.56%	0.21%	22.80%	1.86%	34

TABLE 2-2

PG&E'S SUMMARY OF EARNINGS

Electric and Gas Distributions

(Thousand of Dollars)

Line		Revenues At Present Rates		Revenues At Proposed Rates		Difference ($)		Difference (%)		Line
No.	Description	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	No.
0	REVENUE:									
1	Revenue at Effective Rates	2,272,788	900,269	2,721,778	1,005,546	448,990	105,277	16.50%	10.47%	1
2	Less Non-General Revenue	(7,176)	5,875	(7,176)	5,875	0	0	0.00%	0.00%	2
3	General Rate Case Revenue	2,279,964	894,394	2,728,954	999,671	448,990	105,277	16.45%	10.53%	3
0										
0	OPERATING EXPENSES:									
4	Energy Costs	0	0	0	0	0	0	NA	NA	4
5	Other Production	15,443	0	15,443	0	0	0	0.00%	NA	5
6	Storage	0	0	0	0	0	0	NA	NA	6
7	Transmission	552	3,356	552	3,356	0	0	0.00%	0.00%	7
8	Distribution	401,316	122,963	401,316	122,963	0	0	0.00%	0.00%	8
9	Customer Accounts	205,747	159,266	205,747	159,266	0	0	0.00%	0.00%	9
10	Uncollectibles	5,691	2,236	6,812	2,499	1,121	263	16.45%	10.53%	10
11	Customer Services	3,682	3,623	3,682	3,623	0	0	0.00%	0.00%	11
12	Administrative and General	279,790	159,000	279,790	159,000	0	0	0.00%	0.00%	12
13	Franchise Requirements	17,124	8,628	20,496	9,643	3,372	1,016	16.45%	10.53%	13
14	Project Amortization	0	0	0	0	0	0	NA	NA	14
15	Wage Change Impacts	39,099	22,398	39,099	22,398	0	0	0.00%	0.00%	15
16	Other Price Change Impacts	24,689	14,447	24,689	14,447	0	0	0.00%	0.00%	16
17	Other Adjustments	0	0		0	0	0	NA	NA	17
18	Subtotal Expenses:	993,133	495,916	997,626	497,195	4,493	1,279	0.45%	0.26%	18
0	TAXES:									
19	Superfund	0	0							19
20	Property	86,635	21,555	86,635	21,555	0	0	0.00%	0.00%	20
21	Payroll	32,053	18,363	32,053	18,363	0	0	0.00%	0.00%	21
22	Business	312	179	312	179	0	0	0.00%	0.00%	22
23	Other	186	107	186	107	0	0	0.00%	0.00%	23
24	State Corporation Franchise	22,967	6,699	62,261	15,892	39,294	9,193	63.11%	57.85%	24
25	Federal Income	115,151	32,717	270,725	69,116	155,574	36,399	57.47%	52.66%	25
26	Total Taxes	257,303	79,618	452,171	125,211	194,868	45,593	43.10%	36.41%	26
						0	0	NA	NA	
27	Depreciation	564,702	179,391	564,702	179,391	0	0	0.00%	0.00%	27
28	Fossil Decommissioning	0	0	0	0	0	0	NA	NA	28
29	Nuclear Decommissioning	0	0	0	0	0	0	NA	NA	29
30	Total Operating Expenses	1,815,138	754,925	2,014,499	801,797	199,361	46,872	9.90%	5.85%	30
31	Net for Return	464,826	139,469	714,456	197,874	249,630	58,406	34.94%	29.52%	31
32	Rate Base	7,831,780	2,169,074	7,831,780	2,169,074	0	0	0.00%	0.00%	32
	RATE OF RETURN:									
33	On Rate Base	5.94%	6.43%	9.12%	9.12%	3.19%	2.69%	34.94%	29.52%	33
34	On Equity	4.58%	5.61%	11.22%	11.22%	6.64%	5.61%	59.18%	50.00%	34

TABLE 2-3

COMPARISON OF SUMMARY OF EARNINGS AT PROPOSED RATES

Electric Distribution

(Thousands of Dollars)

Line No.	Description	ORA	PG&E	PG&E Exceeds ORA ($)	PG&E Exceeds ORA (%)
1	Revenue at Effective Rates	2,449,151	2,721,778	272,627	11.13%
2	Less Non-General Revenue	(7,176)	(7,176)	0	0.00%
3	General Rate Case Revenue	2,456,327	2,728,954	272,627	11.10%
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	NA
5	Other Production	14,894	15,443	549	3.69%
6	Storage	0	0	0	NA
7	Transmission	552	552	0	0.00%
8	Distribution	382,747	401,316	18,569	4.85%
9	Customer Accounts	195,148	205,747	10,599	5.43%
10	Uncollectibles	6,132	6,812	681	11.10%
11	Customer Services	3,266	3,682	416	12.75%
12	Administrative and General	189,214	279,790	90,576	47.87%
13	Franchise Requirements	18,448	20,496	2,047	11.10%
14	Project Amortization	0	0	0	NA
15	Wage Change Impacts	36,228	39,099	2,871	7.93%
16	Other Price Change Impacts	21,149	24,689	3,540	16.74%
17	Other Adjustments	0	0	0	NA
18	Subtotal Expenses:	867,777	997,626	129,849	14.96%
	TAXES:				
19	Superfund	0	0	0	NA
20	Property	85,979	86,635	656	0.76%
21	Payroll	29,665	32,053	2,388	8.05%
22	Business	310	312	2	0.50%
23	Other	185	186	1	0.50%
24	State Corporation Franchise	50,015	62,261	12,245	24.48%
25	Federal Income	249,772	270,725	20,953	8.39%
26	Total Taxes				
27	Depreciation	461,728	564,702	102,974	22.30%
28	Fossil Decommissioning	0	0	0	NA
29	Nuclear Decommissioning	0	0	0	NA
30	Total Operating Expenses				
31	Net for Return	710,896	714,456	3,559	0.50%
32	Rate Base	7,698,331	7,831,780	133,448	1.73%
	RATE OF RETURN:	0.00%	0.00%	0.00%	NA
33	On Rate Base	9.23%	9.12%	(0.11%)	(1.21%)
34	On Equity	11.22%	11.22%	0.00%	0.00%

TABLE 2-4

COMPARISON OF SUMMARY OF EARNINGS AT PROPOSED RATES

Gas Distribution

(Thousands of Dollars)

Line No.	Description	ORA	PG&E	PG&E Exceeds ORA ($)	PG&E Exceeds ORA (%)
1	Revenue at Effective Rates	905,914	1,005,546	99,632	11.00%
2	Less Non-General Revenue	5,875	5,875	0	0.00%
3	General Rate Case Revenue	900,039	999,671	99,632	11.07%
4	Energy Costs	0	0	0	NA
5	Other Production	0	0	0	NA
6	Storage	0	0	0	NA
7	Transmission	3,356	3,356	0	0.00%
8	Distribution	113,863	122,963	9,101	7.99%
9	Customer Accounts	151,175	159,266	8,091	5.35%
10	Uncollectibles	2,250	2,499	249	11.07%
11	Customer Services	3,225	3,623	398	12.34%
12	Administrative and General	106,232	159,000	52,767	49.67%
13	Franchise Requirements	8,682	9,643	961	11.07%
14	Project Amortization	0	0	0	NA
15	Wage Change Impacts	20,253	22,398	2,145	10.59%
16	Other Price Change Impacts	12,333	14,447	2,113	17.13%
17	Other Adjustments	0	0	0	NA
18	Subtotal Expenses:	421,370	497,195	75,825	17.99%
19	Superfund	0	0	0	NA
20	Property	21,388	21,555	167	0.78%
21	Payroll	16,575	18,363	1,787	10.78%
22	Business	173	179	5	2.99%
23	Other	103	107	3	2.99%
24	State Corporation Franchise	14,081	15,892	1,811	12.86%
25	Federal Income	60,625	69,116	8,492	14.01%
26	Total Taxes	112,946	125,211	12,266	10.86%
27	Depreciation	175,288	179,391	4,103	2.34%
28	Fossil Decommissioning	0	0	0	NA
29	Fossil Decommissioning	0	0	0	NA
30	Total Operating Expenses	709,603	801,797	92,194	12.99%
31	Net for Return	190,436	197,874	7,438	3.91%
32	Rate Base	2,062,241	2,169,074	106,833	5.18%
	RATE OF RETURN:				
33	On Rate Base	9.23%	9.12%	(0.11%)	(1.21%)
34	On Equity	11.22%	11.22%	0.00%	0.00%

CHAPTER 3

SALES, CUSTOMERS AND PRESENT RATE REVENUES

I. INTRODUCTION

This chapter presents the Office of Ratepayer Advocates' (ORA) analysis of the Pacific Gas and Electric Company's (PG&E) forecast methodology and forecast of electric and gas customers and sales. This chapter highlights the key assumptions used in the forecast and the results of the forecasts. The sales forecast is developed to calculate revenue at present rates.

Section II presents ORA's Summary and Recommendations. Section III provides an overview of the analysis ORA conducted. Section III is divided into three sections A) Electric customers and sales forecast, B) Gas customers and sales forecast, C) Present Rate Revenues. Section IV provides concluding remarks.

II. SUMMARY/RECOMMENDATIONS

ORA analyzed PG&E's electric customer and sales forecasts and found the forecasts to be reasonable. ORA developed similar but independent econometric models to PG&E's econometric models and the results were similar with a little variation. ORA recommends the Commission adopt the following billings and sales forecast for PG&E's 2003 General Rate Case (GRC) as presented in Table 3-1 and 3-2.

Table 3-1 Electric Customers				
Customer Category	**2000**	**2001**	**2002**	**2003**
Residential	4,090,964	4,144,926	4,201,017	4,260,992
Light and Power				
Small	420,203	424,882	425,413	429,967
Medium	63,454	63,586	64,694	65,387
Large	1,311	1,317	1,304	1,317
Public Authority	34	32	30	30
Agriculture	85,041	83,501	82,673	82,151
Street Lighting	23,550	23,883	24,260	24,763
Railway	8	1	1	1
Resale	8	5	1	1

Table 3-2 Electric Sales (GWH)				
Customer Category	**2000**	**2001**	**2002**	**2003**
Residential	28,560	26,722	26,928	27,405
Light and Power				
Small	8,034	7,778	7,753	7,962
Medium	23,794	22,280	22,441	23,019
Large	16,884	15,756	15,781	15,874
Public Authority	62	122	126	126
Agriculture	3,871	3,987	3,864	3,798
Street Lighting	415	419	425	417
Railway	23	17	0	0
Resale	310	210	249	111

For the gas forecasts of customers and demand PG&E proposes to use the forecasts that were adopted in Decision 01-11-001. These forecasts were developed as a part of the 2000 Biennial Cost Allocation Proceeding (BCAP). ORA also recommends the BCAP customer and sales forecasts be adopted for PG&E's 2003 GRC. The forecasts results are presented in Table 3-3 and 3-4.

Table 3-3 Gas Customers				
Customer Category	**2000**	**2001**	**2002**	**2003**
Core				
Residential	3,648,425	3,700,264	3,672,302	3,710,741
Commercial	203,356	205,002	204,826	205,594
Natural Gas Vehicle	328	439	436	544
Wholesale	6	6	6	6
Noncore				
Industrial	1,018	902	1,106	1,124
Cogeneration	157	143	98	98
EOR	8	6	3	3
Electric Generation	17	20	16	16
Natural Gas Vehicle 4	4	4	4	5

Table 3-4 Gas Sales (MDTH)				
Customer Category	**2000**	**2001**	**2002**	**2003**
Core				
Residential	216,019	200,946	223,579	226,296
Commercial	79,920	84,032	81,804	82,283
Interdepartmental	-152	245	120	120
Natural Gas Vehicle	602	726	741	1,014
Wholesale	4,098	3,922	4,399	4,476
Noncore				
Industrial	193,117	154,761	192,006	196,978
Cogeneration	92,022	91,797	97,549	96,596
EOR	0	450	36	36
Electric Generation	261,826	313,551	177,312	175,808
Natural Gas Vehicle 4	375	373	762	1,093

ORA recommends that the Revenues at Present Rates should be updated to reflect D. 02-11-027, Cost of Capital. In Advice Letter 2421-G, 2320-E, and 2320-E-a PG&E requested $1,927,000 for gas distribution, $6,363,000 for electric distribution, and $1,564,000 for retained generation.

III. DISCUSSION/ANALYSIS

Economic Background

Economic activity within PG&E's service territory, the state of California, and the nation as a whole influence the economic and demographic drivers that are

the major inputs in the forecasting models developed for customer and sales forecasts for electricity and gas. Since economic activity affects both the electric and gas forecasts, ORA incorporates economic activity into ORA's independent analysis of PG&E's customer and sales forecasts for electricity and natural gas as well as revenues at present rates.

Although PG&E's application was filed on November 8, 2002 the economic backdrop discussed in PG&E's testimony relied upon the UCLA Anderson Forecasting Project's, "The UCLA Anderson Forecast for the Nation and California," (UCLA) June 2001 forecast and the September 2002 forecast.[1] PG&E also relied upon analysis by economy.com, the source of PG&E's economic inputs, which projected a recovery for the second half of 2002. ORA economic analysis relies upon more recent UCLA Anderson Forecasting Project, September 2002 and December 2002, as well as Global Insight's U.S. Economic Outlook, November 2002 publication.

The economic recession described by PG&E has been different than forecasters anticipated in June of 2001. It is not clear whether the U.S. economy is in a long recession, if the economy is recovering slowly, or if the economy is in a double dip recession. For example, in September of 2002 UCLA discussed the ever-changing economic forecasts for economic recovery as follows, "In December 2000, we told you there would be a short and shallow recession in 2001. In March 2001, we said we were in a recession…… even Secretary O'Neill as late as April 2002 dismissed the idea that we had a recession…."[2] Revisions by government statisticians provided data eventually supporting the assertion of three quarters of negative growth. A recession is by definition two quarters of negative growth, and UCLA contended that the economic slowdown was a recession.

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[1] PG&E Exh-7, p 4-2

[2] UCLA Anderson Forecast, Sept. 2002, page Nation-1.1

UCLA, in March 2002, described the 2001 recession as driven by reductions in business spending on equipment and software, and amplified by reductions in business inventories. While uncertainties about the future economic prospects exist, there have been sectors that faired better than other sectors. The September 2002 UCLA report describes the consumers as having "ignored the cycle completely. This is very different from the nine other recessions since WWII." Global Insight reports, "The recovery has been better than commonly perceived. Real GDP has increased 3.0% over the past year, a respectable rate by any standard." In ORA's estimation the economic downturn has been longer than previously forecasted but economic activity has been sustained by residential building activity, which has been aided by the lowest interest rates in 40 years.

A. <u>Electric Customer and Sales Forecasts</u>

ORA reviewed the econometric models PG&E applied in order to forecast electric customers and sales. The econometric models PG&E implemented are similar to models PG&E and other utilities have used in order to forecast customers and electrics sales in General Rate Cases. PG&E's econometric assumptions and model specifications are consistent with models presented in previous GRCs.

PG&E assumed that recent rate increases would continue to be in effect through 2003. PG&E also assumed that conservation programs enacted in 2001 would continue to reduce electric usage in PG&E's service territory. ORA examined the electric usage patterns and found these assumptions prudent. PG&E constructed a non-linear, double-log, econometric model in order to forecast electric customers and electric sales. An advantage of taking the log of each side of the econometric equation is that when one looks at the estimated coefficients of the sales models one can interpret the price elasticity directly from the coefficient. The elasticities were:

Residential= -.14

Commercial= -. 13

Industrial= -.06

PG&E's residential customer forecast was constructed using previous residential billings and number of households in PG&E's service territory, which were the major drivers of current residential accounts. PG&E's model specification is similar to model specifications for customer forecast in previous GRCs and also reasonable from a economic theory perspective. Measured values such as the R-squared, t-statistic, standard deviation, and Durbin-Watson statistic were in close approximation to results that should be expected from the specified residential customer forecast. The modeling techniques used for commercial and industrial customers were similar.

The electric sales forecasts were developed using variables to capture previous electric sales, seasonal effects, weather, electric rates, employment, and economic activity for each segment of the economy. The models are similar to models PG&E has previously implemented in GRCs and reasonable from an economic theory perspective. Some of the statistical measurements for the industrial model suggest incorrect model specification. ORA attempted to devise a different model in which the results were more statistically sound. ORA's modeling did not lead to any better results than the PG&E model.

B. <u>Gas Customer and Sales Forecasts</u>

ORA reviewed Decision 01-11-011 and the testimony submitted for the Biennial Cost Allocation Proceeding. The tables presented in Chapter 5, Exhibit 7, the "General Report", of PG&E's GRC are consistent with the information provided in the BCAP. ORA concurs with PG&E that these forecast should be adopted for this GRC.

C. Present Rate Revenues

ORA recommends that the Revenues at Present Rates should be updated to reflect D. 02-11-027, Cost of Capital. In Advice Letter 2421-G, 2320-E, and 2320-E-a PG&E requested $1,927,000 for gas distribution, $6,363,000 for electric distribution, and $1,564,000 for retained Generation.

II. CONCLUSIONS

The results of ORA's forecasts of customers and sales were similar to the model results of PG&E. The econometric and statistical results of the models were consistent with the results that theory predicts. The price elasticity for each model was similar to the price elasticity ORA has calculated in other GRCs.

ORA recommends the customer and sales forecasts be adopted and the resulting Revenues at Present Rates also be adopted. ORA also recommends the Revenues at Present rates be updated at the time of the comparison exhibit is filed to reflect D. 02-11-027 and PG&E's Advice Letter 2421-G and Advice Letter 2320-E-a.

CHAPTER 4

OTHER OPERATING REVENUE

I. INTRODUCTION:

This chapter presents the analysis and recommendations of ORA regarding Other Operating Revenue for electric retained generation, electric distribution, and gas distribution. Other Operating Revenues are revenues are revenues not directly derived from sale or distribution of electricity or gas. They reduce the revenues required from ratepayers. PG&E presents its Other Operating Revenue proposal in PG&E-6, Chapter 16.

II. SUMMARY/RECOMMENDATIONS

Table 4-1 compares ORA's recommended with PG&E's proposed estimates for 2003 Other Operating Revenue.

TABLE 4-1

OTHER OPERATING REVENUE

Test Year 2003

	ORA Recommended	PG&E Proposed	Difference PG&E – ORA	Percent PG&E-ORA
Retained Generation	8,159,820	8,159,820	0	0
Electric Distribution	68,878,589	65,802,663	3,075,926	4.7%
Gas Distribution	18,837,999	15,991,816	2,846,183	17.8%

III. DISCUSSION/ANALYSIS

PG&E provided recorded data for 1996 through 2001 and estimates for 2002 and 2003 for electric distribution and generation and recorded data for 1999 through 2001 and estimates for 2002 and 2003 for gas distribution. That data is presented in Table 4-1

A. Returned Check Fee

The company did not include any revenues from the proposed increase in the returned check fee in its estimates for the test year. The company estimates that its proposed increase from the current $6 to $10 per returned check would result in $466,000 in annual revenues, credited 74.4% to electric distribution and 25.6% to gas distribution. In Chapter 8 of this report ORA recommends that the fee increase be limited to $2, for a fee of $8 per check. If this recommendation is approved PG&E should realize $233,000 more in annual revenues, $173,352 in electric generation and $58,648 for gas.

B. Retained Generation

ORA accepts PG&E's estimate of $8,159,820 for retained electric generation.

C. Electric Distribution

Other Operating Revenues for electric distribution include all revenues from FERC accounts 450, Forfeited Discounts, and 451, Miscellaneous Services. The returned check fee, discussed above, is included in account 451. Also included are portions of accounts 454, Rent From Electric Property, and 456, Other Electric Revenue. ORA accepts PG&E's estimates of expected revenues from accounts 450, 456 and (other than for the returned check fee) 451. The evidence indicates, however that an upward adjustment in the revenues expected from account 454, Rents, in 2003 is reasonable.

Table 4-2 presents recorded data for 1996 through 2001 and the companies estimates for 2002 and 2003 for the account 454, Rent From Electric Property. The Table also shows year-to-year changes in revenues in dollars and percent. Note that in only one year was there a negative change, year-to-year (2000) and that for every other year the year-to-year change was a gain of at least 6.9%. The historical average, year-to-year change across the period is plus 11%.

PG&E bases its estimate for 2003 on the last recorded year, 2001, and makes no adjustment at all for 2002 or 2003. The estimate is that 2003 revenues will exactly replicate 2001 revenues. ORA does not believe the historical data support this estimate. These revenues have grown, even through a period of economic downturn, and there is no reason to expect them now to remain static. Further, in its testimony, the company indicates that it expects continued growth. At PG&E-6, 16-7 the company says that "PG&E has entered into *and plans to enter into* (emph added) agreements with telecommunications carriers to lease space…" indicating an expected future growth in rental contracts and revenues. Finally no prudent landlord would fail to adjust rents upward to account for inflation, which has been an estimated 2% per year for 2001 – 2003. Foe these reasons ORA believes revenues in this account in the test year will be higher than they were in 2001 and estimates that they will grow by the historical average of 11% per year.

If these revenues are grown at there historical rate of 11% per year, the 2003 estimate for the account 454 would increase $4,514,113, from $19,432,524 to $23,946,637. Approximately 64.3% of the account 454 revenues are allocated to Other Operating Revenue (PG&E estimates this at $12,491,818). Hence other operating revenues for electric distribution for the test year should be adjusted upward by 64.3% of the adjustment in account 454. This results in a net increase of $2,902,574.

The combination of the adjustments discussed above result in an overall upward adjustment of $3,075,926 for electric distribution.

D. Gas Distribution

Other Operating Revenues for gas distribution include all revenues from FERC accounts 487, Forfeited Discounts, 488, Miscellaneous Services, 489, Transport for Others, and portions of accounts 493, Rent from Gas Property, and 495, Other Gas Revenue. ORA's analysis of historical data indicates that upward adjustments in revenues from accounts 488, Miscellaneous Services, and 493, Rents from Gas Property, are warranted.

Table 4-3 presents PG&E's recorded data for these accounts for 1996 through 2001 and the company's estimates for 2002 and 2003. The Table also shows year-to-year change, both in net dollar and percentage. In both accounts the company based the 2003 estimate on the 2001 recorded year and proposes no changes at all in revenues from 2001 to 2003. ORA does not believe that the historical record supports these estimates.

Table 4-3 shows that recorded revenues in account 488 rose and fell erratically from 1996 through 2001. Over the entire period, however, the average year-to-year change is positive 19.1%. The volatility in this account, together with the historical positive average rate of change, both speak against the stability from 2001 to 2003 that the company projects.

ORA believes that revenues in this account will continue to grow over the long term, as the historical data suggest. However, given the volatility the data demonstrate, ORA does not suggest that the company's estimate be adjusted upward by the historical average of 19.1% per year but rather by a more modest estimated 2% yearly inflation rate over the period. This results in an upward adjustment of $4,109, from PG&E's $101,718 to $105,827.

The revenues resulting from the increased returned check fee, discussed above, are also credited to this account. This change, combined with the adjustment discussed in 13., result in a total upward adjustment in the account of $62,757, all of which is allocated to Other Operating Revenue.

Table 4-3 shows that revenues in account 493, Rent From Gas Property, fell year-to-year just once in the recorded period 1996 to 2001. Even excluding the 671% increase from 1996 to ’97 from the calculation, the average year-to-year change in this account is positive 45.7%. In light of this, the company’s estimate that there will be no change in revenues from 2001 to 2003 does not appear reasonable.

If these revenues were grown at there historical rate of 45.7% per year, the 2003 estimate for revenues from rental of gas property would increase $2,837,896, from $2,526,949 to $5,364,845. ORA does not believe a 45% growth rate is sustainable, however, and estimates instead that rents from gas property will increase by 11% per year, the growth rate determined for electric property rentals. At this rate, gas rental revenues for 2003 are estimated to be $3,113,453.

Approximately 89.4% of the revenues from account 493 are allocated to Other Operating Revenues. Hence 89.4% of the adjustment to this account should be so allocated. This amounts to an upward adjustment of $2,783,426.

The combined results of the adjustments discussed above are to increase estimated Other Operating Revenue for gas distribution by $2,599,836.

Summarizing the adjustments discussed above:

- Retained Generation

PG&E 2003 estimate: $8,159,820

ORA adjustments: none

Adjusted estimate: $8,159,820

- Electric distribution

    PG&E 2003 estimate: $65,802,663

    ORA adjustments:

        Plus $173,352 return check fee (paragraph 2)

        Plus $2,902,574 adjustment to account 454 (paragraph 8)

        Adjusted estimate: $68,878,589

- Gas distribution

    PG&E 2003 estimate: $15,991,816

    ORA adjustments:

        Plus $58,648 return check fee

        Plus $4,109 other adjustment to account 488

        Plus $2,783,426 adjustment to account 493

        Adjusted estimate: $18,837,999

IV. CONCLUSION

ORA recommends that its test year 2003 estimates for Other Operating Revenues summarized in Table 1.

CHAPTER 5

COST ESCALATION

I. INTRODUCTION

This chapter presents the Office of Ratepayer Advocates (ORA) analysis of Pacific Gas and Electric Company (PG&E) escalation for labor and non-labor expenses as well as medical expenses. In a GRC, escalation reflects the effects of inflation on the utility's expenses. Section II provides a Summary and recommendation, Section III provides a Discussion and Analysis of PG&E's request, and section IV provides concluding remarks.

II. SUMMARY/RECOMMENDATIONS

ORA reviewed the methodology PG&E devised for forecasting escalation and generally ORA agreed with the methodology.

According to the Rate Case Plan, escalation rates are to be updated on day 280[1] to reflect the most current escalation factors. ORA recommends that all escalation factors be updated on day 280. PG&E escalation factors are given in the following tables:

[1] D. 89-01-040, 30 CPUC 2d 576, 598, 604, 609. D. 93-07-030, 50 CPUC 2d 354, 359, 366.

Table 5-1 Shared Escalation Rates			
Year	Administration (%)	Labor (%)	Healthcare (%)
2000	3.83	2.96	8.15
2001	3.31	3.12	8.63
2002	2.45	3.38	10.39
2003	3.26	3.24	7.68
2004	3.53	3.37	6.18
2005	3.2	3.53	5.5

Table 5-2 Electric Escalation Rates					
Year	Nuclear Generation (%)	Hydro Generation (%)	Fossil Generation (%)	Transmission (%)	Distribution (%)
2000	3.06	2.85	2.95	2.87	2.9
2001	1.25	0.89	0.7	0.84	1.15
2002	0.06	-1.04	0.14	-0.04	-0.9
2003	2.06	1.94	2.05	1.95	1.79
2004	2.95	2.62	2.38	2.71	2.73
2005	2.24	2.06	1.81	1.92	2.16

Table 5-3 Gas Escalation Rates			
Year	Storage (%)	Transmission (%)	Distribution (%)
2000	3.73	3.59	3.29
2001	2.39	1.96	2.06
2002	0.31	-0.64	-0.19
2003	2.53	2	1.79
2004	2.93	2.8	2.69
2005	2.66	2.54	2.34

III. DISCUSSION/ANALYSIS

A. <u>Labor Escalation</u>

Global Insight's, formally DRI/WEFA, "Utility Cost Information Service" (UCIS) has been previously used by ORA as a source when forecasting escalation. Global Insight develops forecasts for Utility Cost Information Service using aggregated data for virtually all utilities in the

United States. Therefore the forecasts for escalation do not rely upon escalation for individual utilities. ORA finds the use of Global Insight to be better than PG&E's previous use of MSI, which relied solely upon detailed accounting information specific to PG&E.

The Global Insight indexes for non-labor were selected to match the business operations of PG&E: Nuclear Generation, Hydro Generation, Fossil Generation, Electric Distribution, Electric Transmission, Gas Distribution, Gas Transmission, and Gas Storage. For the administrative index a weighted average was taken between Electric A&G and Gas A&G. The labor escalation factors were developed using a weighted average. The weights were developed by analyzing the number of customers that were in the same position from the previous year.

The historical labor escalation was derived from analyzing employee salary information. PG&E divided the information into employees covered by collective bargaining agreements and those employees not covered by a collective bargaining agreement. PG&E correctly excluded those employees who had moved from one position to another position within a given year. If PG&E had failed to exclude employees that moved in position and salary, a bias would have existed in the data. PG&E used the historical information through 2002 since most salary increases occur at the beginning of the year for PG&E. This methodology results in escalation factors lower than the escalation factors reported subsequently by Global Insight.

For 2003 –2005 PG&E derived the labor escalation using DRI/WEFA, Global Insight, indices specific to the utility industry. In order to compute a single labor index for PG&E's labor escalation a weighted average was constructed. PG&E's use of the most recent historical data, 2002, in constructing the weighted average is reasonable. The Global Insight variables that were used matched closely the category of employees

escalation factor it was trying to capture. The variables Hourly Earnings Electric, Gas, and Sanitary Service Workers (AHE49NS), Managers and Administrators (ECIWSPWGRNS), and Professional and Technical Workers (ECIWSPWP&TNS) are variables ORA and the utilities have used in previous analysis.

B. Non-labor Escalation

The analysis of PG&E's non-labor escalation factors was simplified in this filing by PG&E's decision to rely upon Global Insight's "Utility Cost Information Service" rather than the labor-intensive use of Materials and Services Index that PG&E used in previous GRCs. ORA agrees with PG&E that by using Global Insight the forecasts are more objective, and that the results are more transparent. The cost escalation indices were drawn from functional categories for non-labor O&M: hydro generation, nuclear generation, fossil generation, electric transmission, electric distribution, gas storage, gas transmission, gas distribution, and administrative.

C. Healthcare Escalation

For healthcare escalation PG&E used Global Insight's Employment Cost Index, Health Insurance in order to determine the inflation for healthcare. ORA agrees with the application of this escalation factor for healthcare costs.

V. CONCLUSIONS

ORA finds PG&E's labor and non-labor escalation methodology to be reasonable for purposes of this proeceeding. ORA also recommends that the labor and non-labor escalation forecasts be updated on Day 280 as specified by the General Rate Case Plan.

CHAPTER 6

ELECTRIC DISTRIBUTION OPERATIONS AND MAINTENANCE EXPENSES

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) forecasts operations and maintenance (O&M) expenses for its electric distribution system for Test Year (TY) 2003 in exhibit PG&E-2 "Distribution Operations Costs." Certain other electric distribution system O&M expenses are found in Exhibits PG&E-3 "Customer Services Costs" and PG&E-4 "Administrative and Support Costs."[1] This chapter presents ORA's analysis of the company's proposal and presents recommendations for adjustments to forecast O&M expense levels.

Section II. of this chapter summarizes the differences between ORA's and PG&E's recommendations. Section III. presents ORA's analysis of PG&E-2 and support for ORA's forecasts and adjustments to Major Work Categories BF (Inspections and Patrols), BG (Preventive Maintenance), EW (Work Requested by Others), GA (Pole Test and Treat), HN (Vegetation Management), BA (Support), FM (Manage Information Technology), DF (Mark and Locate) and GF (Gas Mapping). Section IV. presents ORA's analysis of PG&E-3 and PG&E-4, and support for ORA's forecasts and adjustments to MWC and DD (Field Service), AB (Support), CT (Managing Electric Supply), FB (Managing Computer Systems), FR (TRBAA, QF and ID), HJ (Generation Portfolio Management Fossil), and HL

[1] In Exhibits PG&E-3 and PG&E-4 certain expenses that are traditionally considered O&M expenses are now designated as "customer service costs" and "support costs" respectively. While these expenses are ultimately recorded in FERC accounts that record the costs of the electric and gas distribution systems they are not considered part of O&M expenses as presented in exhibit PG&E-2.

(Generation Portfolio Management Hydro). Section V. provides ORA's conclusions.

II. SUMMARY AND RECOMMENDATIONS

PG&E's expense forecast for its electric distribution system for the Test Year (TY) 2003 is $443,900,000 in SAP nominal dollars.[2] The forecast expenses cover the cost of operating, maintaining, and expanding PG&E's electric distribution system to provide adequate service as defined by the Commission in PG&E's prior rate case.[3] ORA forecasts that PG&E will require $419,700,000 in expenses to support its electric distribution system. This is a recommended adjustment of $24,200,000 in nominal SAP dollars and represents a 5.5% decrease in PG&E's request.

Table 6-1

COMPARISON OF PG&E AND ORA ESTIMATES FOR TY 2003
Electric Distribution Operations Expense
(In Millions of Nominal Dollars)

	PG&E	**ORA**	**PG&E> ORA**	**% Difference**
PG&E-2 Electric Distribution O&M Expenses	$443.9	$419.7	$24.2	<5.5%>

Also included in this chapter is ORA's analysis of certain expenses that are termed electric distribution system "customer services costs" in Exhibit PG&E-3 and "support costs" in Exhibit PG&E-4. Since these expenses support the operations of the electrical distribution system they will be considered in this chapter. But, for purposes of this chapter ORA analyzes these expenses separately

[2] PG&E-2. p. 1-62. MWC expense estimates are presented in 2003 nominal SAP dollars that include adders for pensions and benefits and payroll taxes.

[3] D.00-02-046, Finding of Fact Nos. 15 and 16.

from the O&M expenses for the electrical distribution system presented in Exhibit PG&E-2 and summarized in Table 6-1 above.

In an effort to build the record in a clear and consistent manner, ORA has based its analysis on the accounting format that PG&E has chosen for its operations and application known generically as the "SAP System". ORA's proposals for adjustments are made by Major Work Category or MWC. MWC adjustments are made in nominal dollars but are ultimately translated into their component FERC Accounts in Base Year 2000 dollars so that forecasts for expenses can be input into the Results of Operations. Table 6-2 presents a summary of the differences between ORA's and PG&E's estimates by MWC, where ORA has recommended an adjustment. In this chapter, ORA discusses only those MWCs where there are recommended adjustments. The fact that ORA is not proposing specific adjustments to all of the MWCs in PG&E-2 should not be interpreted as support for PG&E's forecast for those MWCs. Rather, ORA prioritized its review of these programs by focusing on those programs that contained the most significant amount of forecast expenditures or the largest incremental increases in forecast expenses for TY 2003.

Table 6-2

SUMMARY OF ORA RECOMMENDED ADJUTSMENTS BY MWC
ESTIMATE FOR TEST YEAR 2003
Distribution O&M Expenses and Certain Support Expenses
(In Millions of Nominal Dollars)

MWC	Exhibit & Chapter	PG&E Gas or Electric Dept.	PG&E Forecast	ORA Forecast	PG&E> ORA	% Difference
BF	2/2	E	$26.1	$24.0	<$2.1>	<8.1%>
BG	2/2	E	$59.0	$55.7	<$3.3>	<5.7%>
EW	2/3	E/G	$14.4	$13.7	<$0.75>	<5.2%>
GA	2/5	E	$20.9	$18.0	<$2.9>	<14.3%>
HN	2/9	E	$132.5	$123.5	<$9.1>	<6.9%>
BA	2/11	E	$28.0	$27.2	<$0.8>	<2.7%>
FM	2/12	E/G	$13.8	$9.4	<$4.4>	<31.6%>
DF	2/13	E/G	$15.0	$14.2	<$0.78>	<5.2%>
GF	2/13	E/G	$0.45	$0.39	<$0.06>	<13.3%>
Total PG&E-2 Recommended Adjustments			**$310.2**	**$286.0**	**$24.2**	**<7.8%>**
DD	3/4	E/G	$13.7	$15.7	$2.0	15.0%
AB	4/15	E	$3.1	$2.8	<$0.2>	<7.3%>
CT	4/15	E	$4.2	$4.0	<$0.2>	<5.2%>
FB	4/15	E	$3.8	$3.6	<$0.2>	<5.8%>
FR	4/15	E	$7.2	$7.0	<$0.2>	<3.1%>
HJ	4/15	E	$1.8	$1.6	<$0.2>	<12.1%>
HL	4/15	E	$1.9	$1.7	<$0.2>	<11.7%>
Total PG&E-3and PG&E-4 Recommended Adjustments			**$35.7**	**$36.4**	**$0.8**	**2.2%**

In addition to the requested TY 2003 O&M expenses, PG&E requests balancing account treatment of expenses within two MWCs. For MWC EW, Work Requested by Others, PG&E requests that the costs incurred in performing engineering studies for customers that want to connect self-generation equipment to

PG&E's distribution system be recovered through a balancing account.[4] For MWC HN, PG&E also requests that the VMQABA or Vegetation Management Quality Assurance Balancing Account be continued in TY 2003 for the credit of underspent amounts to the ratepayers with interest.[5] ORA recommends the continuation of the one-way VMQABA and its recommended adjustments to MWC HN expenses for TY 2003. ORA does not support a balancing account for MWC EW for the recovery of the administrative and engineering costs of processing certain interconnection applications, as an appropriate amount for such costs is included in ORA's TY 2003 forecast.

III. DISCUSSION AND ANALYSIS

Electric Distribution Operations Costs, PG&E-2

PG&E's stated goal with respect to the electric distribution system is to continue to provide "adequate service" as defined by the Commission's Decision in the 1999 General Rate Case.[6] In pursuit of this goal, PG&E has centralized the management of its programs that provide for the operations, maintenance and expansion of its electric distribution system as explained in Exhibit PG&E-2, Chapter 1. ORA has endeavored to understand PG&E's centralized management and decision-making structure with respect to asset management, forecasting and unit cost for MWCs. Using MWC expense forecasts as a starting point, ORA has attempted to apply the following methods to aid in the analysis of PG&E's request, and to formulate recommendations for adjustments where appropriate:

1. Consider PG&E's Commission mandated safety and operations requirements,

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[4] PG&E-2, p. 3-13. PG&E asserts that there is no Commission sanctioned recovery mechanism that is defined with respect to PG&E's new responsibilities under ABx1-29.

[5] PG&E-2, p.9-8.

[6] PG&E-2, p.1-15, referring to D.00-02-046, Finding of Fact No. 15.

2. Perform an historical analysis of recorded expenses, units and unit costs by MWC and underlying FERC accounts,
3. Determine if any system maintenance was deferred as addressed in D.00-02-046, and
4. Determine if expenses are appropriate within parameters of the normal operating conditions of a Test Year.

The activities that drive O&M expenses for PG&E, as described in PG&E-2, are mainly categorized as non-discretionary. These are activities that are required to operate and maintain a safe electrical distribution system. These requirements are dictated by, among other requirements, the Commission's General Orders (G.O.) 95, 128 and 165. PG&E translates these requirements into methods and procedures detailed in utility operating guidelines and than associates expense levels, units to be completed and unit costs with each activity.[7]

In PG&E-2, Chapter 1, a great deal of discussion is given to the budgeting and prioritization processes for forecasting O&M expenses in TY 2003. This discussion includes the derivation and units of work and unit cost methodology to provide for the standardization and cost control of the expenses of operations, inspections and maintenance activities. Although ORA pursued an understanding of the methodology used to develop TY 2003 forecasted unit costs it never became a consistent and transparent process.[8] Consequently, duplicating PG&E's O&M expense estimates for TY 2003 on a unit cost basis has proven a difficult task for ORA. For certain of the MWCs in its electric distribution O&M expense forecast

[7] PG&E-2, Chapter 2, p.2-33. Electric Distribution Preventive Maintenance Manual, September 2000.

[8] Discovery including DR-ORA-049-001, DR-ORA-314-001 and DR-ORA-330 contain recorded units, unit costs and MWC definitions. However, ORA was not able to duplicate the derivation of unit costs forecasts for TY 2003.

ORA employs a recorded unit cost average as opposed to a forecasted unit cost utilized by PG&E.[9]

From an historical perspective, PG&E's actual expenditures since the 1999 General Rate Case in the areas of operations, inspection and maintenance continue a pattern that was identified in that General Rate Case.[10] PG&E has continued to spend less than the amount authorized by the Commission for O&M expenses. However, the gap between authorized and actual spending has narrowed between 1999 and 2002.[11]

Table 6-3

COMPARISON OF PG&E's RECORDED v. ADOPTED EXPENSES
Electric Distribution Operations
(In Millions of Base Year 2000 Dollars)

	1999	**2000**	**2001**	**2002**
Recorded Expenses	$376.8	$368.9	$354.7	$382.7
Adopted Expenses	$398.6	$387.6	$390.2	$387.4
% Difference	<5.5%>	<4.8%>	<9.1%>	<1.2%>

This quantification of historical O&M expenses raises two observations. First, although PG&E has incurred wide historical variation in the amount of O&M expenses recorded with respect to the level authorized by the Commission, the variation appears to be decreasing. Second, have the recorded spending levels for O&M been sufficient to provide for "adequate service" as asserted by PG&E? This

[9] See discussion of MWCs BF, GA and HN in Section III. of this chapter.

[10] D.00-02-046, p. 136.

[11] DR-ORA-278-001Rev2 and DR-ORA-278-002Rev2 compare adopted v. recorded O&M expense levels in Base Year 2000 dollars. With the exception of 2001 (PG&E's cash conservation efforts regarding its bankruptcy) PG&E has been spending close to authorized amounts. The gap in adopted v. recorded expense levels for 2002 displays a narrow difference of 1.2% that may be due to spending increases for the December storms. (PG&E-13, p. 3-7). Storm related issues will addressed by ORA in its report to be filed on April 28, 2003. (Assigned Commissioner's Ruling dated February 13, 2003)

issue may be addressed further in ORA's testimony to be submitted in the Reliability Performance phase of this General Rate Case.[12]

ORA is not recommending broad-brush adjustments to the operating, inspection and maintenance expense levels proposed by PG&E for TY 2003. ORA recommends adjustments to MWCs where PG&E has forecast dramatic increases in incremental spending with insufficient support and areas where PG&E is proposing additional funding for maintenance activities that were previously funded but deferred. A Test Year should reflect normal operating conditions to the extent possible. If this precept is not followed ratepayers will be forced to bear an undue burden.

At the end of each of the following analysis sections, ORA presents a table of ORA's MWC TY 2003 forecasts in underlying FERC accounts in Base Year 2000 dollars. This facilitates entry into the Results of Operations models and allows for a comparison of TY 2003 forecasts in historical FERC accounting format. ORA employed a specific methodology for translating MWC estimates into FERC accounting format for both the electric and gas distribution system O&M expenses. The essential steps are as follows:

1. ORA's MWC expense forecasts in TY 2003 nominal SAP dollars are allocated to the underlying FERC accounts for electric O&M, gas O&M, and labor-driven adders for pensions and benefits and payroll taxes.
2. Labor-driven adders for pensions and benefits and payroll taxes are removed from the forecast.
3. The remaining forecast is de-escalated into Base Year 2000 dollars for each of the FERC O&M accounts for electric and gas distribution.

It must be noted that ORA's methodology for translation of MWC expenses to FERC accounting format is performed using PG&E's own allocation estimates for

[12] A.02-11-017, Assigned Commissioner's Ruling Establishing Scope, Schedule and Procedures for Proceeding, dated February 13, 2003.

MWC and FERC accounting relationships, and PG&E's own escalation estimates for growth in O&M expenses.[13]

A. Line Patrols and Inspections – MWC BF

ORA recommends that PG&E's TY 2003 forecast expenses for MWC BF, Overhead Infrared Mainline Inspections, be adjusted to from $4,150,305 to $2,015,826 a difference of $2,134,479 or 51.4%. PG&E's forecast is based on a five-year inspection cycle for all primary mainline. ORA recommends a ten-year inspection cycle, which is consistent with recent historical patterns and practice for infrared inspections.

Table 6-4

MWC BF, Line Patrols and Inspections
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
Infrared Overhead Inspections	$4,150,305	$2,015,826	$2,134,479	<51.4%>
Total BF	$26,106,000	$23,971,817	$2,134,479	<8.2%>

PG&E conducts line patrols and inspections pursuant to the requirements of General Order (G.O.) 95. G.O. 95 does not require infrared inspections. PG&E has requested $4,150,305 for TY 2003 for overhead infrared inspections on primary distribution overhead mainline based upon infrared inspections on all primary distribution overhead mainline every five years.[14] Poles are the units of measure for MWC BF. For TY 2003 PG&E has forecasted 959,917 units to be inspected. This is approximately three times the number of units completed for the year 2001. According to PG&E

[13] PG&E-2 includes MWC to FERC allocations at the end of each chapter and includes escalation factors in the accompanying workpapers associated with each chapter.

[14] PG&E-2, p. 2-24.

infrared inspections are a cost effective method of inspecting overhead lines for temperature differentials that are predictive of potential failure.[15]

ORA does not dispute the efficacy or the need for the program but does question whether the estimated number of inspections can be completed. The recorded number of units completed for 2002 was 251,689, while the estimate for both 2002 and 2003 is 959,917 units completed.[16] At the forecast rate, over a five-year cycle 4,799,585 infrared inspections would need to be completed. It is unclear how the requested inspections would be completed given that only 251,689 inspections were completed in 2002.

PG&E asserts without support that the program would produce cost savings: "[t]his is a cost effective means of preventing future equipment failures that would require expensive corrective repairs."[17] If costs savings were realized, ORA would expect that PG&E would forecast such savings in expenses related to MWC BH (Corrective Maintenance), or in future capital expenditures for MWC 17 and 57 (Emergency Response and Maintenance, respectively). However, no such savings have been incorporated into the forecasts. Increasing expenses on the basis of future savings without also incorporating the savings into the forecast is inconsistent with PG&E's own assertions and is unfair to ratepayers.

ORA recommends adjusting the forecast units downward based upon a ten-year program aimed at inspecting 479,958 units at an historically derived unit cost of $4.20. This produces an adjustment expense total for TY 2003 of $2,015,826. The ORA forecast of 479,958 units, under a ten-year cycle, is almost double the actual units completed for 2002. As previously noted, PG&E conducts required line patrols and inspections

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[15] PG&E-2, Chapter 2 Workpapers p.2-157, Utility Operations Guideline S20007.
[16] DR-ORA-049-001 and DR-ORA-314-001.
[17] PG&E-2, p.2-27, footnote (b).

under the rules of General Order 165. Infrared overhead mainline inspections are in addition to overhead line inspections and patrols that are requirements of G.O. 165. The TY should reflect normal operating conditions not an accelerated schedule with corresponding expenses for an inspection process that is not currently required. Completing one-fifth of the entire system, starting in TY 2003 is overly ambitious, so ORA proposes a ten-year cycle that is consistent with historic practice. Therefore, ORA recommends an adjustment of $2,134,479.

B. <u>Preventive Maintenance – MWC BG</u>

ORA recommends that PG&E's TY 2003 forecast expenses for MWC BG or the comprehensive asset database be adjusted from $8,335,402 to $5,001,241 a difference of $3,334,161 or 40.0%. PG&E's forecast is based on a six-year schedule to input each and every electric device that carries an inspection requirement. ORA recommends using a ten-year schedule to forecast the expenses associated with field staff labor needed to input asset information and for database administration.

Table 6-5
MWC BG, Preventive Maintenance
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
Comprehensive Asset Database	$8,335,402	$5,001,241	$3,334,161	<40.0%>
Total BG	$59,025,000	$55,690,839	$3,334,161	<5.7%>

PG&E bases its request of $8,335,402 in expenses for TY 2003 upon a reduced future administrative burden, more effective response to system problems and better tracking of assets.[18] While ORA agrees that future efficiencies can be realized through centralizing information on all assets in

the electric distribution system, the plans for how the identification would be integrated into a GPS system or even into the Work Management System (WMS) or Field Automation System (FAS) for assigning fieldwork are not supported.

The input function of the comprehensive asset database does not have a unit or unit cost associated with the forecast for expenses, but rather relies on a completion of inputs for one-sixth of the system per year starting in TY 2003.[19] ORA recommends that inputs to the database be completed over a ten-year timeframe so that expenses are not loaded into TY 2003. This undertaking is massive and includes all electric devices that have an inspection requirement.

Since field staff are inputting information during inspections and patrols, ORA also recommends that PG&E update the Electric Distribution Preventive Maintenance Manual to include the input function as part of the regular inspection processes. This comprehensive database should be fully integrated with all of PG&E's information management systems for operations, maintenance and emergency response. ORA further recommends that the information gathered in the asset database be summarized for the Commission on an ongoing basis when PG&E submits its annual G.O. 165 Compliance Plans.[20]

In summary, ORA recommends that the comprehensive asset database project be initiated in TY 2003. However, the timeframe for the project should be increased to ten years because the benefits of a six-year

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[18] PG&E-2, p.2-40.

[19] PG&E-2, Chapter 2 Workpapers, p. 2-16.

[20] D.97-03-070 requires that PG&E submit an annual compliance plan and report under G.O. 165 beginning in 1997.

program have not been demonstrated.[21] ORA recommends that the forecast expenses for MWC BG should be decreased by $3,334,161 for TY 2003.

C. Work at the Request of Others – MWC EW

ORA recommends that PG&E's TY 2003 forecast expenses for MWC EW or Work at the Request of Others be adjusted from the forecast amount of $14,415,000 to $13,663,227 a difference of $751,774 or 5.5%. PG&E's request is based on expenses associated with processing applications for customers that wish to connect self-generation equipment to PG&E' electric distribution system. PG&E's forecast is based on limited actual experience because both the legislative and regulatory incentive programs for promoting renewable self-generation resources and net energy metering have been initiated recently.[22] ORA recommends that the TY 2003 forecast reflect the actual number of applications processed in 2002.[23]

Table 6-6
MWC EW, Work at the Request of Others
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
Processing Interconnection Applications	$3,911,330	$3,159,557	$751,774	<19.2%>
Total EW	$14,415,000	$13,663,227	$751,774	<5.2%>

PG&E has estimated that there will be an increasing number of applications by customers requesting to interconnect their self-generating electric equipment to the PG&E distribution system in 2002. This allows customer-generators to net their electricity usage drawn from the utility grid

[21] DR-ORA-337-002.

[22] ABx1-29 and D.02-03-057 expand the incentives for self-generators to request interconnection with PG&E's electric distribution system.

[23] R.99-10-025, Order Instituting Rulemaking into Distributed Generation, PG&E Company's Report in Compliance with Ordering Paragraph 5 of D.02-03-057, Exhibit A –

against their own electricity generation and receive credits on their bills. The three types of interconnection applications for self-generation are: Standard E-NET or net-metering for self-generation projects of less than 10 kW, Expanded E-NET or net-metering for self-generation projects greater then 10 kW but less than 1 MW, and Rule 21 or non-net-metering self-generation projects of less than 1 MW. PG&E quantifies the in-depth engineering studies and complex administrative processing required for interconnection applications but fails to justify the number of applications to be processed in TY 2003.[24]

ORA's forecast for TY 2003 is based on annualizing recorded 2002 data for interconnection applications processed and reported to the Commission.[25] Using PG&E's assertion that the forecast number of electric interconnection applications will not increase from 2002 to 2003, ORA has set its forecast for TY 2003 equivalent to its annualized 2002 estimate.[26]

Table 6-7

MWC EW, Forecast Interconnection Applications Processed TY 2003

	PG&E	ORA	PG&E>ORA
Standard ENET Applications	2,000	1,391	<609>
Expanded ENET Applications	120	81	<39>
Rule 21 Applications	50	78	28

Distributed Generation Cost matrix. ORA has annualized the number and cost of interconnection applications for 2002.

[24] PG&E-2, Chapter 3 Workpapers p. 3-100.

[25] R.99-10-025, Order Instituting Rulemaking into Distributed Generation, PG&E Company's Report in Compliance with Ordering Paragraph 5 of D.02-03-057, Exhibit A – Distributed Generation Cost matrix. ORA annualized the number and cost of interconnection applications for 2002.

[26] PG&E-2, Chapter 3 Workpapers, p. 3-99. Electric interconnections are forecasted to be flat from 2002.

ORA recommends that the costs associated with processing interconnection applications should be monitored and reported to the Commission through continuation of required compliance reports and memoranda accounts.[27] It is imperative that ratepayers, generally, are not saddled with any extra costs associated with processing interconnection applications that are not balanced against the benefits derived from net energy metering.

ORA also recommends that PG&E's requested balancing account treatment for "study costs" associated with processing of E-NET applications be denied.[28] PG&E is requesting recovery in rates for the TY 2003 expenses associated with processing interconnection applications and should have any existing balancing accounts discontinued with the implementation of the rates from the instant application.

D. <u>Pole Test and Treat – MWC GA</u>

ORA recommends that PG&E's TY 2003 forecast expenses for MWC GA, Pole Test and Treat, be adjusted to from $6,480,000 to $3,856,875 a difference of $2,983,125 or 43.6%. PG&E's forecast is based on restoring or "stubbing" 12,000 wooden poles in TY 2003. This total includes 4,500 poles that were not completed as scheduled in 2001. It is inappropriate to include in rates and recover from ratepayers the deferred maintenance expenses associated with stubbing for these 4,500 poles. The costs associated with stubbing these poles have already been funded by ratepayers . They should not be required to pay a second time.

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[27] D.02-03-057, Ordering Paragraph Nos. 3 and 5. See, also, PG&E Cal. P.U.C. Sheet No. 18831-E, Net Energy Metering Memorandum Account, June 3, 2002.

[28] PG&E-2, p. 3-13.

Table 6-8

MWC GA, Pole Test and Treat

(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
Pole Restoration	$6,840,000	$3,856,875	$2,983,125	<43.6%>
Total GA	$20,903,000	$17,919,875	$2,983,125	<14.3%>

As part of the MWC GA program PG&E restores, as opposed to replaces, deteriorated wooden poles using techniques such as steel truss "stubbing", pole extensions, splints or fiber wraps.[29] PG&E claims that this restoration work should be treated as an expense under FERC accounting rules.[30] ORA agrees with that interpretation but does not agree with PG&E's estimate of the number of units that should be used to develop the TY 2003 forecast.

The poles that were not restored with stubbing in 2001 should not be the responsibility of ratepayers in 2003. PG&E states that "[i]n 2000 and 2001, the number of poles stubbed was significantly reduced from historic levels dues to…and 2000/2001 cash conservation efforts." PG&E also asserts that the entire backlog of poles (22,500 poles) that require stubbing should be completed in the next five years starting in TY 2003.[31] This clearly amounts to a request for recovery for deferred maintenance.

PG&E had sufficient funding in 2000 through 2002 to complete the scheduled work. However, PG&E unilaterally elected to defer the work until later years. As previously discussed and shown in Table 6B-3, PG&E

[29] PG&E-2, p.5-14.

[30] Ibid., footnote [7].

[31] PG&E-2, p. 5-16. PG&E asserts that 22,500 poles require stubbing. If these poles were completed in the requested five-year time frame, PG&E would have to complete an additional 4,500 poles per year beginning in TY 2003 and continuing through at least the attrition period.

has underspent the level of O&M expenses authorized by the Commission. PG&E should not be permitted to recover costs in TY 2003 for system maintenance that was deferred from prior years. This recommendation is consistent with past Commission precedent regarding deferred maintenance.[32]

In required filings with the Commission, on the affects of it cash conservation measures in 2001, PG&E has stated that no maintenance was being deferred with the exception of certain pole replacement programs.[33] As noted above, the costs associated with MWC GA or pole stubbing (which technically is not pole replacement) were also being deferred from prior years and should not be included in TY 2003 forecast.

In summary, ORA's recommended adjustment is based on a historical unit cost for stubbing of $514.25 per pole. ORA applies this unit cost to 7,500 poles (12,000 requested minus 4,500 deferred poles) to produce an estimate for expenses for TY 2003 of $3,856,875 which is an adjustment of $2,983,125 below PG&E's request.

E. <u>Vegetation Management – MWC HN</u>

ORA recommends that the TY 2003 forecast expenses for MWC HN or Vegetation Management be adjusted to from $132,500,000 to $123, 525,928 a difference of $9,126,217 or 7.4%. PG&E's forecast is based on routine trimming and removal of trees, vegetation clearing and continuation of the extraordinary tree removal program that was instituted under the Settlement Agreement approved by

[32] 10 CPUC2d 155, 345.

[33] DR-CIW-075-003. "Response of PG&E Company to the ACR seeking additional information regarding the impact of proposed layoffs." A.00-11-038. January 25, 2001.

D.99-07-029, which expired in 2003.[34] ORA recommends adjusting the TY 2003 forecast for routine trims and removals and their corresponding unit costs to reflect average historical levels. ORA recommends that PG&E's request to continue the extraordinary tree removal program, instituted under the Settlement, be allowed but only if average historical unit costs are utilized for the forecast. ORA also recommends that PG&E's request to continue its Quality Assurance Program (QAP), instituted under the Settlement, be continued. However, only 50% of the program should be funded by ratepayers – this translates to an adjustment of $364,000 from PG&E's QAP request of $728,000 for TY 2003.[35]

Table 6-9

MWC HN, Vegetation Management
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
Tree Trim & Removal	$120,699,259	$111,929,204	$8,762,217	<7.3%>
Continuation of QAP	$728,000	$364,000	$364,000	<50.0%>
TOTAL HN	$132,500,000	$123,525,928	$9,126,217	<6.9%>

PG&E forecasts $120,699,259 for MWC HN based upon a composite unit cost of $57.25 and a composite of 2,108,824 units which include routine trim and removal units (routine units) for TY 2003. This composite unit forecast includes 80,000 units of removal and replacement (removal units) that is requested as a continuation of the Settlement Agreement's tree

[34] D.99-07-029, Investigation on the Commission's Own Motion into the Operations and Practices of The Pacific Gas and Electric Company in Connection with Public Utilities Code Section 451, General Order 95, and Other Applicable Standards Governing Tree-Line Clearances, Appendix A " Settlement Agreement", July 20, 1999.

[35] PG&E-2, p. 9-17 and 9-19.

removal program at the same forecasted composite unit cost as routine units.[36]

ORA takes issue with both the total number of units proposed by PG&E and the use of a composite unit cost for forecasting TY 2003 expenses. Given the annual variability in this function, actual experience should be utilized in forecasting both the number of units of work and the unit cost of that work in TY 2003.[37] ORA forecasts that PG&E can complete 1,894,159 routine units and 80,000 removal units based on historical averages for the years 1999 to 2002. This produces a total of 1,974,159 units. Each of these discreet activities should have discreet unit cost based on PG&E's actual experience in implementing the programs approved by the Commission as part of the Settlement Agreement.[38]

Table 6-10

MWC HN, Units and Unit Costs for Tree Trim and Removal
(In Nominal Dollars)[39]

	1999	2000	2001	2002	Average
Routine Units	1,980,337	1,784,300	1,940,686	1,871,312	1,894,159
Unit Cost	$56.11	$54.74	$57.66	$60.89	$57.35
Removal Units	N/A	107,159	154,900	93,467	118,509
Unit Cost	N/A	$36.42	$47.77	$39.53	$41.24

The Settlement Agreement removals and replacements should be tracked separately and reported to the Commission by both unit cost and units completed. If this portion of the program is effective then tree units and unit costs for routine trimming and removal should decrease over time and be captured in the Vegetation Management Quality Assurance Balancing

[36] PG&E-2, p. 9-22.
[37] Ibid.
[38] PG&E-2, Chapter 9 Workpapers p. 9-16, DR-ORA-049-001 and DR-ORA-314-001.
[39] Ibid.

Account (VMQABA). This is a one-way balancing account that returns unexpended funds to ratepayers.

ORA agrees that the Settlement Agreement requirement regarding the establishment of a Quality Assurance Program (QAP) be continued.[40] But, ORA recommends that QAP expenses not be fully apportioned to ratepayers as requested by PG&E. A shared responsibility between ratepayers and shareholders provides an appropriate incentive for managing the vegetation program with this centralized oversight function of identifying and correcting root causes of system problems. If PG&E's vegetation management program is managed and targeted efficiently, both the ratepayers and shareholders will benefit. Any cost savings generated as a result of the QAP will be passed to ratepayers through the VMQABA. Any decreased liability for tree-related damages will accrue to the shareholders.

The past findings of the Commission support partial shareholder responsibility for the continuation of the QAP. The Commission has found that expenses incurred as a result of negligence, as in the case of the Rough and Ready fire, should not be borne by the ratepayers.[41] PG&E's efforts, including full annual patrols of all primary distribution circuits and the QAP's added oversight activities for identifying areas of higher potential risk, should reduce tree-related incidents and accidents.[42] If tree-related incidents are reduced the chances of incurring expenses due to any negligence associated with vegetation management should be reduced. Shareholders are the beneficiaries of this reduced liability. Although this reduced liability is not quantifiable, ORA recommends that shareholders should be responsible for 50% of the expenses associated with QAP.

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[40] PG&E-2, p.9-17.
[41] D.00-02-046, Findings of Fact 180 and 182.
[42] PG&E-2, pp. 9-6 and 6-22.

In summary, ORA supports PG&E's request for continuation of the VMQABA whereby underspent amounts are credited to ratepayers.[43] ORA further recommends that PG&E's forecasted amount for MWC HN be adjusted by $8,103,917.

F. Electric Distribution Operations – MWC BA

ORA recommends that the TY 2003 forecast expenses for MWC BA, Operate the Distribution System, be adjusted to from $28,010,000 to $27,242,000 a difference of $768,000 or 2.8%. PG&E's forecast is based, in part, on twelve California ISO Stage 3 related emergencies (four full events including rotating outages and eight staging events in anticipation of rotating outages) occurring in TY 2003.[44] ORA does not believe that these Stage 3 events will take place in TY 2003 and that the associated expenses should not be included in rates.

Table 6-11
MWC BA, Electric Distribution Operations
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
CAISO Stage 3 Events	$768,000	$0	$768,000	<100.0%>
TOTAL BA	$28,010,000	$27,242,000	$768,000	<2.7%>

PG&E has forecasted 12 CAISO ordered Stage events in TY 2003 and supported the forecast with various publications by industry experts and various agencies of the State of California.[45] ORA does not discount the expertise presented but must balance forecasts against the reality that there were not any Stage 3 ordered emergency events in 2002. ORA maintains that circumstances have changed considerably in the last year. Among other

[43] DR-ORA-336-002.
[44] PG&E-2, p. 11-11.
[45] DR-ORA-134-002 and DR-ORA-162-001.

things, California investor owned utilities have become responsible for procuring electricity for their customers, and the market has stabilized. Recent experience and changed circumstances indicate that Stage 3 events are unlikely. Therefore, ORA recommends that the expenses forecast for TY 2003 Stage 3 events be adjusted to zero.

G. Manage Information Technology – MWC FM

ORA recommends that the TY 2003 forecast expenses for MWC FM, Manage Information Technology, be adjusted to from $13,776,000 to $7,251,000 a difference of $4,350,000 or a 60.0% decrease. ORA's recommended adjustment is based on allowing PG&E to recover the costs associated with its Mapping Improvement Program (MIP Phase II – for mechanizing system maps) over a longer time frame than requested.[46]

Table 6-12

MWC FM, Manage Information Technology
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
MIP Phase II	$10,875,000	$6,525,000	$4,350,000	<40.0%>
TOTAL FM	$13,776,000	$9,426,000	$4,350,000	<31.6%>

ORA agrees with the concept of digitizing and mechanizing all of the electric distribution system maps that are relied upon for operations, maintenance and emergency response. However, ORA questions the asserted goal of converting all maps to a common electronic platform in the three-year time frame requested. ORA suggests that PG&E's approach to prioritize all maps slated for digital conversion should allow for a longer time frame for actual conversion. Maps that are in less demand and that

[46] PG&E-2, p.12-15.

require the least changes could be reserved for the later years of the conversion program.

ORA recommends that the MIP Phase II program be carried out over a five-year time frame as opposed to a three-year program. Normalizing this expense over a longer time period should allow PG&E to complete the program with less contract labor then contemplated and would spread these expenses over a longer time period.[47] ORA also recommends that PG&E report to the Commission on the progress of MIP Phase II because, like the comprehensive asset database addressed in Section III.B. above, it will benefit the Commission in its safety oversight function to have access to both a comprehensive listing of assets and fully digitized maps for inspections and investigations.

ORA has allocated the recommend reduction to both the electric and gas distribution systems based on PG&E's allocation of the TY 2003 estimate for MWC FM into component FERC accounts 587 and 880.[48]

H. <u>Mark and Locate – MWC DF</u>

ORA recommends that the TY 2003 forecast expenses for MWC DF, Mark and Locate, be adjusted from $15,026,000 to $14,250,000 a difference of $776,000 or a 5.2% decrease. ORA's recommended adjustment is based on apportioning the expenses for MWC DF to both the Electric and Gas Distribution systems.[49]

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[47] DR-ORA-162-002.

[48] PG&E-2, p. 12-21.

[49] PG&E-2, p. 13-79, Table 13-27. Proportions of expenses allocated to FERC Accounts 584 and 874 for electric and gas O&M expenses provided the ratio for ORA's adjustments to MWC DF.

Table 6-13

MWC DF, Mark and Locate
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
DF - Electric Distribution System	$12,616,000	$11,902,000	$714,000	<5.7%>

The basic activity of MWC DF is to notify builders, contractors, and others planning to excavate with information about the location of PG&E's underground facilities through the Underground Service Alert (USA) system.[50] ORA's recommended adjustment is based on an historic average of USA tags or units processed. ORA's full analysis of MWC DF forecasts for TY 2003 are contained in the Gas Distribution O&M Expenses section in Chapter 7 of this report.

I. <u>Gas Mapping– MWC GF</u>

ORA recommends that the TY 2003 forecast expenses for MWC GF, Gas Mapping, be adjusted from $450,000 to $390,000 a difference of $60,000 or a 15.4% decrease. ORA's recommended adjustment is based on apportioning the expenses for MWC GF to both the Electric and Gas Distribution systems.[51]

Table 6-14

MWC GF, Gas Mapping
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
GF – Electric Distribution System	$450,000	$390,000	$60,000	<13.3%>

[50] PG&E-2, p. 13-17.

[51] PG&E-2, p. 13-83. Proportions of expenses allocated to FERC Accounts 588 and 880 for electric and gas O&M expenses provided the ratio for ORA's adjustments to MWC GF.

MWC GF tracks expenses associated with PG&E's permanent gas facility records. These records detail the size, material type, location, configuration, and other essential information needed to identify the thousands of miles of underground distribution main and millions of services. Specific activities include posting information for construction orders that have been closed in the accounting system, making map and data corrections, and providing information to avoid conflicts with government agency-proposed utility and infrastructure projects.[52] ORA's full analysis of MWC GF forecasts for TY 2003 are contained in the Gas Distribution O&M Expenses section in Chapter 7 of this report.

J. Summary of ORA Adjustments

ORA proposes the following adjustments for the MWCs presented by PG&E for operations of the electric distribution system (Exhibit PG&E-2). As discussed in Chapter 6-A of this report, ORA has developed a specific methodology for translating MWC expense forecasts into FERC accounting format. Table 6-15 summarizes both MWC and FERC forecasts for TY 2003 and then states ORA's recommended adjustment in FERC account format adjusted into Base Year 2000 dollars. This last step allows for ORA's forecast to be input into the Results of Operation Model and allows for comparisons in the traditional general rate case methodology.

[52] PG&E-2, p. 13-72.

Table 6-15

Summary of ORA's MWC Adjustments by FERC Account, PG&E-2
(In Base Year 2000 Dollars)

	PG&E's TY 2003 Forecast	ORA's TY 2003 Forecast	PG&E>ORA
MWC-BF			
583	$13,369,000	$12,275,821	<$1,093,179>
584	$7,021,000	$6,447,498	<$573,502>
MWC-BG			
588	$6,798,000	$6,414,265	<$383,735>
593	$28,227,000	$26,632,125	<$1,594,875>
594	$9,067,000	$8,555,168	<$511,832>
595	$1,619,000	$1,528,459	<$90,541>
596	$1,538,000	$1,452,919	<$85,081>
MWC-EW			
583	$30,000	$27,616	<$2,384>
584	$29,000	$26,260	<$2,740>
588	$7,299,000	$6,782,582	<$516,418>
592	$2,000	$2,201	$201
593	$151,000	$140,486	<$10,514>
594	$94,000	$87,356	<$6,644>
598	$306,000	$284,889	<$21,111>
MWC-GA			
583	$823,000	$706,404	<$116,596>
588	$1,253,000	$1,074,339	<$178,661>
593	$17,112,000	$14,671,106	<$2,440,894>
MWC-HN			
593	$126,857,000	$118,122,337,	<$8,734,663>
MWC-BA			
583	$391,000	$378,944	<$12,056>
588	$21,391,000	$20,804,720	<$586,279>
MWC-FM			
588	$8,881,000	$6,076,811	<$2,804,189>
MWC-DF			
584	$11,676,000	$11,072,690	<$603,310>
MWC-GF			
588	$355,000	$307,554	<$47,446>

III. DISCUSSION AND ANALYSIS

Customer Service Costs, PG&E-3

Administrative and Support Costs, PG&E-4

A. <u>Field Service– MWC DD</u>

ORA's forecast of $54.6 million in total expenses for MWC DD, Field Service, for the electric and gas distribution systems is the same as PG&E's TY 2003 forecast. However, as fully addressed in Chapter 7 of this report, ORA recommends redistributing the TY 2003 forecast so that it reflects an increase of $2,000,000 million for the electric distribution system and decrease by the same amount for the gas distribution system in TY 2003. ORA's 2003 forecast is $15.7 million for Electric Distribution and $38.9 million for Gas Distribution.

Table 6-16
MWC DD, Field Service
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
DD for the Electric Distribution System	$13,300,000	$15,300,000	<$2,000,000>	15.0%

B. <u>Electric Transactions Administration</u>

PG&E's Gas and Electric Supply (G&ES) organization has purview over the administration of electric supply for distribution customers. This function is called Electric Transaction Administration and includes procuring electricity under contracts with qualifying facilities and under power purchase agreements, managing PG&E's retained generation portfolio, and procuring electricity from the market.[53]

PG&E asserts that in order to fulfill its obligations in TY 2003, given its new legislative and regulatory mandates for procuring electricity supplies, it will require an additional 29 full-time-equivalent (FTE) positions at a

forecast cost of $3,500,000.[54] ORA recommends that expenses for an additional 18 FTEs be adopted and that PG&E's TY 2003 forecast be adjusted from $3,500,000 to $ 2,172,414 a difference of $1,327,586 or a decrease of 37.9%. ORA recommends that this adjustment be equally allocated to all of the MWCs associated with Electric Transactions Administration.[55]

Table 6-17

MWCs For Electric Transaction Administration
(In Nominal Dollars)

MWC	PG&E	ORA	PG&E> ORA	% Difference
AB	$3,030,000	$2,808,736	$221,264	7.3%
CT	$4,263,000	$4,041,736	$221,264	5.2%
FB	$3,823,000	$3,601,736	$221,264	5.8%
FR	$7,231,000	$7,009,736	$221,264	3.1%
HJ	$1,827,000	$1,605,736	$221,264	12.1%
HL	$1,890,000	$1,668,736	$221,264	11.7%
Total	$22,064,000	$20,736,414	$1,327,586	6.0%

ORA understands that PG&E does have new and complex responsibilities for procuring and managing electric supplies for its distribution customers.[56] This is evidenced by a steadily increasing head count in Electric Transaction Administration from 2000 to 2002. However, ORA recommends that 18 of the 29 FTE positions that PG&E requested be funded in rates for TY 2003.

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[53] PG&E-4, p. 15-1.

[54] Ibid., p. 15-16.

[55] The Electric Transaction Administration function is comprised of the following MWCs: AB (Support), CT (Accounting and Managing Electric Supply), FB (Maintain Computer Systems), FR (TRBAA, QF and ID), HJ (Generation Portfolio Management Fossil), and HL (Generation Portfolio Management Hydro). However, in DR-ORA-343-001, PG&E asserts that the requested 29 FTEs for TY 2003 cannot be apportioned to individual MWCs within the Electric Transactions Administration program.

[56] PG&E-4, p. 15-2 and DR-ORA-343-002.

The end-of-year 2002 headcount for Electric Transactions Administration was 98 FTEs, which is 7 more than the 91 FTEs reported in the testimony for March 2001.[57] ORA's recommendation for funding for 18 FTEs (out of 29 FTEs requested) is comprised of the 7 FTEs hired as of end-of-year 2002, plus additional 11 FTEs. The additional 11 FTEs is derived by taking one-half of the remaining personnel that PG&E, or 22 FTEs (29 FTEs requested less the 7 FTEs already hired). If PG&E hires additional 11 FTEs these personnel in TY 2003 there would be a total of 109 FTEs in this organization. This should provide sufficient TY 2003 funding for PG&E to meet its procurement responsibilities. Additionally, PG&E will benefit from funding the requested FTEs for a full year even if hiring for the requested positions occurs later in the year.

C. Summary of ORA Adjustments

ORA proposes the following adjustments for the MWCs presented by PG&E for support functions for the distribution system (Exhibits PG&E-3 and PG&E-4). Table 6-18 summarizes both MWC and FERC forecasts for TY 2003 and then states ORA's recommended adjustment in FERC account format adjusted into Base Year 2000 dollars. This last step allows for ORA's forecast to be input into the Results of Operation Model and allows for comparisons in the traditional general rate case methodology.

[57] PG&E-4, p. 15-9 and DR-ORA-343-001.

Table 6-18

Summary of ORA's MWC Adjustments by FERC Account

PG&E-3 and PG&E-4

(In Base Year 2000 Dollars)

	PG&E's 2003 Forecast	ORA's 2003 Forecast	PG&E>ORA
MWC-DD			
587	$12,665,000	$14,512,443	<$1,837,443>
MWC-AB			
557	$2,104,000	$1,952,207	<$151,792>
MWC-CT			
557	$3,159,000	$3,029,976	<$129,023>
MWC-FB			
557	$2,840,000	$2,672,903	<$167,096>
MWC-FR			
557	$5,498,000	$5,322,961	<$175,038>
MWC-HJ			
557	$1,385,000	$1,215,663	<$169,336>
MWC-HL			
557	$1,283,000	$1,219,852	<$63,147>

III. CONCLUSIONS

For the reasons addressed above ORA recommends that the Commission adopt its proposals with respect to O&M expenses for TY 2003. The total adjustment based on MWCs in PG&E-2 and reported in SAP nominal dollars for TY 2003 is $24,200,000 or a 5.5% decrease compared to PG&E's request. For expenses that PG&E characterizes as Customer Service Expense (PG&E-3), ORA recommends an increase of $2,000,000 for electric distribution system related expenses, which is balanced by a recommended decrease of $2,000,000 for the gas distribution system.[58] For the expenses that PG&E characterizes as Support Costs

[58] See Chapter 7 of this Report, which presents ORA's analysis of PG&E's Gas Distribution System O&M expenses.

for the Electric Distribution System (PG&E-4), ORA recommends an adjustment of $1,327,586 or a decrease of 6.0% that is allocated equally to all of the MWCs associated with Electric Transactions Administration.

Table 6-19 presents a summary and comparison of ORA's proposed adjustments and PG&E's TY 2003 request in terms of FERC accounts. Table 6-19 allows a comparison of PG&E's requested O&M expense levels and ORA's adjusted O&M expense levels in constant dollars.

Table 6-19

Comparison of PG&E and ORA TY 2003 Forecasts by FERC Account[59]

(In Thousands of Base Year 2000 Dollars)

FERC Account	Description	PG&E Forecast	ORA Forecast	PG&E> ORA
582	Station Expenses	$4,456	$4,456	$0
583	Overhead Line Expenses	$15,095	$13,871	<$1,224>
584	Underground Line Expenses	$18,725	$17,545	<$1,180>
585	Street Lighting/Signal Expenses	$0	$0	$0
586	Meter Expenses	$2,050	$2,050	$0
587	Customer Installation Expenses	$14,090	$15,937	$1,847
588	Miscellaneous Distribution Expenses	$92,599	$88,082	<$4,517>
TOTAL Operations Expenses		$147,015	$140,569	<$5,074>
591	Maintenance of Structures	$582	$582	$0
592	Maintenance of Station Equipment	$16,260	$16,260	$0.2
593	Maintenance of Overhead Lines	$195,970	$183,189	<$12,781>
594	Maintenance of Underground Lines	$19,233	$18,715	<$518>
595	Maintenance of Line Transformers	$5,974	$5,883	<$91>
596	Street Lighting and Signal Systems	$4,107	$4,022	<$85>
597	Maintenance of Meters	$11,770	$11,770	$0
598	Miscellaneous Distribution Plant	$403	$382	<$21>
TOTAL Maintenance Expenses		$254,300	$243,245	<$13,495>
TOTAL O&M Expenses		$401,316	$383,814	<$18,570>

[59] PG&E-6, Chapter 2 Workpapers, p. 2-6, and ORA Tables 6-15 and 6-18.

CHAPTER 7

GAS DISTRIBUTION

OPERATIONS AND MAINTENANCE EXPENSES

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) requests Commission authorization for the operations and maintenance (O&M) expenses required to operate and maintain its gas distribution system for test year 2003. The company sets forth its request in Exhibit PG&E-2, Chapter 3 "Customer Requested Construction," Chapter 10 "Meter Purchases and Maintenance," Chapter 12 " Electric Engineering, Planning and Mapping," Chapter 13 " Gas Distribution Operations," PG&E-3, Chapter 4 "Field Service and Dispatch," Chapter 5 "Read and Investigate Meters," Chapter 9 " Other Customer Service Activities," PG&E-4, Chapter 8 " Utility Operations Support," Chapter 11 "Purchasing Department," Chapter 13 "Environmental Program," PG&E-5, Chapter 9 " Other Information Technology Costs," and PG&E-6, Chapter 3 "Gas Distribution Operations and Maintenance Expenses." This chapter presents ORA's analysis of the company's proposal and recommendations in response to all of the above-mentioned exhibits and corresponding chapters.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations. Section III presents ORA's analysis of Major Work Categories[1] AK, AR, CG, CM, CR, DD, DE, DF, DG, DN, ES, EW, EX, EY, FG, FH, FI, FM, GF, GG, GM and CV (Gas Procurement Administration) and the corresponding Federal Energy Regulatory Commission (FERC) Accounts 871 to

[1] Major Work Categories will be further discussed in details in Section III of this chapter.

881 (for operations) and Accounts 885 to 894 (for maintenance), and Account number 807.5 (for other purchased gas expenses) within each MWC and in nominal SAP dollars[2]. Section IV presents ORA's analysis of PG&E's request and support for ORA's forecasts and recommendations by FERC Accounts and in 2000 dollars. Finally, Section V provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

PG&E is requesting $133 million (in nominal 2003 dollars) in operating expenses for Gas Distribution O&M and $4.1 million in expenses for gas procurement. Previously PG&E had requested approximately $ 2 million less, or $130.9 million, in its Notice of Intent.

In constant 2000 dollars, PG&E's request translates to $123.3 million with $83.3 million for operations and $40 million for maintenance. This amount is 13 percent lower than the $141 million of Gas Distribution O&M expenses that the Commission adopted in the 1999 GRC. However, PG&E's request is 5.5 percent higher than the 2000 recorded adjusted amount of $116.8 million.[3]

The corresponding ORA estimate for Gas Distribution O& M expenses is $113.9 million with $ 77.2 million for operations and $ 36.6 million for maintenance. As for gas procurement expenses, PG&E is requesting $4.1 million for 2003. This translates to $3.3 million, in 2000 dollars, in expenses for gas procurement administration. ORA accepts PG&E's forecast of gas procurement expenses.

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[2] SAP dollars are dollars stated in current year (or nominal) and include certain labor-driven adders such as employee benefits and payroll taxes. PG&E's financial and management accounting system uses software developed by SAP AG and is colloquially referred to at PG&E as the SAP system. The SAP system data are recorded using a chart of accounts called Major Work Category and the dollars that are tracked in these accounts are referred to as SAP dollars.

[3] PG&E-6, p. 3-1:2.

PG&E cites the following reasons for the decrease in its 2003 estimate for Gas Distribution O&M expenses from the 1999 GRC authorized amount[4]:

- Significant reduction in gas customer field service costs due to centralized program management and reduced overtime;
- Lower expenses as a result of transitioning from traditional research and development to technology demonstration projects;
- Reduction in information technology expenses; and
- Reduction in maintenance expenses including cathodic protection and leak repair due to centralized program management.

ORA notes that in 1999, PG&E's actual Gas Distribution O&M expenses were $117.3 million (in 2000 dollars)—17 % lower than the Commission authorized amount of $141 million (in 2000 dollars).

ORA has reviewed and analyzed PG&E's Application. ORA finds many of PG&E's O&M requests to be reasonable. ORA agrees with PG&E's request for expenses in MWCs AK, AR, CG, CM, CR, DD, DE, DN, ES, EW, FG, GG, and CV. However, for some of PG&E's work activities in MWCs DF, DG, EX, EY, FH, FI, FM, GF, and GM, ORA finds that its approach is more appropriate because ORA incorporated PG&E's recent and historical actual expenses to develop its forecast for 2003. PG&E's overall Gas Distribution O&M expenses have been decreasing between 1997 and 2001 from $162.1 million to $104.9 million.[5] Also, the Commission authorized 1999 PG&E Gas Distribution O&M expenses, by FERC Accounts, were from 1% to 24% higher than what the company has actually been spending.[6] (See Attachment 1 for a comparison of PG&E's actual and Commission authorized O&M Gas Distribution expenses for the period 1990 to

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[4] Ibid. p. 3:1-3.

[5] PG&E data response to ORA DR 195, Q. 4a.

[6] PG&E data response to ORA DR 195, Q. 4a.

2001 by FERC Accounts.) ORA recommends an adjustment of $9.8 million, in nominal dollars, ($9.1 million, in 2000 dollars) to PG&E's 2003 forecast for Gas Distribution O&M expenses bringing the total to $123.3 million instead of $133 million as PG&E had forecasted. ORA notes that $2 million of ORA's total adjustment is derived from ORA's recommendation of redistributing PG&E's Electric and Gas Distribution allocations for MWC DD in 2003 to be consistent with 2002 actual expenses and is not due to any difference with PG&E's forecast for this MWC. This will be further discussed in ORA's analysis of MWC DD below. ORA finds PG&E's request of $4.1 million in gas procurement expenses to be reasonable and accepts PG&E's 2003 forecast for MWC CV.

Table 7-1 presents the differences between ORA's and PG&E's projections for Test Year 2003 expenses and Table 7-2 presents PG&E's and ORA's 2003 forecast by FERC accounts and in 2000 dollars.

Table 7-1

DIFFERENCES BETWEEN ORA AND PG&E 2003 FORECAST GAS DISTRIBUTION O&M EXPENSES

(In Thousands of Nominal Dollars)				
	PG&E	ORA	PG&E>ORA	Percent
Total O&M	133,038	123,252	9,786	7.4%
(In Thousands of 2000 Dollars)				
Total O&M	123,299	113,892	9,119	7.4%
(In Thousands of Nominal Dollars)				
Gas Procurement	4,123	4,123	0	0%

Table 7-2
SUMMARY OF PG&E'S AND ORA'S 2003 FORECAST BY FERC ACCOUNTS
(In Thousands of 2000 Dollars)

Accounts	Description	PG&E	ORA	PG&E> ORA
871	Load Dispatching	240	240	**0**
874	Mains and Services	13,903	13,525	**378**
875	Measuring & Reg. Station Gen.	953	953	**0**
876	Measuring & Reg. Station Indus.	1,342	1,257	**85**
878	Meter & House Regulators	3,672	3,443	**229**
879	Customer Installation	44,828	40,958	**3,870**
880	Other	18,333	16,869	**1,464**
Operation Total		83,272	77,245	**6,027**
886	Structures & Improvements	0	0	**0**
887	Mains	14,847	13,498	**1,349**
889	Measuring & Reg. Station Gen.	3,259	2,859	**400**
890	Measuring & Reg. Station Indus.	3,582	3,355	**227**
892	Services	8,622	8,158	**464**
893	Meters & House Regulators	7,050	6,416	**634**
894	Other Equipment	2,380	2361	**19**
Maintenance Total		40,027	36,647	**3,093**
Gas Distribution Expense Total		**123,299**	**113,892**	**9,119**

III. DISCUSSION/ANALYSIS—GAS DISTRIBUTION O&M EXPENSES BY MAJOR WORK CATEGORIES

According to PG&E, the company now organizes its responsibilities functionally by major program areas rather than geographically as before. It also now uses the SAP system, which uses Major Work Categories (MWCs), to manage work activities and associated costs necessary to provide service to its customers. In this Application, all of the information regarding the company's operations and costs are organized by Major Work Categories. These costs are stated in nominal dollars and include certain labor-driven adders such as employee benefits and

payroll taxes. These costs are also referred to as "SAP dollars."[7] The labor adders for employee benefits and payroll taxes which are included in the MWC estimates are not recorded in the traditional O&M FERC Accounts and instead are captured in FERC Accounts 926 and 408, respectively. Since the Commission sets rates based on FERC Accounts rather than MWCs, these labor adders must be removed to show O&M costs on a FERC account basis. The FERC Account basis O&M forecasts are shown at the end of each chapter of Exhibit PG&E-2 and are aggregated into an overall O&M forecast in Exhibit PG&E-6.

PG&E is using MWCs to show its distribution revenue requirement request from the "bottom-up" approach. In other words, PG&E's 2002 and 2003 O&M forecasts are based on recorded number of units of work and unit costs in 2000 and 2001 tracked by MWCs. PG&E then "translates" the expenses from these MWCs to corresponding FERC Accounts in a table within each chapter, first in nominal dollars and then in 2000 constant dollars. PG&E explains the translation process as, "assignment of amounts to electric and Gas Distribution O&M expense FERC Accounts for each MWC was based on an analysis of the work to be performed and an assessment of the appropriate account to which the costs of the work should be charged."[8]

ORA does not dispute the manner in which PG&E manages its Gas Distribution expenses or the assignments to FERC Accounts and will present its analysis and discussion by MWC and by FERC Accounts mirroring PG&E's O&M expense Exhibits PG&E-2 to 6. In this section, ORA will first discuss its analysis and recommendations regarding MWCs AK, AR, CG, CM, CR, DD, DE, DF, DG, DN, ES, EW, EX, EY, FG, FH, FI, FM, GF, GG, GM and CV, and by FERC Accounts and by FERC dollars without certain labor-driven adders such as

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[7] PG&E-1, p. 4-4:7

[8] PG&E data response to ORA DR 100, Q. 1.

employee benefits and payroll taxes. All expenses discussed in this section will be in nominal dollars unless otherwise stated. Section IV presents a summary of ORA's recommendations, where ORA differs from PG&E, including a table showing the adjustments, by MWCs and by FERC Accounts. The ORA recommendations are de-escalated to base year 2000 dollars consistent with the method used by PG&E.

ORA reviewed PG&E's testimony and requested information regarding each of the program areas and the respective MWCs. ORA also analyzed PG&E's historical Gas Distribution O&M expenses by FERC Accounts and by MWCs. For the FERC Accounts, PG&E provided ORA 1990 through 2002 recorded data for its analysis. As for the MWCs, PG&E stated that because its SAP accounting system was not implemented until 1996, it was only able to provide ORA with 1997 through 2002 recorded data by MWCs for its analysis. However, not all the Gas Distribution O&M expense MWCs were created in 1996 and not all MWCs created in 1996 were continued through 2002. PG&E acknowledges that as work activities included in a MWC change over time, the costs recorded by MWC may be shifted from one MWC to another or PG&E may create a new MWC altogether. Nevertheless, PG&E assures ORA that its SAP system has the capability to "rearrange" the historical recorded costs to conform to the "new" MWC definition and can reflect current activities in a new MWC as if the definition had been in effect since 1996.[9] The history of Major Work Categories provided by PG&E shows most MWCs were developed in 1996 and 1997 and have remained constant through 2002, with the exception of MWC GM, GF, and GG, which were created in 1998.

ORA's analysis of the individual Gas Distribution O&M expenses MWCs: AK, AR, CG, CM, CR, DD, DE, DF, DG, DN, ES, EW, EX, EY, FG, FH, FI, FM,

[9] PG&E data response to ORA DR 214, Q. 1.

GF, GG, GM and CV are discussed below. ORA analyzes each MWC and the corresponding expenses in each FERC Account within these MWCs. When possible, ORA will adjust the expenses directly by FERC Accounts. However, when ORA adjusts the overall expenses of a MWC in this chapter, ORA will translate the overall MWC adjustments to the corresponding O&M FERC Accounts(s) based on the allocation percentage of each Gas Distribution FERC Account in a particular MWC. Moreover, the adjustments and ORA's subsequent recommendations will be without certain labor-driven adders such as employee benefits and payroll taxes. A summary of ORA's adjustments to each affected MWC is set forth in Table 7-15 at the end of this chapter.

A. MWC AK, Environmental Operations FERC Accounts 880 and 887

MWC AK includes expenses for routine environmental work for the utility and includes labor costs of environmental professionals and facility personnel who perform environmental compliance tasks, such as hazardous waste inspections, record keeping, preparation of Spill Prevention Countermeasures and Control Plans, Hazardous Material Business Plans, and other regulatory required environmental plans and filings. It also includes the cost associated with the development of environmental training, compliance support, and permit fees[10].

PG&E is requesting $7.9 million in expenses for activities done under MWC AK. Of this total, there is zero dollars in its request specific to Gas Distribution O&M expenses. ORA has no adjustment to this MWC specific to Gas Distribution expenses.

[10] PG&E-4, p. 13-7.

B. MWC AR, Read and Investigate Meters FERC Account 875

MWC AR includes expenses related to the 820 meter readers who read more than 8 million meters each month, and the 26 employees who read large industrial and commercial interval meters.

PG&E is requesting $92 million in expenses for 2003. Of this total, PG&E is requesting $61,000 in specific Gas Distribution expenses, FERC Account 875. PG&E's 2003 expense forecast for MWC AR activities is based on recorded 2000 expenditures, adjusted to remove all one time and non-recurring expenses.

PG&E's actual expenses for FERC Account 875 in 2000 and 2001 were $56,000 and $51,000 respectively. ORA finds PG&E's request of $61,000 for Gas Distribution expenses in 2003 to be reasonable and accepts its forecast.

C. MWC CG, Other Customer Service Activities FERC Account 894

MWC CG tracks O&M expenses associated with Low Emission Vehicles (LEVs). LEVs are alternative fuel vehicles, which are part of PG&E's fleet. Presently, the Energy Policy Act requires 90 percent of all light-duty vehicles purchased for the utility's fleet must be capable of using an alternative fuel—either natural gas or electricity[11].

PG&E is requesting $2.9 million for MWC CG expenses in 2003. Of this total, $1.8 million of this request is directly allocated to Gas Distribution FERC Account 894. PG&E states that the expense forecast reflects costs for operating and maintaining the existing network of fueling stations, as well as

[11] PG&E-3, p. 10-2.

the cost to operate and maintain new station additions[12]. Table 7-3 below shows recorded expenses of MWC CG for the years 2000, 2001 and 2002 and forecast for 2003. PG&E's 2002 actual expenses for MWC CG are $1.8million. This is $68,000 above the total 2002 forecast of $1.75 million.

Table 7-3
MWC CG, CLEAN AIR TRANSPORTATION
(In Thousands of Nominal Dollars)

	PG&E's Recorded and Forecast Expenses for MWC CG					ORA
	Recorded			Forecast		Forecast
MWC	2000	2001	2002	2002	2003	2003
CG	1,882	2,161	1,820	1,752	2,950	2,950

The O&M expenses under MWC CG are dependent on the capital expenditure forecast for "mandatory" LEVs, or the number of LEVs operated by PG&E and the number of vehicles the Fleet Services Department obtains. Since ORA accepts PG&E's forecast of capital expenditure associated with LEV's, (See Chapter 15, Common, General and Intangible Plant) ORA also accepts PG&E's 2003 forecast of LEV related expenses in MWC CG.

D. MWC CM, Gas Load Dispatch FERC Accounts 871 and 894

The major activity in MWC CM is the remote monitoring and control of the flow of gas by system gas control operators located at PG&E's three gas control centers. Operators use a Supervisory Control and Data Acquisition (SCADA) system to monitor and control various aspects of the gas distribution system to ensure the system is operating safely and efficiently and to detect failures in the system. Although MWC CM encompasses both gas transmission and distribution load dispatching

[12] PG&E-3, p. 10-6.

because gas control room operators uses SCADA for both systems, only a small part of MWC CM expenses are Gas Distribution expenses.

PG&E is requesting $349,000 in expenses for MWC CM in 2003. Of this total, the company is forecasting $262,000 for Gas Distribution FERC Account 871 and $24,000 for FERC Account 894. See Table 7-4 below for a summary of MWC CM expenses.

Table 7-4
MWC CM, Gas Load Dispatch
(000's Nominal Dollars)

	PG&E's Recorded and Forecast Expenses					ORA
	Recorded			Forecast		Forecast
FERC	2000	2001	2002	2002	2003	2003
	270	260	271	257	262	262
	19	17	20	24	24	24
	289	**277**	**291**	**281**	**286**	**286**

The 2002 actual expenses are $291,000 and PG&E's 2002 forecast is $281,000 for FERC Accounts 871 and 894. It appears that the company's 2002 actual expenses closely match with its forecast for gas load dispatch. For 2003, PG&E states that it does not expect the work activities to change and will continue on a flat staffing plan. ORA accepts PG&E's 2003 forecast for Accounts 871 and 894 of MWC CM.

E. <u>MWC CR, Waste Disposal and Transportation FERC Account 880</u>

MWC CR includes routine expenses for transportation and disposal of hazardous and other regulated wastes in accordance with federal and state laws and regulations.

PG&E is requesting $1.5 million in total expenses for MWC CR in its 2003 forecast. Of this total, the company allocated $12,000 to Gas Distribution expenses FERC Account 880.

ORA accepts PG&E's 2002 forecast of Gas Distribution expenses for FERC Account 880 in MWC CR.

F. MWC DD, Customer Service Dispatch FERC Account 879

The work activities in MWC DD include responding to emergencies, initiating and terminating gas and electric service, adjusting appliances and checking them for safety, disconnecting and reconnecting service in connection with fumigation activities, responding to energy cost inquiries to verify accuracy of meter readings and to determine energy usage capabilities of customers' appliances, and relighting approximately 195,000 pilot lights during the heating season (October 1 through December 31).[13]

In 2000, the costs of MWC DD activities were $63.6 million. In 2001, the costs associated with these activities were $61.8 million. According to PG&E, the cost reduction was due to unfilled job vacancies throughout the year and improved cost management measures. PG&E is requesting $66 million in MWC DD expenses for 2003. Of this total, $40 million is allocated to Gas Distribution FERC Account 879 and $13.7 million is allocated to Electric Distribution FERC Account 587. PG&E's 2003 forecast does not show any increase in work activities compared to its 2002 forecast. However, PG&E is requesting an increase of $1.9 million above its 2002 forecast for labor and non-labor escalations.

ORA finds PG&E's overall forecast for MWC DD to be reasonable and accepts the company's 2003 forecast. However, PG&E's actual allocation of 2002 actual recorded expenses to Electric and Gas Distribution differ from the 2002 and 2003 forecasts. Therefore, ORA recommends reallocating the 2003 forecast so that it more closely reflects the 2002 actual

[13] PG&E-3, p. 4-5.

expenses. PG&E's 2002 actual expenses were $15.3 million for Electric Distribution and $38.1 million for Gas Distribution. In PG&E's 2002 forecast, the company allocated $13.3 million for Electric Distribution and $40 million for Gas Distribution. PG&E's 2002 actual expenses were $2 million higher than the company had previously forecasted for Electric Distribution and $2 million lower than what the company had forecasted for Gas Distribution.

ORA recommends redistributing the 2003 forecast so that it reflects an increase of $2 million for Electric Distribution and a decrease by the same amount for Gas Distribution in 2003. ORA's 2003 forecast is $15.7 million for Electric Distribution and $38.9 million for Gas Distribution. ORA's forecast of $54.6 million in total expenses for Electric and Gas Distribution is the same as PG&E's 2003 forecast.

See Table 7-5 below for a summary of PG&E's and ORA's 2003 forecasts for MWC DD.

Table 7-5
MWC DD, FIELD SERVICE
(In Thousand of Nominal Dollars)

FERC Allocation	**PG&E's 2003 Forecast**	**ORA's 2003 Forecast**	**PG&E> ORA**
587	**13,711**	**15,711**	**(2,000)**
879	**40,933**	**38,933**	**2,000**
Taxes and Benefits	**11,384**		**0**
TOTAL	**66,028**	**66,028**	**0**

G. MWC DE, Leak Survey FERC Accounts 874 and 880

MWC DE tracks expenses required for PG&E to survey its distribution system for leaks. There are two basic types of leak surveys that PG&E must perform, the required leak surveys and the special leak surveys.

Required leak surveys are performed every one, three, or five years and special leak surveys are required for scheduled leak rechecks, after a leak is repaired, before and after heavy construction is performed near PG&E's facilities, after a major natural event like an earthquake or landslide, and other situations not covered in the scheduled leak surveys.

In 2003, PG&E is forecasting an increase in the number of miles surveyed from 18,548 to 19,254 due to additional miles of main and services installed. The 2003 forecast for MWC DE is $5.7 million. Of this total, $4.5 million is allocated to FERC Account 874 and $236 thousand to FERC Account 880 bringing the total Gas Distribution expenses to $4.8 million.

PG&E's 2002 actual recorded expenses for MWC DE are $5.7 million compared to its forecast of $5.6 million. PG&E's 5-year average of expenses between 1998 and 2002 for MWC DE is $5.8 million. See Table 7-6 below for a summary of recorded and forecast expenses for FERC Accounts 874 and 880. ORA finds PG&E's request for Gas Distribution expenses of MWC DE to be reasonable and accepts PG&E's 2003 forecast.

Table 7-6
MWC DE, LEAK SURVEY
(In Thousand of Nominal Dollars)

	PG&E's 1997-2003 Expenses (In Thousands of Nominal Dollars)							ORA
	Recorded						Forecast	Forecast
MWC	1997	1998	1999	2000	2001	2002	2003	2003
DE	6,682	6,254	5,556	5,972	5,857	5,651	5,700	5,700

H. MWC DF, Mark & Locate FERC Account 874

The basic activity of MWC DF is to notify builders, contractors, and others planning to excavate with information about the location of PG&E's underground facilities. PG&E belongs to two regional one-call systems commonly referred to as "USA" which stands for Underground Service Alert. USA notifications, called "tags" are transmitted electronically to PG&E and are processed by the company's ticket handling software, which sends the tag first to mapping personnel. If mapping personnel determine that PG&E's facilities maybe involved, they prepare a "ticket" package for maintenance personnel consisting of the USA tag and copies of facility maps. A PG&E's maintenance worker then visits the site, locates any pipes or wires, and paints a mark on the ground showing the horizontal path of any such facility detected.[14] Additional expenses in this MWC also include fees for membership in the USA system and the costs of its Outreach Program to increase public awareness and the cost of damage prevention presentations to local public works offices.

PG&E states that over the past 9 years, the number of USA tags received by the company has increased on average by 9.1% per year. PG&E

[14] PG&E-2, p. 13-17.

projects moderate increases of 5 percent in 2002 and 7 percent in 2003. To support these increases, PG&E is requesting $26.1 million in expenses for MWC DF in 2003. Of this total, $9.3 million is allocated to Gas Distribution FERC Account 874.

ORA finds PG&E's 2003 request for increased funding to be excessive given historical spending levels and the fact that the company forecasts a lower than historic increase in the number of tags in 2003.[15] Moreover, actual recorded 2002 expenses for MWC DF were $800,000 below the forecast of $24.9 million although PG&E processed more tags than expected. See Table 7-6 below for a summary of historical and forecast expenses for MWC DF.

PG&E's 2003 forecast includes an increase of 7% in the number of USA tags and $6,000 in increases for USA membership cost. ORA finds that the level of spending for the past 6 years does not correlate with the level of work activity for this MWC. For example, PG&E's expenses in 1998 were $7.5 million less than 1997 but the company processed an increase of 10.8% in USA tags. The following year, PG&E's expenses were increased only by $700,000, but the company processed 12% more tags than 1998. In 2000, the company processed 13.1% USA tags above 1999 and the expenses were $10.6 million higher.

Due to the fluctuations in expenses and the number of tags performed each year, ORA recommends using an average percentage of the increase in the number tags for the most recent years, 2001 and 2002, to determine the 2003 forecast. Additionally, ORA recommends using the 2002 unit cost as the forecasted unit cost for each tag performed in 2003. As such, ORA recommends a 3% increase (or 17,602 tags) in the number of tags performed

[15] PG&E-2, p. 13:20.

in 2003 in contrast to PG&E's forecast of 7% increase. Using the 2002 unit cost of $45 per tag, ORA's forecast yields a total of $24.8 million in total expenses for MWC DF compared to PG&E's forecast of $26.1 million. This amount is $1.4 million lower than PG&E's 2003 forecast. This adjustment translates to $410,000 less than PG&E's forecast for Gas Distribution FERC Account 874 and $714,000 less for Electric Distribution FERC Account 584. See Table 7-7 below for a breakdown of PG&E's MWC DF expenses and the number of USA tags processed by year, for the years 1997-2002 and the differences between ORA's and PG&E's 2003 forecast.

Table 7-7
MWC DF, MARK AND LOCATE
(In Thousand of Nominal Dollars)

PG&E's 1997-2003 Expenses (In Thousands of Nominal Dollars)							ORA	PG&E> ORA
Recorded						Forecast	Forecast	
1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2003**	**2003**
20,220	12,584	13,301	23,928	23,708	24,101	26,146	24,795	1,351
Number of USA Tags by Year								
356,371	394,969	442,325	500,109	508,237	533,401	570,739	551,003	19,736
% Of Number of Tags Increased				**1.6%**	**5%**	**7%**	**3.3%**	**3.7%**
BY FERC ACCOUNT								
Gas Distribution 874						9,336	8,926	410
Electric Distribution 584						12,616	11,902	714

I. MWC DG, Cathodic Protection FERC Accounts 880 and 887

MWC DG tracks the expenses of PG&E's Cathodic Protection (CP) Program. According to PG&E, cathodic protection is necessary because buried metal pipes have a natural tendency to corrode and this can cause

leaks and other potential safety hazards if it is not prevented.[16] The work activities of this MWC include the continual monitoring of the CP system to ensure that adequate levels of current are maintained, the Cathodic Protection Resurvey Program to ensure all applicable pipe is under cathodic protection, and troubleshooting areas found to be below CP protection levels.

PG&E's 2003 request of $7.3 million for expenses incurred under MWC DG is spread among the following areas: (1) CP Monitoring, (2) CP Resurvey, (3) CP Troubleshoot, and (4) CP Isolated Services. See Table 7-8 for a breakdown of the expenses for each of these areas.

Table 7-8
MWC DG, CATHODIC PROTECTION
(Only "Dollars" Column In Thousands of Nominal Dollars)

PG&E's 2003 Forecast				**ORA's 2003 Forecast**	**PG&E> ORA**
Item	**Units**	**Dollars**	**Dollars**	**Dollars**	**Dollars**
General	N/A	575	575	575	0
CP Monitoring	61,098	1,642	1,642	1,342	300
CP Resurvey	609	1,107	1,107	1,107	0
CP Troubleshoot	3,069	3,015	3,015	3,015	0
CP Isolated Services	30,963	$30/unit	929	0	929
Total MWC DG			**7,269**	6,041	1,229

ORA reviewed PG&E's testimony and analyzed PG&E's responses to ORA's data requests. ORA finds PG&E's 2003 forecast to be excessive and recommends the following adjustments: (1) an adjustment of $300,000 for the expenses associated with the CP remote monitoring project, and (2) an adjustment of $929,000 for the CP Isolated Services.

PG&E is initiating a program to remotely monitor pipe-to-soil potential reads and rectifier output to ensure proper levels of CP are

maintained. As of December 2002, the company had not signed a contract with any vendor and PG&E does not expect CP remote monitoring units will be operative until December 31, 2003.[17] Since the CP remote units will not be operative until December 31, 2003, ORA recommends adjusting the expenses associated with the remote monitoring projects from the 2003 forecast. This results in an adjustment of $300,000.

ORA also finds PG&E request for additional funding to protect services found isolated from PG&E's system to be inappropriate because it represents deferred maintenance. PG&E states that it has determined that many buried steel services may be isolated from the CP systems as a result of previous reconstruction and projects, and that 30,963 services will need CP protection. PG&E states that it recognizes that buried metal pipes have a natural tendency to corrode and cause leaks that could be potential safety hazards if not monitored and yet the company has allowed these services to be isolated from the systems. PG&E has been receiving on-going funding for the CP program to ensure that the pipes and services in its systems are CP protected. ORA notes that between 1997 and 2001, PG&E received authorized O&M expenses that, on average, were 16% higher than the company's actual expenses.[18] PG&E has allowed over 30,000 steel services to be isolated from the CP systems. PG&E should have been coordinating re-surveys of its system and taking appropriate steps along the way when reconstructing projects or installing new mains in order to avoid such a critical condition. PG&E needs to take immediate steps, without additional funding from ratepayers who have already paid for CP services over the years, to ensure that all services found within its CP systems are placed

[17] PG&E data response to ORA DR 105, Q. 5.

[18] See Attachment 1 of this Chapter.

under CP and then under a monitoring interval. This recommendation is an adjustment of $929,000 to PG&E's request.

ORA's total adjustment to PG&E's 2003 forecast for MWC DG is $1.2 million. Table 7-9 below shows the translation of the $1.2 million adjustments discussed above into FERC Accounts 880 and 887 using PG&E's allocation factors for 2003.[19]

Table 7-9
MWC DG, CATHODIC PROTECTION
ORA's ADJUSTMENTS TO FERC ACCOUNTS 880 and 887
(In Thousands of Nominal Dollars)

FERC Accts.	PG-E's 2003 Forecast	FERC Amounts As % of Total	ORA's Adjustments	**ORA 2003 Forecast**
880	363	6%	(61)	**302**
887	5,739	94%	(980)	**4,769**
Total FERC	6,102	84%	(1,032)	**5,070**
Total DG	7,270		(1,229)	**6,041**

J. MWC DN, Develop and Provide Training FERC Account 880

MWC DN tracks expenses of the Human Resources Learning Services group, which develops and provides technical gas training to PG&E's employees. Some examples of the training developed and provided are construction vehicle and equipment operation, steel and plastic pipe joining, corrosion control, and gas measurement and control.

PG&E's 2003 request for expenses in MWC DN is $755,000. Of this total, $650,000 is directly allocated to FERC Account 880. In 2002, PG&E's actual expenses for MWC DN were $643,000 although the company had forecast spending $1.3 million in training. ORA reviewed a listing of the training courses for Gas Distribution PG&E offered in 2002

[19] PG&E-2, p. 13-79

and forecast for 2003.[20] ORA finds PG&E's 2003 request for MWC DN Gas Distribution expenses to be reasonable and accepts PG&E's forecast.

K. MWC ES, Environmental Projects and Initiatives FERC Account 880

MWC ES includes expenses for clean up of residual pollution effects from PG&E operations on current or former company properties and third-party locations that cannot be recovered through the Commission's Hazardous Substance mechanism. MWC ES also includes costs to prepare property for sale and to conduct due diligence in connection with the sale.

PG&E is requesting $1 million in expenses for MWC ES. Of this total, $307,000 is directly charged to FERC Account 880. ORA finds PG&E's 2003 request for Gas Distribution expenses in MWC ES to be reasonable and accepts PG&E's forecast.

L. MWC EW, Work Requested by Others FERC Account 880

MWC EW includes expenses to relocate work that does not entail plant replacement and land right-of-way record research requested by third parties that cannot be charged to a specific project. According to PG&E, this account also tracks costs for reimbursable work that are offset by payments from customers and governmental agencies with cost-sharing agreements with PG&E. PG&E states that the relocation work of MWC EW is fairly constant year-to-year and projects its forecast expenses based on 2001 spending and estimated increase in work requests.

PG&E is requesting a total of $14.4 million in expenses for MWC in 2003, less $5.6 million for gas and electric reimbursable[21], resulting in a net

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[20] PG&E data response to ORA DR 232, Q. 17.

[21] This is money that customers pay PG&E for reimbursable work and is treated as a credit to this MWC. This amount will be credited to FERC Account 495 under Other Gas

request of $8.8 million. Of the total request, $3.8 million is allocated to Gas Distribution FERC Account 880.

For 2002, the company forecasts $14.1 million in expenses, with a net amount of $7.7 million, for MWC EW. Actual 2002 MWC EW expenses, net of reimbursable amounts, were $7.6 million. Actual 2002 expenses for Gas Distribution FERC Account 880 were $5.5 million with a net amount of $3.6 million. PG&E's workpapers show that the company expects expenses to be flat from 2002 to 2003.

ORA finds PG&E's 2003 request for Gas Distribution expenses in MWC EW to be reasonable and accepts PG&E's forecast.

M. MWC EX, Meter Protection FERC Account 880

MWC EX tracks expenses for work performed by PG&E's Meter Protection Program (MPP). In 1990, PG&E started this program to correct gas meter locations that do not conform to current company policies and standards and do not meet the requirements of federal pipeline safety regulations. The focus of the program is on meter locations that do not have adequate protection from damage by vehicles or have service or shutoff valves that are located inside buildings. [22]

In PG&E's Application, the company states that the current program's scope consists of 383,264 meter locations that need to be inspected and modified between 1990 and 2008. The company expects to complete the inspection of all remaining meter locations in 2002 and to focus the MPP program to performing corrective work in 2003.

Revenues for gas distribution and to FERC Accounts 454 and 456 under Rent from Electric Properties and Other Electric Revenues for electric distribution. See PG&E Data Response to ORA DR 40, Q. 3.

[22] PG&E-2, p. 13-61:62.

According to the Meter Protection Program, 2001 Annual Progress Report (MPP report) that PG&E submitted to the Commission's Utilities Safety Branch (USB), the company inspected a total of 359,475 meter locations between 1990 and 2001 at an average rate of 32,679 meter locations per year while also performing corrections as necessary. In Table 1 of this report, PG&E forecasted that it will inspect 37,001 meter locations but in its Application, the company forecasted that it would inspect all of the remaining 41,751 meter locations by the end of 2002 and will only be performing protections/corrections services in 2003. ORA bases its 2003 forecast on the MPP report because ORA finds that the MPP report is more reliable in tracking and forecasting the work activities under this MWC. The MPP report is provided to the Commission on an annual basis and is used by the Commission's USB to monitor the status of the MPP program.

Accordingly, ORA recommends the unit cost of $421 as stated in the MPP report and not $490.97 per site to correct or protect non-conforming meters as presented in PG&E's Application.[23] The unit cost of $421 per site also reflects the 2002 actual expenses of $1.4 million for the inspections and corrections done in 2002.[24]

Using the $421 as the unit cost per site protected and PG&E's forecast of 5,092 units of work, it follows that the total 2003 forecast for MWC EX is $2.1 million. This results in an adjustment of $400,000 to the overall expenses of MWC EX. Of this total adjustment, 84 percent or $342,000 should be adjusted from FERC Account 893 because this is

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[23] See PG&E's Gas Meter Protection Program, 2001 Annual Progress Report to the Utilities Safety Branch, CPUC, p. 2.

[24] ORA calculated that in 2002 the expenses for 37001 inspections at 10 per inspection were $370,000 and the expenses for the 2,614 corrections at $421 per corrections were $1.1 million. The sum of these two amounts equals $1.5 million and closely reflects the 2002 actual expenses of $1.4 million.

representative of the allocation percentage of Gas Distribution FERC Account 893 in MWC EX for 2003. See Table 7-10 below for a summary of PG&E's and ORA's forecast.

Table 7-10

MWC EX, METER PROTECTION
(In Thousands of Nominal Dollars)

PG&E's 2003 Forecast			ORA's 2003 Forecast		PG&E>ORA
Units	Unit Cost	Total	Unit Cost	Total	
5,092	490.97	2,500	421	2,100	400
FERC ALLOCATION					
893		2,106		1,769	337

N. MWC EY, Install Meters and Devices FERC Accounts 876, 878, 880, 890, and 893

MWC EY tracks expenses that cover electric metering, gas metering and electric and gas metering support. Only expenses related to gas metering are discussed below. Gas metering activities are composed of three main activities: (1) gas meter installations, (2) gas meter preventative maintenance, and (3) gas meter corrective maintenance.

PG&E's 2003 forecast of gas metering expenses for MWC EY is $17.9 million. The gas metering expenses make up 48% of the total expenses of $37.1 million for MWC EY in 2003. The 2003 forecast for gas metering expenses is approximately $2.3 million more than the 2002 forecast of $15.7 million for gas metering. [25] PG&E states that this increase is primarily caused by the installation of the electronic remote transmitting (ERT) devices, a new program that will start in 2003.[26] The only other change to PG&E's 2003 forecast is additional savings in the overall gas and

[25] PG&E-2, p. 10-9, Table 10-7.

[26] PG&E-2, p. 10-17.

electric metering unit cost. PG&E's forecast is based on its calculation of an overall unit cost for gas metering activities based on the expenses of MWC EY and the capital expenditures of MWC 74. PG&E forecasts that the company will spend a total of $37.5 million in expenses and capital expenditures for 3,986,658 gas meters in 2003. The $37.5 million for gas metering is made up of 48% in expenses from MWC EY, or $17.9 million, and 52% in capital expenditures from MWC 74 (which will be discussed in Chapter 16, Gas Distribution Plant) or $19.6 million.

PG&E's 2003 forecast of $9.42 per gas meter in service is derived by dividing the total amount of gas metering activities expenses, $37.5 million, by the total number of gas meters projected to be in service, or 3,986,658 gas meters. The 2003 unit cost represents an increase of $1, or 10%, over the 2002 forecast unit cost of $8.42 per unit. PG&E's workpapers do not show the derivation of this increase.

ORA recommends adjusting PG&E's 2003 unit cost to arrive at a more reasonable forecast for gas metering expenses. According to PG&E, the company plans to install 56,000 ERT devices on gas meters at about $60 per unit cost during 2003 and 2004, with about 50 percent being installed each year. This translates to PG&E installing 28,000 ERT devices in 2003 at $60 per unit for a total cost of $1.7 million. Since the primary reason for the $4.3 million increase in 2003 compared to the 2002 expense level is due to the installation of ERT devices, ORA recommends adding the $1.68 million of ERT expenses to the 2002 expenses of $33.3 million to derive the 2003 forecast. This approach would yield a total of $35 million in contrast to PG&E's forecast of $37.5 million for gas metering activities. This adjustment translates to a reduction of $2.5 million, in which $1.2 million will be adjusted from MWC EY for gas metering expenses and $1.3 million will be reduced from MWC 74 for gas metering capital expenditures.

ORA's calculation yields a unit cost of $8.84, an increase of $0.42 and not $1 per gas meter as PG&E had forecasted. See Table 7-11 below for a breakdown of PG&E's and ORA's 2003 overall forecast and by FERC Accounts.

Table 7-11

MWC EY, GAS METERING
PG&E's AND ORA's 2003 FORECAST
FERC ACCOUNTS 876, 878, 880, 890, and 893
(In Thousand of Nominal Dollars)

		PG&E	ORA	PG&E>ORA
Gas Metering Expenses	Expenses	17,945	16,745	1,200
	Capital	19,601	18,301	1,300
	Unit Cost	$9.42/gas meter	$8.84/gas meter	$0.58/gas meter
FERC ALLOCATION				
	876	1,445	1354	91
	878	3,952	3702	250
	880	629	589	40
	890	3,854	3610	244
	893	5,494	5146	348
Total FERC Expenses		15,374	14,401[27]	973

O. MWC FG, Operate Gas Distribution System FERC Accounts 874 and 875

MWC FG expenses include costs to monitor the system pressures, flows, odorant levels, and operating valves and regulator stations. Basic activities of this MWC include adjusting gas flow rates and adjusting the

[27] This amount is 86% of the total gas metering expenses derived by dividing the total expenses for all gas FERC Accounts, $15,374 by the total forecast for gas metering expenses of $17,945 as shown in Table 10-7, p. 10-19, Exhibit PG&E-2, and excludes taxes and pensions and benefits.

overall regulator station output during high demand periods and changing pressure recording charts.[28]

PG&E's 2003 forecast in overall expenses for MWC FG is $2.9 million. Of this total, $1.2 million is allocated to FERC Account 874 and $956,000 is allocated to FERC Account 875, and $371,000 to FERC Account 880, totaling $2.5 million. PG&E's 2002 actual expenses for FERC Accounts 874, 875 and 880 are $2.7 million, which is slightly higher than $2.5 million that PG&E had forecasted.

ORA finds PG&E's 2003 request to be reasonable and accepts PG&E's forecast.

P. MWC FH, Preventive Maintenance FERC Accounts 880, 887, 889 and 892

MWC FH tracks expenses to maintain regulator station, distribution valve, service valve replacement, Gas Pipeline Replacement Program (GPRP) expenses, and miscellaneous maintenance on mains and services. PG&E's 2003 request of $7.767 million in expenses for MWC FH are broken down into the following categories: (1) General, (2) Regulator Station Maintenance, (3) Miscellaneous Maintenance of Services, (4) Distribution Valve maintenance, (5) Service Valve Replacement, and (6) GPRP expenses.

ORA finds that the activities described in this MWC are important in maintaining a safe distribution system. However, ORA disagrees with the methodology PG&E used to arrive at 2003 expenses for two categories of MWC FH; (1) Regulator Station Maintenance, and (2) Distribution Valve Maintenance.

According to PG&E, Federal pipeline safety regulations require PG&E to annually inspect and maintain all district regulator stations in its

[28] PGE&E 2, p. 13-28:30.

system. PG&E complies with the regulations by conducting annual inspections, called "A" inspections, which consist of inspecting and cleaning the underground regulator station vault or pit, or the aboveground regulator station yard. PG&E then checks to ensure the station is operating as intended and to ensure that the station's over-or-under-pressure protection devices perform as expected. PG&E also conducts internal inspections, called "B" inspections, which consist of disassembling certain pressure regulating devices and inspecting the internal components for damage, and making any repairs indicated by the inspections. [29]

PG&E changed its standards from performing "B" inspections every 4 years to every 8 years in August of 2001.[30] PG&E's definition of a basic unit of work per regulator station is a "run." A run is a system of equipment for filtering the gas, regulating its pressure and protecting against over-pressurization. Some regulator stations have "dual runs" within the same station and PG&E counts the maintenance of these stations as 2 units of work, one unit per run. PG&E forecasts that in 2003, the company will be performing 4,271 runs on approximately 4,000 regulator stations at a unit cost of $716 per run. PG&E states that the unit cost per run is a blended unit cost for all divisions, and includes both type "A" and type "B" inspections.[31]

ORA asked PG&E to provide the unit cost of a type "A" vs. type "B" inspection, PG&E responded that it does not track the unit cost separately.[32] When ORA asked how many of the 4,271 runs that PG&E plan to inspect in 2003 are single vs. dual runs, PG&E stated that it only tracks the number of runs inspected, not whether the runs are associated with single or dual-run

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[29] PG&E-2, p. 13-33.

[30] PG&E data response to ORA DR 196, Q.1.

[31] PG&E data response to ORA DR 105, Q.3.

[32] PG&E data response to ORA DR 196, Q. 2A.

regulator stations. However, PG&E projected that in 2003, it will inspect 1,523 single runs and 1,374 dual runs based on the recorded 2001 ratio of dual run stations to total inspections.[33]

ORA finds PG&E's 2003 forecast of the total number of inspections is higher than historical average and PG&E's treatment of the unit cost for the second run of a dual-run regulator station, as a full unit of work, to be overstated. ORA used the 6 year average (1997-October 2002) of regulator station maintenance and arrived at a total of 3,933 runs with 1,419 single and 1,257 dual runs for the 2003 forecast. PG&E should not incur labor hours twice for travel time and certain activities such as clean up/maintenance of yard, setup/safety/parking, and pump vaults, for the second run of the 1,257 dual run regulator stations. ORA understands that when PG&E performs the inspection of the second run of a dual run regulator station, the company's employees are already at the station to perform the inspection on the first run. Since the inspection of the second run doesn't entail additional miscellaneous station activities, PG&E should not incur these costs again for additional work that does not involve any of the above in the second run or in performing a "B" inspection.

PG&E provided ORA a spreadsheet with calculations of labor hours for "A" and "B" maintenance of district regulator stations. ORA does not accept PG&E's forecast of $715.5 as the unit cost for the first run because PG&E did not revise its unit cost to include the change in its standards of performing "B" inspections from every 4 years to every 8 years. ORA's calculation, based on PG&E's labor spreadsheet, shows a more accurate unit cost of $575 per run for the first run, and includes the change in PG&E's "B" inspections schedule. Additionally, ORA used PG&E's labor hour

[33] PG&E data response to ORA DR 196, Q. 3C.

spreadsheet to arrive at a unit cost for the second run which excludes the labor hours for work already performed on the first run such as travel time and miscellaneous yard maintenance already included in the first run. ORA recommends a unit cost of $488 per run for any additional runs within the same station or at the same location.

Based on ORA's recalculations above, 2,676 runs should be charged at $575 per unit of work and 1,257 runs should be charged at $488 per unit of work. This yields a total of $2.152 million in expenses for regulator station maintenance. This total is $904,000 less than PG&E's 2003 forecast of $3 million for regulator station maintenance.

ORA recommends an adjustment of $305,000 for distribution valve maintenance. ORA recommends a different unit cost and an adjustment to the number of units of work forecast for distribution valve maintenance. PG&E forecasts a unit cost of $108.58 per distribution valve maintained for 8,563 valves in 2003. This unit cost is $13.40 higher than the 2000 recorded unit cost, but PG&E plans to maintain 1,350 less valves in 2003. PG&E attributes the increase in unit cost to "…increased in travel time per valve associated with fewer valves per zone and recording corrective maintenance costs properly to MWC FI, Valve Repair."[34] For example, PG&E explains that, if there were 10 valves to maintain in a set geographical area previously but now there are only 7 valves to maintain, the maintenance employee must still continue to travel the same number of miles from their headquarters to the various points to maintain the 7 valves.[35]

ORA disagrees with PG&E's argument. The unit cost of valve maintenance for 2003 should be the same as the 2000 unit cost of $95.18 per

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[34] PG&E-2, p. 13-37.

[35] PG&E data response to ORA DR 232, Q. 4b.

valve. This unit cost included travel expenses for PG&E's maintenance personnel to travel the entire territory where the 9,913 valves were located in 2000. This unit cost should be adopted for 2003 because according to PG&E, the company's personnel will continue to travel the same number of miles for valve maintenance but they will maintain 1,350 less valves than in 2000.

Additionally, ORA finds that the number of valves maintained by PG&E has been decreasing at an average of 9.6% for the past 5 years.[36] ORA recommends a reduction of 9.6% to the recorded 2002 number of valves maintained for the 2003 forecast. PG&E maintained 7,266 valves in 2002. ORA's 2003 forecast for the number of valves maintained in 2003 is 6,568, which is 698 less than the number of valves maintained in 2002.[37] ORA's total adjustment for valve maintenance is $305,000.

ORA's 2003 total forecast for MWC FH is $6.6 million. This amount includes ORA's adjustments in the unit cost of regulator station maintenance and distribution valve maintenance. Table 7-12 below shows a breakdown of PG&E's and ORA's forecast and ORA's adjustment by FERC Accounts.

Table 7-12
MWC FH, PREVENTATIVE MAINTENANCE
PG&E's AND ORA'S 2003 FORECAST
FERC ACCOUNTS 880, 887, 889, and 892
(In Thousand of Nominal Dollars)

	PG&E's 2003 Forecast			ORA's Forecast			PG&E>ORA
	# Of Units	Unit Cost	Total	# Of Units	Unit Cost	Total	
Reg. Stations Maint.	4,271	$715.5	$3,056	3,933	$547	$2.152	904
Dist. Valve Maint.	8,563	$108.6	$930	6,568	$95.18	$625	305

[36] PG&E originally provided this information regarding valve maintenance as confidential information. However, they agreed to waive protection upon request by ORA.

[37] PG&E data response to ORA DR 232, Q. 4a.

All Other Expenses		3,781	3,781	0
Total Expenses for MWC FH		7,767	6,558	1,209
FERC ALLOCATIONS FOR 880,887,889, and 892				
FERC	% Of FH	Amount	2003 FERC Forecast	PG&E>ORA
880	10%	813	686	127
887	19%	1480	1249	231
889	33%	2586	2183	403
892	23%	1785	1507	278
Total FERC	86%	6664	5626	1,038

Q. <u>MWC FI, Corrective Maintenance</u>
<u>FERC Accounts 887,889,892,894</u>

MWC FI tracks expenses for work done in repairing and replacing damaged or failed facilities. Corrective maintenance is broken down into the following categories: (1) Leak Repair, (2) Cathodic Protection Restoration, (3) Regulator Station Repair, and (4) Distribution Valve Repair.

PG&E is requesting $20.8 million in overall expenses for MWC FI in 2003. Of this total, $17.9 million is allocated to FERC Accounts 887, 889, 892, and 894.

PG&E's 2003 forecast of expenses to repair 867 regulator stations at a unit cost of $1088.72 is excessive. The 2003 unit cost per repair is 49% higher than the 2000 unit cost. PG&E's proposed increase is based on program manager's discussions with supervisors and technicians who determined that repairs previously performed were resulting in more comprehensive and expensive repairs in the future.[38] PG&E informed ORA that there were no studies or surveys performed which led PG&E to this conclusion.

ORA recommends an adjustment of $614,000 to PG&E's 2003 forecast due to ORA's adjustments to the forecast of the unit cost and the

[38] PG&E data response to ORA DR 232, Q. 7C

number of regulator stations repaired. PG&E states that the unit cost for regulator station repairs is 70% of the 2001 FH-Regulator Station Maintenance calculated Class "B" inspection unit cost because a typical regulator station repair is similar to that required for a class "B" internal inspection.[39] ORA recommends a unit cost of $761 per repair, instead of PG&E's forecast of $1088, based on revised labor hour calculations. ORA's calculation incorporates PG&E's new standards of performing "B" inspections every 8 years rather than every 4 years. ORA also recommends an adjustment to the forecast of units repaired from 867 to 434. PG&E's new standard of performing half of the number of internal inspections compared to previous years means that PG&E will have half the number of regulator station repairs to perform in 2003. Table 7-13 below provides a summary of PG&E's and ORA's 2003 forecasts for MWC FI.

Table 7-13
MWC FI, CORRECTIVE MAINTENANCE
(In Thousands of Nominal Dollars)

	PG&E's 2003 Forecast			ORA's 2003 Forecast		
	Unit	Unit Cost	Total	Units	Unit Cost	Total
Reg. Stations Repaired	867	$1,088.72 Per Reg. Station	944	434	$761.43 Per Reg. Station	330
BY FERC ACCOUNT						
	% Of Total FERC		PG&E	ORA	PG&E>ORA	
887	49%		8,795	8535	260	
889	5%		927	900	27	
892	42%		7,491	7270	221	
894	4%		693	673	20	
TOTAL FERC			17,906	17,387	528	
Total MWC FI			20,803	20,189	614	

[39] PG&E data response to ORA DR 232, Q. 7 C.IV

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R. MWC FM, Manage Information Technology FERC Accounts 880 and 879

MWC FM tracks expenses for the management of information technology. Maintenance of the software programs includes resolving integration issues between programs, training users, answering user question, resolving errors, backing up data, recommending timely upgrades, tracking system performance, and negotiating licenses and contracts. For 2003, PG&E forecasts $13.8 million in expenses for MWC FM. Of this total, PG&E has allocated $3.3 million to Gas Distribution O&M expenses and $9.3 million to Electric Distribution O&M expenses.

ORA recommends that the 2003 forecast expenses for MWC FM be adjusted from $13.8 million to $9.4 million. ORA's adjustment is based on allowing PG&E to recover the costs associated with its Mapping Improvement Program (MIP Phase II) over a longer time frame than requested.[40] See Chapter 6, Electric Distribution O&M Expenses, for a detailed analysis of ORA's analysis and recommended adjustment of this MWC.

ORA's adjustment translates to a reduction of $1 million (in nominal dollars) in expenses for Gas Distribution O&M FERC Account 880 of MWC FM. ORA's forecast for FERC Account 880 is $2.3 million in contrast to PG&E's forecast of $3.3 million in expenses for Gas Distribution O&M expenses for MWC FM in 2003.

S. MWC GF, Gas Mapping FERC Account 880

MWC GF tracks expenses associated with PG&E's permanent gas facility records. These records detail the size, material type, location,

[40] PG&E-2, p.12-15.

configuration, and other essential information needed to identify the thousands of miles of underground distribution main and millions of services. Specific activities include posting information for construction orders that have been closed in the accounting system, making map and data corrections, and providing information to avoid conflicts with government agency-proposed utility and infrastructure projects.[41]

PG&E's 2003 forecast of $3 million in overall expenses reflect normal, routine operation and are not expected to change from 2000 recorded amount. PG&E's 2002 actual expenses were $2.2 million and the company's forecast was $2.9 million. The recorded expenses for MWC GF in 2000 and 2001 were $2.9 million and $2.8 million, respectively.

ORA finds PG&E's 2003 request higher than historical expenses for this MWC, especially since PG&E states that its 2003 request "normal" and "routine" operation. ORA recommends an adjustment of $400,000 to MWC GF, by using an average of historical expenses for 2000-2002 to develop its 2003 forecast. This adjustment reduces the expenses of FERC Account 880 by $283,000.

T. MWC GG, Gas Engineering and Planning FERC Account 880

MWC GG tracks expenses for activities such as preliminary engineering or feasibility studies that gas planning engineers perform before a capital order is established. Additionally, planning engineers also perform relief valve calculations, provide recommendations for system operations and re-construction, and perform winter operating and curtailment planning. The total recorded expenses for this MWC in 2000 and 2001 were $1.953 million and $1.824 million, respectively.

[41] PG&E-2, p. 13-72.

PG&E's 2003 forecast of $2.437 million in expenses reflect an increase of approximately $600,000 over 2001 recorded amount due to wage increases and PG&E's expectation to fill 3 positions that were vacant in 2002 and 2003. PG&E's 2002 forecast was $2.366 million and its actual expenses were $2.240 million.

PG&E's 2003 forecast for MWC GG is reasonable and ORA accepts PG&E's forecast for Gas Distribution expenses in this MWC.

U. MWC GM, CEE Non-Balancing Account (Combustion Appliance Safety Testing) FERC Account 879

MWC GM tracks expenses for the performance of Combustion Appliance Safety (CAS) testing in conjunction with the Low-Income Energy Partners Program, the Residential Contractor Program, and the Summer Initiative Program.[42]

In 2000, PG&E performed 38,000 CAS tests in conjunction with its energy efficiency programs. The unit cost to perform the tests and including energy efficiency spending was $44.65 per unit of work. PG&E's workpapers show that, in 2001, due to productivity improvements PG&E's unit cost decreased to $32.92 per test.[43]

In December of 2001, the Commission ruled that PG&E must calculate the cost of the CAS test as if it was a stand alone test, instead of assigning the actual time the inspector spends on the CAS test and on evaluating potential energy efficiency measures.[44]

PG&E is requesting $4.7 million in expenses for MWC GM in 2003, which is more than $3 million more than the 2001 recorded expenses.

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[42] PG&E-2, p. 13-47.
[43] PG&E-2, Workpapers, p. 13-57.
[44] D.01-12-020, mimeo p. 52; and mimeo p. 70, finding of Fact No. 27.

PG&E believes that it costs more to perform the CAS test now that it is calculated separately from the energy efficiency programs. PG&E's 2003 unit cost is $46.30 and the company expects to perform 100,570 CAS tests.

ORA disagrees with PG&E's methodology of calculating the 2003 forecast. PG&E's workpaper shows that the 2001 unit cost to perform the CAS test in conjunction with the energy efficiency evaluation was $32.92.[45] PG&E's workpaper further show that the labor allocation for the CAS test alone was 73% of the combined unit cost. PG&E's justification for the unit cost increase of $14.50 for the 2002 forecast is inadequate and the request is excessive. It is unreasonable to expect that by performing 27% less work, it actually costs 44% more.

ORA recommends using the 2001 recorded unit cost of $32.92 as a basis for the 2003 unit cost. Since the CAS test is 73% of the cost, the CAS test alone expense should be $24 per test. Applying this unit cost to the 100,570 tests that PG&E plans to perform in 2003 yields the total amount of $2.4 million. ORA's 2003 forecast for MWC GM is $2.4 million. Table 7-14 below shows the translation of ORA's adjustments to FERC Account 879 of MWC GM.

Table 7-14
MWC GM, COMBUSTION APPLIANCE SAFETY TESTING
(In Thousands of Nominal Dollars)

RECORDED EXPENSES FOR MWC GM			PG&E'S 2003Forecast	**ORA's Forecast**
2000	2001	2002	2003	**2003**
1,716	1,663	3,763	4,655	**2,416**
FERC Accts.	PG-E's 2003 Forecast	FERC Amounts As % of Total GM	ORA's Adjustments to 2003 Forecast	
879	4,445	95%	(2,138)	
Total FERC	4,445		(2,138)	
Total GM	4,655		(2,239)	

[45] Ibid.

V. GAS PROCUREMENT ADMINISTRATION
MWC CV, Other Purchased Gas Expenses
FERC Account 807.5

MWC CV tracks the Gas Procurement Department's expenses to purchase natural gas supplies and transportation capacity to meet PG&E's bundled core gas customer demands. Gas procurement is the process of acquiring gas supplies and managing transmission and storage capacities for gas utilities customers. According to PG&E, these acquisition activities include the physical receipt and monitoring of gas supplies transported by upstream pipeline companies, which have been procured on behalf of customers. Management activities include brokering or assigning unused transportation capacity, scheduling and pipeline balancing of core supplies, occasional sales of excess supplies, and storage optimization.[46]

PG&E's 2003 forecast of overall expenses for MWC CV is $4.1 million. This total amount is directly allocated to FERC Account 807.5. This amount represents an incremental increase of $146,000 above the 2001 recorded amount. This increase is for ongoing programming and operating costs for GMS, a software application PG&E purchased in 1998 to track natural gas supply purchases, schedule purchases for transportation on natural pipelines, account and pay for purchases and transportation costs, and report Gas Portfolio Risk. Aside from this incremental increase, the Gas Procurement Department has been able to maintain flat costs and staffing levels, which consists of 27 employees, since 1999.

ORA finds PG&E's 2003 request to be reasonable and accepts its forecast for MWC CV.

[46] PG&E-4, p. 14-3:4.

IV. DISCUSSION/ANALYSIS—SUMMARY OF ORA'S ADJUSTMENTS BY FERC ACCOUNTS AND IN BASE YEAR DOLLARS.

In this section, ORA presents only the MWCs with ORA's adjustments and the translation of ORA's adjustments from each of the MWC discussed in Section III above, into the respective FERC Accounts, and into 2000 constant dollars. See Table 7-15 below. ORA accepts PG&E's factors for labor and non-labor escalations used in its 2003 forecast as presented in this Application. (See Chapter 5, Cost Escalation, for more details.)

Table 7-15
SUMMARY OF ORA's ADJUSTMENTS TO
PG&E'S 2003 FORECAST
(In Thousand of Dollars)

		PG&E's 2003 Forecast		ORA's 2003 Forecast		PG&E> ORA	PG&E> ORA
MWC	**FERC**	**In Nominal Dollars**	**In 2000 Dollars**	**In Nominal Dollars**	**In 2000 Dollars**	In Nominal Dollars	**In 2000 Dollars**
DD	879	40,933	37,606	38,933	35,781	2,000	**1,825**
DF	874	9,336	8,636	8,926	8,258	410	**378**
DG	880	363	342	302	284	61	**58**
	887	5,739	5,294	4,769	4,400	970	**894**
EX	893	2,106	1,945	1,769	1,634	337	**311**
EY	876	1,445	1,343	1,354	1,258	91	**85**
	878	3,952	3,672	3,702	3,443	250	**230**
	880	629	585	589	548	40	**37**
	890	3,854	3,582	3,610	3,355	244	**227**
	893	5,494	5,106	5,146	4,783	348	**323**
FH	880	814	772	686	651	127	121
	887	1,480	1,371	1249	1,158	231	213
	889	2,586	2,396	2183	2,022	403	373
	892	1,785	1,657	1507	1,399	278	258
FI	887	8,795	8,182	8535	7940	260	242
	889	927	863	900	837	27	26
	892	7,491	6,965	7270	6759	221	206
	894	693	646	673	627	20	19
FM	880	3,315	3,130	2,268	2,142	1,047	989
GF	880	2105	1931	1,822	1672	283	**259**
GM	879	4,445	4,243	2,307	2,198	2,138	**2,045**
TOTAL		**108,287**	**100,267**	**98,500**	**91,149**	**9,786**	**9,119**

Table 7-15 above shows that ORA's total adjustment to PG&E's 2003 Gas Distribution O&M expenses is $9.1 million in 2000 dollars. The MWCs and FERC Accounts that ORA has recommended adjustments to 2003 expenses are DD, DF, DG, EX, EY, FH, FI, FM, GF and GM and Accounts 874, 876, 878, 879, 880, 887, 889, 890, 892, 893 and 894.

V. CONCLUSIONS

ORA has reviewed PG&E's 2003 forecast for Gas Distribution O&M expenses and finds that many of PG&E's requests are reasonable. ORA agrees with PG&E's request for expenses in MWCs AK, AR, CG, CM, CR, DD, DE, DN, ES, EW, FG, GG, and CV. However, ORA finds that its approach in forecasting 2003 expenses is more reasonable and reflective of historical expenses for some of PG&E's MWCs. ORA recommends the Commission adopt its 2003 forecast of Gas Distribution O&M expenses because ORA's forecast is more comparable to PG&E's actual spending for the past 6 years. PG&E's overall Gas Distribution O&M expenses have been decreasing between 1997 and 2001 from $162.1 million to $104.9 million.[47] However, during this period the Commission authorized Gas Distribution O&M expenses were between 1% and 24% higher than the company's actual expenditures. ORA's analysis shows that an adjustment of $9.8 million in nominal dollars (and $9.1 million in 2000 dollars) in PG&E's Gas Distribution O&M forecast for 2003 is appropriate and reflective of PG&E's historical spending. ORA notes that $2 million, in nominal dollars (and $1.8 million, in 2000 dollars) of ORA's total adjustment is derived from ORA's recommendation of redistributing PG&E's Electric and Gas Distribution allocations for MWC DD in 2003 so that they would more closely resemble 2002 actual expenses and not due to ORA's disagreement with PG&E's forecast for this MWC. ORA's adjustments reflect ORA's analysis of work activities and adjustments in MWC DD (Provide Field Service), MWC DG (Cathodic Protection), MWC EX (Meter Protection), MWC EY (Install Meters and Devices), MWC FH (Preventative Maintenance), MWC FI (Corrective Maintenance), MWC FM (Manage Information Technology), MWC GF (Gas Mapping) and MWC GM (Combustion Appliance Safety Testing).

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[47] PG&E data response to ORA DR 195, Q. 4a.

Attachment 1

A COMPARISON OF PG&E'S ACTUAL AND
COMMISSION AUTHORIZED O&M GAS DISTRIBUTION EXPENSES
FOR THE PERIOD 1990-2001 BY FERC ACCOUNTS

FERC		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
871	Adopted	953	967	941	1018	1019	1038	1544	1499	1459	680	660	641
	Actual	1022	1635	1660	1924	1734	837	649	1682	809	256	270	252
	DIFF	7%	69%	76%	89%	70%	-19%	-58%	12%	-45%	-62%	-59%	-61%
874	Adopted	3179	3203	3141	4290	4311	4368	3716	3622	3546	14480	14048	13671
	Actual	4135	3968	3739	4089	3311	6103	6925	25879	18070	16443	14457	14235
	DIFF	30%	24%	19%	-5%	-23%	40%	86%	614%	410%	14%	3%	4%
875	Adopted	872	882	861	821	824	837	682	664	649	855	830	807
	Actual	824	685	658	789	656	804	917	923	879	809	761	1003
	DIFF	-6%	-22%	-24%	-4%	-20%	-4%	34%	39%	35%	-5%	-8%	24%
876	Adopted	1205	1216	1190	1021	1024	1040	907	882	861	512	497	483
	Actual	1025	795	1014	969	1057	231	478	358	360	374	24	3565
	DIFF	-15%	-35%	-15%	-5%	3%	-78%	-47%	-59%	-58%	-27%	-95%	638%
878	Adopted	30191	30494	29822	26564	26635	27074	19448	18906	18426	2582	2506	2437
	Actual	22695	20739	21884	21954	20341	26142	16008	2709	5570	3101	3458	1404
	DIFF	-25%	-32%	-27%	-17%	-24%	-3%	-18%	-86%	-70%	20%	38%	-42%
879	Adopted	22623	22811	22350	30987	31112	31558	21711	21162	20709	56428	54770	53223
	Actual	28573	30718	30125	27426	28999	49174	58612	65954	42991	38309	43639	39356
	DIFF	26%	35%	35%	-11%	-7%	56%	170%	212%	108%	-32%	-20%	-26%
880	Adopted	37282	37571	36834	34655	34833	35272	34557	33731	33084	21198	20549	20051
	Actual	34731	39521	43682	40032	42138	22806	11342	10876	12633	14613	13133	8227
	DIFF	-7%	5%	19%	16%	21%	-35%	-67%	-68%	-62%	-31%	-36%	-59%
881	Adopted	199	192	186	43	43	43	31	31	30	0	0	0
	Actual	43	36	35	32	45	-124	2			0	0	0
	DIFF	-78%	-81%	-81%	-26%	5%	-388%	-94%	-100%	-100%	0%	0%	0%
Operations Adopted		96504	97336	95325	99399	99801	101230	82596	80497	78764	96735	93860	91313
Operations Actual		93048	98098	102797	97214	98281	105973	94933	108380	81312	73905	75742	68043
885	Adopted	6291	6379	6212	6318	6325	6446	4203	4088	3989	0	0	0
	Actual	6340	6567	6487	6148	5298	5793	2501	0	0	0	0	0
	DIFF	1%	3%	4%	-3%	-16%	-10%	-40%	-100%	-100%	0%	0%	0%
886	Adopted	6	6	6	1	1	1	1	1	1	1253	1216	1183
	Actual	1	1		1	506	2780	1205	122	25	0	0	0
	DIFF	-85%	-91%	-93%	-30%	50482%	277911%	120359%	12103%	2401%	-100%	-100%	-100%
887	Adopted	21476	21572	21223	17553	17633	17871	13651	13310	13032	19168	18597	18098
	Actual	16143	16720	15276	16529	14396	18750	20408	22687	19929	19940	15913	15143
	DIFF	-25%	-22%	-28%	-6%	-18%	5%	49%	70%	53%	4%	-14%	-16%
889	Adopted	2468	2487	2438	2662	2674	2710	1348	1314	1286	2040	1979	1926
	Actual	2672	2459	2540	1472	1040	1028	3282	4624	3539	2764	2914	2889
	DIFF	8%	-1%	4%	-45%	-61%	-62%	143%	252%	175%	36%	47%	50%
890	Adopted	1411	1424	1393	1100	1104	1120	955	930	909	1489	1445	1406
	Actual	1103	1234	1025	1047	896	1289	1941	2020	2853	2547	3053	3054
	DIFF	-22%	-13%	-26%	-5%	-19%	15%	103%	117%	214%	71%	111%	117%
892	Adopted	13417	13497	13257	12210	12263	12433	11352	11066	10832	12403	12034	11711
	Actual	10729	11795	11596	12652	10757	10023	12498	13218	11005	9536	9613	9621
	DIFF	-20%	-13%	-13%	4%	-12%	-19%	10%	19%	2%	-23%	-20%	-18%
893	Adopted	6829	6878	6747	5454	5476	5555	4350	4235	4137	6511	6317	6147
	Actual	4846	4482	4504	4988	5017	3291	8748	8749	5159	7054	6237	3936
	DIFF	-29%	-35%	-33%	-9%	-8%	-41%	101%	107%	25%	8%	-1%	-36%
894	Adopted	52403	52752	51776	45857	46036	46704	38650	37670	36863	48600	47151	45886
	Actual	855	1292	1383	2899	2820	11541	4814	2338	1066	1567	1925	2234
	DIFF	-98%	-98%	-97%	-94%	-94%	-75%	-88%	-94%	-97%	-97%	-96%	-95%
Maint. Adopted		104301	104995	103052	91155	91512	92840	74510	72614	71049	91464	88739	86357
Maint. Actual		42688	44549	42811	45735	40730	54495	55396	53757	43577	43409	39654	36877
Total O&M Adopted	**1990-2001**	**163778**	**165154**	**161789**	**158899**	**159524**	**161836**	**132675**	**129300**	**126510**	**145334**	**141010**	**137200**
Total O&M Actual	**1990-2001**	**148823**	**158478**	**159706**	**156388**	**150491**	**173930**	**155767**	**162138**	**124889**	**117314**	**115396**	**104920**
DIFFERENCE		**-9%**	**-4%**	**-1%**	**-2%**	**-6%**	**7%**	**17%**	**25%**	**-1%**	**-19%**	**-18%**	**-24%**

CHAPTER 8

CUSTOMER ACCOUNTS EXPENSE

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) sets forth its request for Customer Accounts Expenses in Chapter 4 of Exhibit PG&E-6. This chapter presents ORA's analysis of the company's proposal and ORA's recommendations for adjustments to Customer Accounts expense levels. This chapter also presents ORA's analysis of Customer Services O&M expenses as discussed in Chapter 5 of Exhibit PG&E-6.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations. Section III provides ORA's analysis of Customer Accounts Expense. Section IV presents ORA's analysis of Customer Services O&M expenses as discussed in Chapter 5 of Exhibit PG&E-6. Section V provides ORA's recommendations on PG&E's request for an increase in Non Sufficient Funds (NSF) Fee. Section VI presents the Excessive Overtime expense adjustments made in the Results of Examination Report to FERC Accounts 902 and 903, and Section VII presents ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

PG&E's total Customer Accounts Expense request of $366 million[1] exceeds ORA's recommendation by $19.287 million.

PG&E requests $27.758 million, recorded in FERC Account 903, for its Account Services activities in Major Work Category (MWC) EZ.[2] ORA

[1] PG&E-6, p.4-11

[2] PG&E-3, p. 3-26. . Amount is expressed in FERC view, in thousands of 2000 dollars.

recommends an adjustment of $6.217 million, resulting in a forecast of $21.541million for FERC Account 903 in MWC EZ.

PG&E requests $17.110 million in MWC DB (Receive and Assure Revenue) in Chapter 7, Exhibit PG&E-3 (Customer Revenue Transactions). ORA recommends a forecast of $16.995 million resulting in an adjustment of $0.115 million to PG&E's forecast. [3]

PG&E is asking for $49.402 million for MWC BJ (Operate Computer and Network Systems),[4] discussed in Chapter 3, Exhibit PG&E-5, CIS Replacement Project Expense. ORA recommends a forecast of $43.547 million in FERC Account 903 in MWC BJ, an adjustment of $5.855 million.

PG&E's total Customer Services O&M expense request of $7.304 million[5] exceeds ORA's recommendation by $1.884 million.

As part of Customer Services O&M expenses PG&E's request for Customer Retention and Economic Development Expenses is $2.460 million,[6] in MWC FK. ORA recommends eliminating the Customer Retention Expenses portion of this MWC. This results in a forecast of $0.588million for FERC Account 912[7] for Economic Development expenses also included within MWC FK.

PG&E is requesting an increase in the Non-Sufficient Funds Fee from $6 to $10. ORA recommends limiting the increase to $8.

ORA has incorporated adjustments of $1.7 million to Account 902 and $5.4 million to Account 903 associated with excessive overtime costs which is supported in the "Results of Examination Report."

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[3] Amounts are expressed in FERC view, in 2000 dollars and are charged to Account 903.

[4] PG&E-5, p. 3-27

[5] PG&E-6, p.5-2

[6] PG&E-3, p. 8-21. Amount is expressed in FERC view, in 2000 dollars.

[7] Refer to ORA's workpaper for MWC FK

III. ANALYSIS OF CUSTOMER ACCOUNTS EXPENSES

Exhibit PG&E-6, Chapter 4 introduces PG&E's Customer Accounts Expenses.

In Exhibit PG&E-3, Chapters 2 (Customer Inquiry Assistance), 3 (Account Services), 4 (Field Service and Dispatch), 5 (Read and Investigate Meters, 6 (Local Office Transactions) and 7 (Customer Revenue Transactions) discuss part of the Customer Accounts Expenses in detail. Other Customer Accounts expenses are also discussed in Exhibit PG&E-4 and Exhibit PG&E-5. These expenses are included in FERC Accounts 902 and 903. This section discusses all the exhibits by MWC category below.

A. <u>MWC DK-Customer Inquiry Assistance</u>

Exhibit PG&E-3, Chapter 2 discusses PG&E's Customer Inquiry Assistance activities. MWC DK includes expenses associated with PG&E's three Call Centers, the Consumer Affairs Unit, and the Correspondence Management and Research groups.[8] The 2003 forecast for these activities is $64.857 million.[9] The major cost components of this expense include the increased cost of labor and PG&E's need for hiring additional Customer Service Representatives (CSRs) for the new billing and information system.[10]

ORA performed an analysis of all expenses in this section and found them reasonable. ORA recognizes the importance of the call center functions and general support for handling consumer issues and investigating the nature of complaints and resolving them on time. ORA

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[8] PG&E-3, p. 2-12

[9] PG&E-3, p.2-19. Amount is in SAP view in 2000 dollars

[10] PG&E-3, p.2-12

performed an analysis of all expenses in this section and does not propose any adjustment beyond those recommended in ORA's "Results of Examination Report."

B. MWC EZ and GM, Account Services

In Exhibit PG&E-3, Chapter 3, PG&E describes Account Service activities that include basic customer services to its Commercial, Industrial and Agricultural (CIA) customers. These expenses are included in MWCs EZ (Customer Care) and GM (Customer Energy Efficiency Non-Balancing Account Programs). Although ORA does not recommend adjustments to MWC GM, ORA does recommend an adjustment to MWC EZ.

PG&E's Account 903 expense forecast for MWC EZ is $27.758 million for 2003.[11] According to PG&E, the account services functions, which are a subset of the many functions within this MWC, include activities that are basic customer services enabling PG&E to meet the needs of CIA business customers. The expense requested for these account services functions which exclusively apply to CIA customers is $17.894 million.[12]

PG&E's Accounts Services functions are similar to Southern California Edison's (SCE) Accounts Management Activities. However, PG&E's cost per CIA customer is $22.08 whereas Edison's cost is $14.41.[13] Because PG&E and SCE are similar in many ways--both are large utilities

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[11] PG&E-3, P.3-26

[12] Amount is in FERC view in 2000 dollars. See ORA Workpaper for MWC EZ

[13] PG&E requests $17,894 million in FERC 2000 dollars for 810,400 (PG&E-3, p. 3-6) CIA accounts resulting in a per CIA account expense of $22.08. SCE requested $8.65 million for 600,000 accounts in their 2003 General Rate Case application 02-05-004 resulting in a per customer expense of $14.41.

serving customers in California and both have a large number of CIA accounts--their Account Services costs can be compared.

ORA recommends an adjustment of $6.217 million based on a cost of $14.41 per CIA customer. PG&E has not demonstrated the reasonableness of its $22.08 per CIA customer cost estimate, which is 60% more than what it costs SCE to serve its CIA customers. Hence, ORA recommends a 2003 forecast of $21.541 million for PG&E's expenses in Account 903 in MWC EZ.

Funding for Account Services has been an issue in prior GRCs. A major portion of PG&E's Account Services funding requests have been disallowed in the past two PG&E GRCs. The adopted amounts for Account Service expenses in the 1996 and 1999 GRCs were $2.9 million and $17.63 million (in 2000 dollars), respectively.[14]

PG&E again asks for funding for the same basic customer service activities for its CIA customers for 2003. The Account Service activities remain essentially the same as the 1999 Account Service activities. Although ORA does not object to the account service activities PG&E proposes, it does recommend bringing PG&E's funding level on a per CIA customer basis in line with that of SCE. Adjusting the per CIA customer cost downward from $22.08 per customer to $14.41, results in a forecast of $21.541 million for Account 903 for MWC EZ. This forecast is still higher than what was adopted by the Commission in both the 1996 and 1999 GRCs, but less than the $27.758 million for Account 903 in MWC EZ requested by PG&E.

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[14]D.95-12-055, p. 42, disallowed PG&E's proposed spending of $20 million for its "Quality Contact" program. D.00-02-046, p. 21, again disallowed $20 million that it concluded had not been sufficiently justified.

Table 8-1

ACCOUNT SERVICES EXPENSES
FERC Account 903 - MWC EZ
(Dollars in thousands of 2000 dollars)

	ORA	PG&E	PG&E>ORA	Percent
Account Services Function	$11,677	$17,894	$6,217	34.74%
Customer Support Services	$9,864	$9,864	$0	0%
Total	$21,541	$27,758	$6,217	28.86%

C. MWC DC-Dispatch

MWC DC includes expenses for PG&E's Field Service and Dispatch activities that include fieldwork for completing customer service requests. [15] PG&E requests $15.892 million for MWC DC.[16]

ORA reviewed expenses in this MWC and does not recommend adjustments beyond those proposed to MWC DC in ORA's "Results of Examination Report" as mentioned in Section V on excessive overtime costs, below.

D. MWC AR-Read and Investigate Meters

Exhibit PG&E-3, Chapter 5 discusses PG&E's Meter Reading activities. PG&E's forecast for 2003 meter reading activities in FERC Account 902 is $83.765 million.[17] PG&E arrived at this forecast by adding

[15] PG&E-3, p.4-1

[16] PG&E-3, p.4-15. Amount in SAP 2000 dollars

[17] PG&E-3, p.5-19. Amount in SAP 2000 dollars and excludes $0.056 million of FERC 875 expense

planned expenses for 2003, deducting planned 2003 cost savings, and one-time, non-recurring costs from the recorded 2000 spending.[18]

ORA recognizes that accurate and timely meter reading is critical for generating accurate bills. Reducing the number of estimated bills is also a priority to reduce the number of billing adjustments and errors.

ORA does not recommend adjustments to MWC AR beyond those adjustments to Account 902 proposed in ORA's "Results of Examination Report" as mentioned in Section V on excessive overtime costs, below.

E. MWC FT –Customer Service Office Transactions

PG&E's Local Office Operation activities are discussed in Exhibit PG&E-3, Chapter 6. Local Office transactions include receiving bill payments and all customer service activities that are provided by the call centers. MWC FT includes expense related to all 83 Local Office and 400 Pay Station transactions.[19] PG&E requests $39.564 million,[20] the largest element of which is attributed to the increased cost of labor.[21]

Local Offices and Pay Stations provide customers the option to interact face to face with customer service representatives.

ORA does not recommend adjustments to MWC FT beyond those proposed to MWC FT in ORA's "Results of Examination Report" as mentioned in Section V on excessive overtime costs, below.

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[18] PG&E-3, p.5-3

[19] PG&E-3, p.6-5

[20] PG&E-3, p.6-8. Amount is in SAP 2000 dollars

[21] PG&E-3, p. 6-5

F. MWC FT, MWC DA and MWC DB, Customer Revenue Transactions

MWCs FT (Customer Service Office Transactions), DA (Process Customer Bills) and DB (Receive and Assure Revenue) include expenses described in Exhibit PG&E-3, Chapter-7 (Customer Revenue Transactions) of PG&E's testimony. ORA does not have issues with either FT or DA but has made an adjustment to MWC DB.

Exhibit PG&E–3, Chapter 7, PG&E describes its Customer Revenue Transaction activities as "the accurate and timely calculation and issuance of customers' gas and electric bills and the prompt collection of revenue."[22]

PG&E mentions that it would expect certain postage and material savings based on the combining of the credit deposit requests with the customers commencing bill statements.[23] PG&E did not mention how much these savings would be or where they would be reflected. Through data requests to PG&E, ORA has ascertained that PG&E would expect to see a savings of $175,205 per year.[24] PG&E did not include the savings in its 2003 forecast, as "it was unclear at the time of preparing testimony and workpapers when the savings would begin to accrue."[25] PG&E then went on to state, "2003 cost forecast for MWC DB should be reduced by $175,205."[26]

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[22] PG&E-3, p.7-1

[23] PG&E-3, p.7-15

[24] DR ORA_0106-02

[25] DR ORA_0256-04

[26] DR ORA_0256-04

Hence, ORA recommends adjusting PG&E's forecast of MWC DB by $0.175 million,[27] which equals an adjustment of $0.115 million in 2000 dollars to FERC Account 903.

G. Other MWCs

ORA did not have any adjustments to MWCs AB and FM beyond those proposed in ORA's "Results of Examination Report" as mentioned in Section V on excessive overtime costs, below.

Exhibit PG&E-5, Chapter 3, discusses expenses associated with MWC BJ, CIS Expenses. ORA proposes an adjustment of $5.855 million[28] out of PG&E's total request of $49.402 million. These expenses and ORA's recommended adjustment is discussed in detail in Chapter 12 of this report.

IV. ANALYSIS OF CUSTOMER SERVICES O&M EXPENSES

Exhibit PG&E-6, Chapter 5 (Other Operations and Maintenance Expenses) introduces PG&E's other distribution-related Operations and Maintenance (O&M) expenses that are not included in Chapters 2, 3, and 4 of Exhibit PG&E-6. According to PG&E, "Specifically, this chapter presents specific electric and gas customer services expenses and electric and gas production O&M expenses (referred to as Other O&M expenses in this chapter)."[29]

Exhibit PG&E-3, Chapter 8 (Customer Retention and Economic Development) and Chapter 10 (Low Emmission Vehicles) discuss these Customer Services O&M expenses in detail. These expenses are included in FERC Account 912. These expenses are dicussed in detail by MWC below.

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[27] Amount is in SAP nominal dollars

[28] Amount in FERC view in 2000 dollars. See Chapter 12 of this report for further discussion

[29] PG&E-6, p.5-1

A. MWC FK, Customer Retention and Economic Development

In PG&E-3, Chapter 8, Customer Retention and Economic Development (MWC FK), PG&E requests $2.460 million for FERC Account 912 for 2003.[30] Out of this total, $1.872 million is for Customer Retention and $0.588 million for Economic Development activities.[31]

According to PG&E, the Customer Retention expenditure supports the "effort to retain customers that would otherwise uneconomically bypass PG&E's distribution system by connecting to the electric transmission and/or distribution facilities of alternative distribution providers."[32] PG&E asserts that it has been facing increased levels of competition from irrigation districts, "over the fence" transactions and municipalization efforts from a number of cities and public agencies.[33]

PG&E claims it faces threats from irrigation districts but has failed to clearly demonstrate the extent of this threat or the harm to its ratepayers. PG&E does not provide specific examples of who its potential competition could be in the future or the technology and load capacities. Although PG&E describes past events, it has not provided evidence that there is a future threat from irrigation districts.

In the case of municipalization, according to Commission Decision 89-07-016, "ratepayers who remain with the private utility, will be in the same position before and after the transfer." The Commission indicated in the decision that it would exercise its authority to protect the interests of the

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[30] PG&E-3, p. 8-21. Amount is expressed FERC view, in 2000 dollars

[31] PG&E DR ORA_0246-01. Amounts have been converted to 2000 dollars and FERC view. See ORA workapapers for MWC FK.

[32] PG&E-3, p. 8-1

[33] PG&E-3, p.8-2

ratepayers who remain on the privately-owned utility system. Since the municipalization process would not harm ratepayers, they should remain indifferent to this effort and therefore should not have to finance retention expenses.

PG&E has the option of providing contracted rate discounts to its customers and also has a proposal for a new flexible pricing option, Schedule E-13, that is pending at the Commission.[34] Contract rate discounts, approved by the Commission in Decision 97-09-027, enable PG&E to offer flexible pricing schedules (below tariff levels) to retain a potential bypass customer who could connect to an alternative provider or install engine-driven pumping equipment.[35]

ORA recommends elimination of the Customer Retention expenses in FERC Account 912 for 2003, as it is not clear from PG&E's application that a threat of competition currently exists from irrigation districts. Hence, ORA recommends a forecast of $0.588 million in Account 903 for MWC FK, equal to PG&E's forecast for Economic Development activities. In the event of municipalization, the welfare of ratepayers would be ensured by the Commission pursuant to policies established in D. 89-07-016. For its customers who may be considering alternative offers from PG&E's competitors, PG&E already has contracted rates available.

Table 8-2

CUSTOMER RETENTION AND ECONOMIC DEVELOPMENT
FERC Account 912
(In thousands of 2000 dollars)

	ORA	PG&E	PG&E>ORA	Percent

[34]PG&E Advice 2278-E

[35] PG&E-3, p.8-4

Customer Retention Exp.	$0	$1,872	$1,872	100%
Economic Development Exp	$588	$588	$0	0%
Total	$588	$2,460	$1,872	76.10%

B. MWC CG-Low Emission Vehicles

MWC CG includes expenses for PG&E's Low Emission Vehicle (LEV) program in FERC Account 912. PG&E requests $2.95 million for its mandatory LEV activities.[36]

ORA has reviewed expenses in this MWC and does not recommend any adjustments.

V. NON-SUFFICIENT FUNDS FEE

PG&E seeks to increase its current Non-Sufficient Funds (NSF) Fee from $6.00 to $10.00. PG&E incurs these NSF costs when a customer's bank returns a check to PG&E due to insufficient funds in the customer's account. PG&E requests a $4.00 NSF fee increase to "reflect the actual processing costs of these returned checks."[37]

ORA recommends an increase in NSF fee from $6.00 to $8.00 instead of the requested $10.00 for the following reasons. An increase from $6 to $10.00 is a 66% above the current $6 fee. An increase of $2.00 recognizes PG&E's higher cost while also mitigating the impact on customers who pay the NSF fee.

Although PG&E does not track customers who bounce checks,[38] it can be presumed that a percentage of them are low-income customers. Hence, to mitigate the impact of a substantial increase in NSF fee on all customers and in particular

[36] PG&E-3, p.10-2

[37] PG&E-3, p. 9-2

[38] PG&E DR ORA_0245-03

the low-income customers, ORA recommends an increase of $2 (from $6.00 to $8.00), instead of the requested $4.00.

Limiting the increase to $8 also more closely tracks inflation than PG&E's proposal of $10. Escalating the $6 fee at 3% inflation from 1996 to 2003 would yield a fee of $7.38.[39] To the extent that the goal is to provide customers with an incentive not to bounce checks, an increase of $2 in the NSF fee should be sufficient without putting any undue burden on low-income customers.

VI. EXCESSIVE OVERTIME Adjustments TO FERC Accounts 902 and 903

The ORA "Results of Examination Report" discusses excessive overtime cost adjustments to FERC Accounts 902 and 903.

This report recommends adjustments of $1.7 million in 2000 FERC dollars for Account 902 (MWC AR) and $6.6 million in Account 903.

The entire adjustment of $1.7 million has been applied to the test year forecast for FERC Account 902 and $5.4 million (of the $6.6 million) has been applied to the test year forecast for FERC Account 903. The adjustment was prorated among the MWCs (AB, DA, DB, DC, DK, EV, FM, FT and GM).[40] ORA did not apply this adjustment to MWCs EZ and BJ since the adjustments for MWCs EZ and BJ were made by ORA independent of historic information.

VII. CONCLUSION

ORA recommends an estimate of $347 million, in contrast to PG&E's estimate of $366 million, for Customer Accounts Expenses to reflect the adjustments proposed in this chapter.

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[39] See ORA's workpapers on NSF fee

[40] See ORA workpapers on overtime expenses

Table 8-3

CUSTOMER ACCOUNTS EXPENSE

SUMMARY BY FERC ACCOUNT

(Dollars in thousands of 2000 dollars)

	ORA	PG&E	PG&E>ORA	Percent
902	$67,955	$69,655	$1,700	2.44%
903	$278,786	$296,373	$17,587	5.94%
Total	$346,741	$366,028	$19,287	5.27%

ORA recommends an estimate of $4.301 million for Customer Services expenses in FERC Account 912 in contrast to the PG&E estimate of $7.304 million for the reasons described in this chapter.[41]

Table 8-4

CUSTOMER SERVICES EXPENSE

SUMMARY BY FERC ACCOUNT

(Dollars in thousands of 2000 dollars)

	ORA	**PG&E**	**PG&E>ORA**	**Percent**
912	$4,301	$7,304	$1,884	25.80%

[41] Amounts are in FERC view, in 2000 dollars.

CHAPTER 9 – A
CUSTOMER SERVICE

LOCAL OFFICES, PAY STATIONS AND PAYMENT OPTIONS

I. INTRODUCTION

This chapter contains ORA's analysis of PG&E's Local Office and Pay Station network and bill payment options and recommendations regarding needed improvements. Most of PG&E's customers, about 68%, pay their bills by mail and conduct other business with the company by telephone. The next largest group, about 18%, is customers who pay their bills and conduct other PG&E transactions in person. The main focus of this chapter is the latter group of customers and the facilities that serve them.

Section II of this chapter summarizes changes recommended in PG&E's Network Study and ORA's recommendations regarding Local Offices, Pay Stations and payment options. Section III describes the operations of PG&E's Local Offices, Pay Stations and Call Center and the payment options available to PG&E's customers. Section IV summarizes the findings and recommendations of the Network Study and discusses ORA's recommendations with respect to Local Offices, Pay Stations and payment options. Section V concludes this chapter.

II. SUMMARY/RECOMMENDATIONS

PG&E asserts in PG&E-3, Chapter 6, that its Local Offices are operated efficiently, and that its requested expenses are reasonable and justified. PG&E makes no recommendations in this proceeding for changes in either its Local Office or Pay Station operations. However, in 1999, PG&E contracted with

Verdi & Company to study PG&E's Local Office and Pay Station Network. That study [1] (the Network Study), completed and issued in April 2001, found several areas in need of improvement and recommended changes to PG&E's in-person customer service network. ORA notes the Network Study's findings and recommends generally that PG&E reassess those findings and pursue implementing the study's recommendations.

Also in 1999, PG&E contracted with Opinion Dynamics Corporation to conduct a survey of customer satisfaction regarding its Local Offices and Pay Stations. That survey (CS Survey) identified areas where customer service might be improved.[2] No subsequent surveys have been conducted to determine whether Local Office or Pay Station service and/or customer satisfaction have changed for better or worse since 1999.

ORA's Recommendations

1. PG&E should evaluate and follow up on recommendations in the Network Study. Specifically, ORA recommends that PG&E:
   - ❑ Measure activities other than payments at local offices to determine if appropriate to downsize, transform, add or close offices.[3]
   - ❑ Reopen closed Drop Boxes and process and post payments deposited before 2:00 p.m. on the day of deposit.[4]
   - ❑ Educate customers about available payment options and encourage them to use less costly, more convenient payment and service options, such as mail and on-line.[5]

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[1] The study is entitled, "Pacific Gas & Electric, Delivery Network Optimization and Primary Research Project," and is dated April 2001.

[2] "Front Counter/Paystation Survey," prepared by PG&E's Customer Opinion Research Department, February 1999.

[3] Network Study, Sec. 7, p. 39.

[4] *Id.*, Sec. 7, p. 40.

- ❑ Explore adding self-service, un-staffed, payment and information facilities; include assessing the feasibility of a "shared pay station network."[6] (This action could entail a scenario in which PG&E initiates the service and promotes it to other entities that would pay PG&E a fee for the service, thereby enhancing PG&E revenues.)
- ❑ Consider adding Local Offices. Re-assess the findings of the Network Study with the latest information available, evaluate ratepayer benefits and consider opening new Local Offices, if appropriate.
- ❑ Initiate process to determine if it is appropriate to close Local Offices flagged by the Network Study as candidates for closure, i.e., offices with low volume, high payment transaction percentages, and reasonably close alternative Pay Stations. Apply the office closure procedure specified in D. 98-07-077, Ordering Paragraph 4.[7]

2. The Commission should restate PG&E's office closure requirements to be identical to those of Southern California Edison Company (SCE), as stated in D. 98-07-077, with an additional requirement to address attempts to obtain shared office space.
3. PG&E should determine customer needs and satisfaction regarding Local Offices and Pay Stations by:
   - ❑ Conducting a regular survey of customers who interact in person with PG&E Local Offices and/or Pay Stations to determine customer satisfaction with the facilities and get suggestions for improvement, <u>and</u>

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[5] *Id.*, Sec. 4, p. 6, and Sec. 7, p. 8.
[6] *Id.*, Sec. 7, p. 42
[7] *Re Southern California Edison Company* [D. 98-07-077] (1998) 81 CPUC2d 175, 184-185.

- ❑ Conducting a sample survey of customers who do not currently pay in person about Local Offices and Pay Stations to determine need and desire for more locations and desired features of facilities.

4. PG&E should investigate the cost and benefit of having direct-connect, Call Center phones at all Local Offices not so equipped.

The Network Study

The Network Study was extremely detailed, exploring all aspects of PG&E's in-person customer service delivery network. The study found inefficiencies or inadequacies in several areas, such as customer education, activity measurement, customer preference assessment and Local Office operations. To accomplish the improvements it determined necessary, the Network Study recommended an implementation plan as follows:

<u>Phase I</u>

- Develop customer educational materials
- Institute employee incentive program
- Begin measurement of customer service office activities
- Reopen exterior drop boxes
- Survey of customer preference on hours of operation
- Implement pay stations in recommended customer service office locations
- Begin closure of offices
- Based on results of customer preference survey, downsize hours in offices

<u>Phase II</u>

- Establish retail store concept
- Implement Pay-As-You-Go concept[8]

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[8] Network Study, Sec. 7, p. 44.

The Network Study's recommendation categories for location-based customer service are:[9]

Status Quo – No change recommended to current office

Transformation – Expansion and enhancement of service through the addition of a pay station and a kiosk

Downsize – Reduce hours of operation at the business office

Closure – Close customer service office

Void – Add new customer service office(s)

A more detailed description of these categories and the Network Study's rationales for the recommendations is appended as Appendix 9-A-1 to this chapter.

The numbers of local business offices the Network Study puts in each category are:

Status Quo – 22

Transformation – 21

Downsize – 28

Closure – 12

Void (add) – 7

PG&E was in the process of implementing at least one of the recommendations in the Network Study when the energy crisis and PG&E's bankruptcy brought a halt to the activity. PG&E has not since pursued any of the recommendations of the study but has indicated that it intends to consider doing so in the future.[10] ORA encourages PG&E's efforts in this regard.

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[9] *Id.*, Sec. 1, p. 4.

[10] PG&E response to ORA Data Request #1, dated April 5, 2002, Q. 7, and to ORA-DR-041, Q. 1, dated October 11, 2002. ORA "Data Request #1,"

III. PG&E'S CUSTOMER SERVICE NETWORK

A. Local Offices

PG&E operates 84 Local Offices throughout Northern and Central California. For comparison, SCE, a similarly-sized utility, operates 10 Local Business Offices. PG&E's Local Offices are either PG&E-owned or leased facilities or are facilities shared with other business entities. All of PG&E's Local Offices are open Monday through Friday. There is no weekend service. The hours of operation for most (73) offices are between 8:00 or 8:30 a.m. and 4:00, 4:30 or 5:00 p.m.; 11 offices operate between 9:00 a.m. and 4:30 or 5:00 p.m.[11] English is the only language spoken at Local Offices, although assistance is available for non-English-speaking customers through the Call Center. Customers can pay a customer service representative in a bank teller-type transaction or deposit payments in a Drop Box, either inside or outside most Local Office locations. Drop Box payments are typically collected during or at the end of the day and usually credited to the customer's account the next business day.

Payment activity at Local Offices declined significantly in 1999 and again in 2000, but reverted back to almost the 1999 level in both 2001 and 2002. In 1998, Local Offices processed 6.45 million payments. In 1999, that figure was 4.82 million, a drop of 25.2%. 2000 saw a further drop of 16.0% to 4.05 million payments. However, in 2001, payment activity at Local Offices increased to 4.75 million, an increase

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issued March 20, 2002, is outside of the normal, numbered DR series established in this proceeding.

[11] PG&E response to ORA Data Request #1, Q. 6, dated April 5, 2002.

of 17.1%, and in 2002 increased slightly again by 0.36% to 4.77 million.[12] Table 9-A-1 below graphically shows the pattern of Local Office payment volumes for the last five years, along with corresponding volumes for Pay Stations and total in-person payments.

In 2001, 55% of customers who paid bills at Local Offices paid by check; 45% paid in cash.[13]

Although Local Offices perform other functions, PG&E does not track them. The Network Study states that PG&E estimates that approximately 10% of Local Office time is spent on activities other than payment processing. The Network Study also states that other utilities' networks expend approximately 5% of their efforts on transactions other than payments.[14] However, PG&E indicated in a data request response that 30% of time in Local Offices is spent on transactions other than payments -- 20% service requests and 10% credit inquiries.[15] The actual proportion of these activities is not certain at this time.

B. <u>Pay Stations (payment agents)</u>

PG&E contracts with American Payment Systems for in-person payment service at various locations throughout PG&E's service territory. Currently, 367 Pay Station agents take in-person payments for PG&E bills.[16] The types of facilities vary, but most are retail locations, such as local grocery stores, mini-marts, check-cashing businesses, supermarkets, pharmacies, video stores, liquor stores and banks.

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[12] PG&E response to ORA-DR-346, Q. 1, dated April 4, 2003.
[13] PG&E response to ORA-DR-241, Q. 5, dated February 4, 2003.
[14] Network Study, Sec. 3, p. 7.
[15] PG&E response to ORA Data Request #1, Q. 11, dated April 5, 2002.
[16] *Id.*, Q. 4.

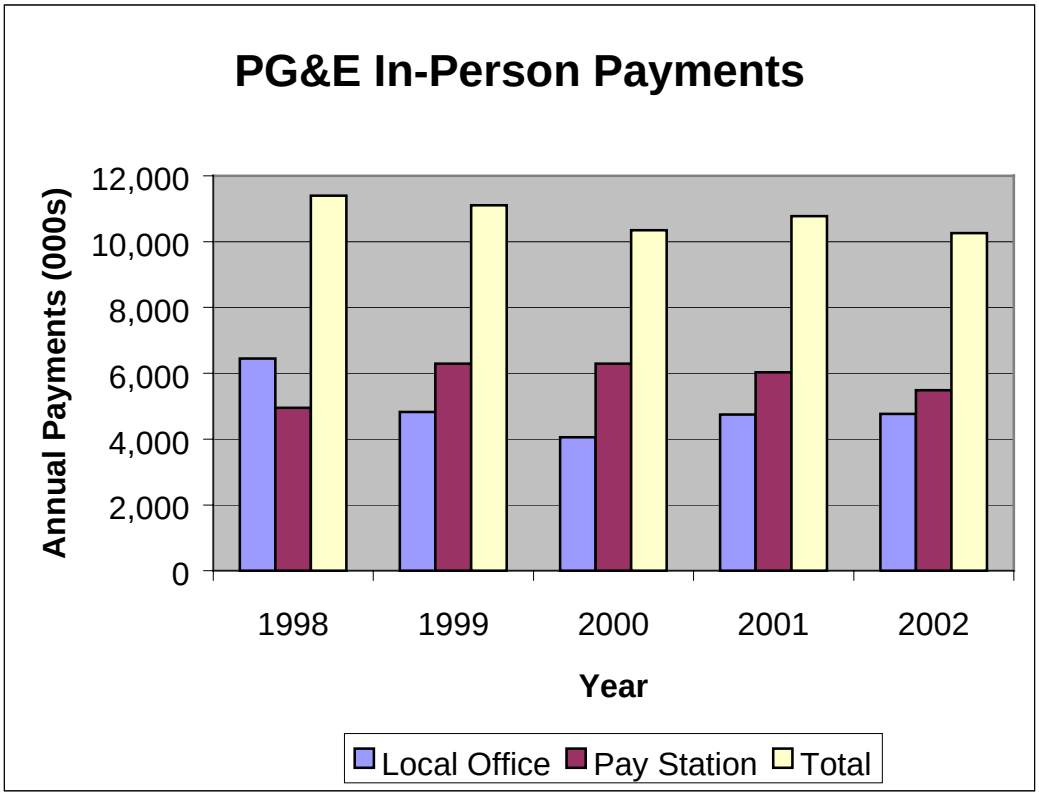
New Pay Stations are added if Local Office payment traffic appears to warrant a new site in the area or to replace Pay Stations that stop taking PG&E payments. The number of Pay Stations has remained fairly constant, in the 360-plus range, for the past five years or so. For comparison, SCE has about 375 payment agent locations.

Total payment activity in the Pay Stations has decreased in the last two years, 2001 and 2002, and for the past five years the pattern of payment volumes displays an inverse relationship to those in the Local Offices. In 1998, Pay Stations processed 4.95 million payments; in 1999, that volume increased by 26.9% to 6.285 million. In 2000, Pay Station volume increased negligibly another 0.3% to 6.287 million payments. 2001 saw a 4.2% decline in payment volume to 6.02 million payments, and 2002 recorded a more significant decline of 8.5% to 5.49 million payments.[17]

Table 9-A-1 below graphically shows the payment activity at both Local Offices and Pay Stations, along with the total in-person payments for the years 1998 through 2002. As the table shows, total in-person payment activity has generally declined over the past five years.

[17] PG&E response to ORA-DR-346, Q. 1, dated April 4, 2003.

a. TABLE 9-A-1



In a reverse pattern from that observed in Local Offices, most Pay Station customers pay their bills in cash. In 2002, over half (56%) of Pay Station customers paid in cash; the rest (44%) paid by check or money order.[18]

Pay Stations are more generous than Local Offices in terms of days of operation and open hours. Most Pay Stations are open weekends, whereas Local Offices are not. Although they are open more hours each day, Pay Stations' extended schedules generally extend more into the evening hours than early morning. Relatively few locations open prior to 8:00 a.m.[19]

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[18] PG&E response to DR ORA-241, Q. 6, dated January 30, 2003.
[19] PG&E response to ORA Data Request #1, Q. 6, dated April 5, 2002.

PAY STATION DAYS OF OPERATION[20]

16.3% open 5 days per week (Monday through Friday, one closed Wednesday & Sunday)

43.1% open 6 days per week (Monday through Saturday)

40.6% open 7 days per week (Monday through Sunday)

PAY STATION HOURS OF OPERATION[21]

Morning:

14.2% open prior to 8:00 a.m.

3.0% open prior to 7:00 a.m.

1.1% open prior to 6:00 a.m.

Evening:

73.0% open after 5:00 p.m.

45.2% open after 6:00 p.m.

28.9% open after 7:00 p.m.

16.9% open after 8:00 p.m.

8.7% open after 9:00 p.m.

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[20] *Id.*
[21] *Id.*

LANGUAGES SPOKEN AT PAY STATIONS[22]

55.3%	English only
37.3%	English & Spanish
3.5%	English & Chinese, Cantonese or Mandarin
2.5%	English & Punjabi
1.9%	English & Vietnamese
1.6%	English & Persian (Farsi)
1.1%	English & Arabic
1.1%	English & Hindi
1.1%	English & Korean
1.1%	English & Tagalog
0.5%	English & Italian

In addition to English, the following languages are spoken at only one Pay Station: Cambodian, Indonesian, Japanese and Russian.

The extended days and hours of operation at Pay Stations, along with language facility at many locations, offer greater bill-paying convenience to customers compared with the same service offered at Local Offices.

C. Customer Call Center

Although not an in-person transaction avenue, and not a payment collection facility, PG&E's Call Center handles customer transactions for PG&E customers systemwide. It is important because of its capacity to handle transactions that Local Offices also handle, such as billing inquiries, service initiation and customer education, among others. The difference between the Call Center and the Local Offices is that the Call

[22] PG&E response to ORA DR-241, Q. 9, dated January 30, 2003.

Center conducts all of its business by telephone, whereas Local Offices conduct business with customers in person.

Both of these customer service "delivery channels" have their strong points and weaknesses. The Call Center is a convenient channel for customers who are comfortable conducting business over the phone. It is generally quick and efficient in fielding and disposing of customer calls. The Local Office is convenient and preferable for customers who want to speak with a "live" person and get personal attention, including receiving printed materials on subjects related to utility service. In many ways, the Call Center can be a substitute for the Local Office.

IV. DISCUSSION/ANALYSIS

A. Measurement of Local Office transactions

PG&E does not track transactions at its Local Offices other than payments. The Network Study noted this fact and recommended measuring all activities to help identify areas for improvement.[23] ORA concurs with this recommendation. Without a complete assessment of activity, PG&E cannot present a complete picture of the Local Office functions. Measuring and reporting only payment activity understates the value of the Local Office to customers and hinders analysis of Local Office operations. PG&E should implement a program to measure all of its Local Office activities.

1. Reopen closed Drop Boxes

Drop Boxes are an important alternative payment option, offering increased convenience and flexibility for Local Office staff and the

[23] Network Study, Sec. 7, p. 39.

customer. Currently, payments deposited in Drop Boxes may not be processed and posted to the customer's account until the next day. Given the fact that a substantial portion of in-person payments are "last-minute" to prevent discontinuance of service,[24] rapid processing of such payments is critical. The Network Study recommends that payments deposited in Drop Boxes before 2:00 p.m. should be processed and posted to the customer's account on the same day, with signage to that effect on the Drop Box.[25] ORA concurs with this recommendation.

2. Educate customers about payment options and encourage behavior change

PG&E asserts that it provides information to customers about available payment options. PG&E states that it encourages customers to pay their bills by mail by providing return envelopes with billing statements, encourages customers to use electronic payment options via bill inserts and Web site promotions, and shares these alternative payment options with customers visiting Local Offices.[26]

Of all of the available payment options, payment at Local Offices is the most costly to PG&E. The emphasis for the customer education task should be on customers who pay their bills at Local Offices, particularly those who pay by check. ORA has visited Local Offices and viewed their information racks. Although very little material was in evidence, ORA found a brochure entitled "Automatic Bill Payment," explaining the automatic debit program option. No other material describing payment options was on display, and customer service staff did not engage in discussion nor disseminate information about payment

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[24] *Id.*, Sec. 4, pp. 1 and 8.
[25] *Id.*, Sec. 7, p. 40.
[26] PG&E response to ORA DR-241, Q. 12, dated January 30, 2003.

alternatives. ORA recommends that PG&E increase its efforts to educate its customers, particularly its Local Office customers, about alternative payment options and encourage movement to those that are less costly.

3. Add self-service facilities

In 1999, PG&E initiated a pilot program to implement unattended payment machines in five locations. The energy crisis, PG&E's subsequent bankruptcy and a machine vendor problem caused that project to be terminated. ORA recommends that PG&E attempt to reinstitute a pilot program for self-service payment facilities in areas identified as candidates for them.

4. New Local Offices

The Network Study asserts that little necessity exists to add new location-based (those with a physical site) offices and payment agents. However, the study recommends adding seven new Local Offices to satisfy what is stated as PG&E's interest in implementing a "retail store concept." Accordingly, the study identifies seven sites as candidates for new Local Offices. These sites have a high concentration of PG&E households, positive daytime activity, high concentration of retail establishments and a high concentration of late-paying households, specifically those having their service shut off.[27] All seven sites are in super regional shopping malls.

Although the Network Study appears to recommend new "offices" under the retail store concept, conversation with PG&E staff elicited that the additions contemplated were not Local Offices as such; rather, they were kiosks, either staffed or unstaffed, and/or automated facilities, akin to automatic teller machines, located in large retail centers. The Network

[27] Network Study, Sec. 7, p. 10.

Study, however, does not make that distinction clear. ORA suggests that reassessment of the Network Study's findings and recommendations under current conditions would lead to selection of the appropriate options.

The Network Study was conducted using data from 1998 through 2001. The shopping malls identified as potential Local Office locations were in some cases in the planning or construction stages at the time of the study. Some of the data may be stale and in need of refreshing. On the other hand, some of the areas surrounding the identified sites are still developing significantly, which may suggest a need for additional company presence. PG&E's retail store concept may have merit and deserve consideration. ORA recommends that PG&E reassess the Network Study's results using the latest information available, evaluate the customer benefits of new office locations and enhance its network with new facilities as appropriate.

5. Closing Local Offices

The Network Study recommendation most likely to lead to controversy is the recommendation to close 12 of PG&E's Local Offices. The sensitive nature of this recommendation is demonstrated by various utility office closures in recent years, but exemplified by PG&E's closure of its Corcoran office in 1999. The company received such intense community opposition to the closure that it subsequently reopened the office. The lesson learned from this experience underscores the importance of following the Commission's direction regarding business office closures.[28]

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[28] This is not to imply that PG&E did not follow proper procedures in the Corcoran case.

The Commission's criteria for utility office closures are stated in several Commission decisions, but in best detail in D. 98-07-077. Although that decision was issued in the context of a Southern California Edison Company proceeding, the criteria should be applicable as minimums to all utility office closures.[29] D. 98-07-077 requires:

> 1. Notices of proposed office closures must be provided by mail, posting, and published notices. Notice must be given 60 days prior to an advice letter filing notifying the Commission of a planned closure. All notices must be multilingual and should include prominent statements regarding office closure and the Commission's 800-telephone number.
> 2. Edison should compile responses [from the public to the published notices] and include them with the advice letter filing with the Commission.
> 3. Advice letters must give a 60-day notice of proposed closure and must contain accurate listing of authorized payment agency (APA) locations to serve areas formerly served by the business office.
> 4. Advice letters must demonstrate a rational basis for the closure and no discriminatory impact of closure upon poor, elderly, minority, or rural customers.30

The decision containing PG&E's office closure requirements is less detailed yet essentially the same. D. 95-12-055 states:

> PG&E shall submit an advice letter no less than 60 days prior to the date it proposes to close a business office. The advice letter shall describe the customer notice it provided regarding a proposed closure, the service alternatives available to local customer, and the response it received from customer and local officials following its notice. PG&E may not close

[29] ORA notes that Southern California Gas Co. is specifically required to file a formal application to request office closures, per D. 92-08-038.

[30] 81 CPUC2d 175, 185.

> any business office without prior Commission authorization by resolution or order.[31]

It is ORA's understanding that PG&E looks for shared locations when considering locating or relocating its Local Offices. Shared locations entail shared rents and effect savings to PG&E and its customers. For Local Offices not already shared, ORA recommends that PG&E make every effort to obtain shared relocations as a first alternative to office closure. Such efforts should be described in any advice letter seeking authorization to close a Local Office.

To avoid any misunderstandings or complications from differences in wording between the PG&E and SCE requirements, ORA recommends that the Commission restate PG&E's office closure procedures to be identical to those of SCE, with the addition of noting efforts to obtain shared locations.

6. Customer Satisfaction with Local Offices and Pay Stations

In 1999, PG&E conducted a customer satisfaction survey (CS Survey) focusing on Local Offices and Pay Stations.[32] The CS Survey showed that customers were generally and equally satisfied with both Local Offices and Pay Stations. The purpose of the CS Survey was to compare and contrast satisfaction levels, relative to bill-paying activity, between Local Office and Pay Station customers. From a sample of 5000 customers that PG&E provided, Opinion Dynamics Corporation completed 542 interviews with customers who had recently made in-

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[31] Ordering Paragraph 23, *Re Pacific Gas and Electric Company* [D.95-12-055] 63 CPUC2d 570, 636.

[32] PG&E Revised response to ORA-DR-241, dated March 28, 2003, but effectively received April 1, 2003.

person bill payments -- 271 from Local Offices and 271 from Pay Stations.

Although the CS Survey found no significant difference in satisfaction between the Local Offices and Pay Stations, its results revealed areas that could be improved. For example, 25.4% of respondents said parking was less than "good" ("fair" and "poor") at their payment location.[33] Waiting in line could be a concern, as 23.1% of respondents rated their experience as fair or poor in this category.[34]

The CS Survey results also supported some of the findings in the Network Study, such as that a significant number of Local Office customers would be likely to switch to Pay Stations,[35] and that there is a lack of customer awareness of available payment options.[36]

Although PG&E conducted one customer satisfaction survey, approximately four years ago, it appears that PG&E conducts no regular customer satisfaction or customer preference surveys specific to its Local Offices or Pay Stations.[37] Customer behavior is dynamic; preferences change. The population is dynamic; customers move both into and out of geographic areas bringing with them new needs and desires. Without regular monitoring surveys, it is not possible to say whether customers who use in-person facilities find those facilities acceptable or think they should be changed in any way. For example, relatively few Pay Stations are open prior to 8:00 a.m. Their open hours extend beyond Local Office hours mostly in the evening. If the intent is to encourage customers to gravitate toward less costly, more convenient payment options, then a

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[33] CS Survey, Appendix D, p.6.
[34] *Id*., p. 9.
[35] CS Survey, Appendix D, p.11, and Network Study, Sec. 1, p. 6.
[36] CS Survey, Appendix D, pp.14-15, and Network Study, Sec. 1, p. 6.

wider range of open hours at Pay Stations may be called for. Customers paying their bills at Local Offices might move to the less costly Pay Stations if they were open earlier hours. Without a customer survey to elicit customer preferences, it is impossible to know whether this is so.

ORA recommends that PG&E conduct regular surveys of its customers who use its local offices and pay stations to determine what customers think about the service they receive and the facilities provided. Such surveys should be conducted at least annually, or, as SCE does, on a continuous basis and summarized annually. Adding a survey area and questions about Local Offices and Pay Stations to PG&E's existing Quality of Service Evaluation or its Customer Opinion Surveys[38] may be ways to accomplish this task.

7. Direct-connect Call Center telephones

All Local Offices have telephones capable of connecting with the Call Center. However, it is not always apparent that a telephone may be available for customer use.[39] A dedicated telephone, conspicuously signed and in a convenient location in a Local Office waiting area could be useful when there are waiting lines and a customer wishes to conduct a transaction other than bill payment or the customer service representative at the counter is unable to meet the customer's need.[40] ORA recommends that PG&E evaluate the efficacy of making an existing telephone conveniently and conspicuously available to

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[37] PG&E response to ORA DR-320-05, March 7, 2003

[38] PG&E-3, Ch. 3, p. 3-17, describes these surveys.

[39] The Richmond Local Office has no telephone in the waiting area. If a telephone is available for customer use, that fact is not apparent.

[40] The Local Office in San Francisco's Mission District provides a good example of this service, having three dedicated telephones, although there are no signs indicating their purpose.

customers or installing dedicated, direct-connect telephones for the purpose of contacting PG&E's Call Center at Local Offices that do not currently have such telephones.

8. Payment options

a. Payment by Mail (Pay-By-Mail)

To pay the bill by U.S. mail, the customer may send a personal check, cashier's check or money order with the bill payment stub in the envelope provided with the bill.

Payment by mail is by far the most popular payment method with about 67.9% of payments in 2002 processed by PG&E's mail payment processing center.[41] As a percent of total payments, payments by mail have declined almost 1% per year for the last four years, 1999 through 2002.[42] The average cost to process a mail payment is $0.10.[43]

b. Payment in Person

To pay the bill in person, the customer may visit the nearest Local Office or authorized Pay Station (or payment agent) and pay by cash, check or money order. Payment at Local Offices can be made at a counter attended by a PG&E customer service representative or in some or most offices at a self-service Drop Box. Drop Box payments must be made by check or money order; cash payment is not allowed. The customer receives a receipt from the counter, but not from the Drop Box option.

In-person payments are the second most popular payment option with about 18% of all payments processed by a Local Office or Pay Station. Pay Stations currently process about 54% of in-person

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[41] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[42] *Id.*
[43] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.

payments, while Local Offices process about 46%.[44] As a percent of total payments, in-person payments, like payments by mail, have decreased by three-quarters of a percent per year for the last four years, 1999 through 2002.[45] PG&E's average handling cost per payment at Local Offices is $2.91, and $0.54 at Pay Stations.[46]

c. Payment via Automated Payment Processing

EFT -- Electronic Funds Transfer enables a debit from checking or savings account initiated by the customer through various means, including PG&E's Customer Service Online (CSOL) feature on its website. Payments via this option are on the increase; 2.9 million payments, 5% of total payments, were made in 2002, almost double the 1999 level.[47] PG&E's cost per EFT transaction is $0.16.[48]

EDI -- Electronic Data Interchange is an automated, computerized billing information and payment system utilized primarily by large corporations. This option, generating 484,509 payments in 2002, accounts for just less than one percent (0.8%) of total payments.[49] PG&E's cost per EDI transaction is $1.99.[50]

APS -- Automated Payment Service is a direct debit from a customer's checking or savings account paid automatically to PG&E each month. In 2002, 4.2 million payments, 7.1% of total payments, were made by APS.[51] PG&E's cost per APS transaction is about $0.18.[52]

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[44] Derived from PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[45] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[46] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.
[47] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[48] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.
[49] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[50] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.
[51] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[52] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.

d. Pay-By-Phone

With this payment option, the customer can call PG&E's Call Center and authorize payment with a credit card or ATM card. The card issuer charges the customer a fee for this service. For credit card payment, the charge is $6.95 per payment; for ATM payment, the charge is $2.95.[53]

Less than one percent (0.9%) of payments are made through this option, which generated nearly 550,000 payments in both 2001 and 2002.[54] PG&E's cost is $1.28 per phone transaction.[55]

e. Pay-By-Home-Computer

This payment option enable customers to pay via PG&E's website, pge.com, using PG&E's Customer Service Online (CSOL) feature. The customer must make arrangements with a bank or other financial institution and register with CSOL to activate this payment option. Payments are not automatic; action by the customer is required. Payment is effected when the customer logs in to CSOL, accesses his or her account and directs that bill payment be made. There is no charge for this option.

In 2002, this option generated 247,387 payments, 0.4% of total payments, its use more than doubling from 2001.[56] PG&E's cost for the website option is $0.56 per transaction.[57]

f. Balanced Payment Plan

This payment option is available only to residential customers and in conjunction with any of the other payment options. It is not a method

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[53] Per call to PG&E's Call Center, April 8, 2003.
[54] PG&E response to ORA DR-346, Q. 1, April 4, 2003.
[55] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.
[56] PG&E response to ORA DR-346, Q. 1, April 4, 2003.

of payment; rather, it is a billing method that allows the customer to pay the yearly bill in equal monthly payments, thereby enabling the customer to budget for energy costs. This feature is useful for customers who have high summer or winter bills and want to spread those bills evenly over an entire year.

Under the Balanced Payment Plan, the monthly bill is based on the customer's energy usage for the prior 12 months. The annual cost for that usage is calculated using current rates and divided by 12 to arrive at the monthly bill. The customer's meter is read every month, and actual usage is shown on the monthly bill, but the customer pays the balanced payment amount. The customer's account is reviewed every four months and may be adjusted up or down for any over- or under-billings that may be evident. If after 12 months on the plan the customer's account has a balance due or a credit balance, that amount will be spread over the next 12-month cycle. The customer also has the option of settling the account at the end of a 12-month cycle.

There is no charge to the customer for utilizing this plan. PG&E's cost per payment for this feature depends on the payment method the customer uses.

9. Other Services

Local Offices provide services other than payment transactions. Among those other services are administrative services, account servicing and customer education – functions such as service initiation, arranging payment plans, taking of deposits, reestablishment of service, answering billing and credit inquiries and informing customers of billing options, payment methods, energy conservation and energy efficiency.

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[57] PG&E response to ORA DR-241, Q. 11, Supp 01, February 12, 2003.

It is not clear how much activity occurs at Local Offices other than payment activity. As indicated earlier in this chapter, although the Network Study alludes to a PG&E estimate of 10% and other utilities' efforts at 5%, PG&E's 2002 estimate that approximately 30% of services requested were other than payments[58] raises a question about the actual level of that activity.

Pay Stations provide only payment collection services, including collecting deposits to reestablish service. PG&E may provide collateral material for dissemination by the Pay Station agent for customer education, but that is not always apparent.

V. CONCLUSIONS

PG&E's Network Study and Customer Satisfaction Survey give insight into the operations of Local Offices and Pay Stations and the methods of payment its customers use to pay their monthly bills. PG&E's Local Offices are currently utilized by significant numbers of customers, some more than others, and that utilization has remained relatively constant, with some variation, over the last four years. Most of the customers who patronize these offices do so to pay their bills. Their reasons for doing so in person are varied and personal. Keeping these offices open is very important to many of these customers. However, both the Network Study and CS Survey indicate that a significant number of Local Office customers do not know about alternatives such as Pay Stations and electronic bill payment options. These findings present an apparent opportunity for PG&E to educate its customers and motivate them to move to lower-cost payment options.

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[58] PG&E response to ORA DR #1, Q. 11, dated April 5, 2002.

PG&E should survey its customers to determine optimal deployment of its Local Office and Pay Station resources. Educating its Local Office and Pay Station customers about lower-cost payment options and encouraging them to move toward those options is important to achieving lower costs overall in the billing and collection operation. In any event, PG&E should exercise great care and sensitivity when considering closing Local Offices. It is the community that is at issue – both PG&E's and the customers'. ORA recommends that PG&E consider implementing the recommendations in the Network Study and that the Commission adopt ORA's other recommendations in this chapter.

APPENDIX 9-A-1

Potential Actions Affecting Local Offices

The Network Study describes the rationales for each of its recommendations affecting PG&E's Local Offices:

Status Quo – No change

A status quo recommendation reflects adequate coverage within the market or recent changes within the market prevent the ability to establish rationale for change. These offices offer adequate service to meet the needs of the market. No change is recommended at these facilities with the exception of the addition of print merchandising and educational materials focusing on educating customers on delivery choices available.[59]

Transformation – Adding nearby pay stations and self-service kiosks

Transformations are recommended in sites with high volumes in markets where the addition of options will most benefit both the customer and PG&E. In addition, reduction of service in the surrounding area may also impact the need to expand service in the remaining locations. In these areas, the primary destination point in the area, or the location demonstrating the strongest customer draw was chosen for transformation.

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For those recommended sites that could best support pay station technology, areas have been chosen having customers who are less "location dependent" (customers dependent on a physical site) and are more likely to prefer a more self-service oriented channel such as a pay station for bill payment and other routine functions. These customers are also more likely to answer

[59] Network Study, Sec. 7, p. 6.

favorably to questions regarding the ability to perform transactions at non-attended or self-service facilities throughout the study area.

Finally, transformation of offices should occur prior to actions in the neighboring locations.[60]

<u>Downsize</u> – Reducing hours of operation

Downsizing refers to the reduction of hours of operation within the recommended office. Though an office may have low transaction volume levels and there is no demonstrated demand for a staffed, location-based (those with a physical site) servicing in the area, the lack of alternative sites in the market prohibits the closing of the office. Downsizing is recommended to reduce the office hours to a level that better reflects the demands of the market. In addition, several offices recommended for downsizing are located in markets where expansion of other PG&E offices is recommended and migration patterns are strong. In these markets, offices that demonstrate the weakest transaction volume levels are recommended for downsizing.

Please note that any reduction in hours should only occur after a survey of customer preference is conducted. Downsizing should be preceded by a survey of customer preference for hours of operation. In addition, all downsized offices are recommended to include the addition of educational materials in print form to assist in informing customers of choices available.[61]

<u>Closure</u> – Closing Local Offices

Closure recommendations are driven, in large part, by the low demand for staffed location-based (those with a physical site) service demonstrated by the transaction volumes. The existence of alternative sites in the market is also considered; ensuring customers are not left without attended delivery points

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[60] *Id.*, p. 7.
[61] *Id.*, p. 8.

available to them. Customer service quality will not be diminished by recommended closures, as coverage remains strong. In addition, expansion and enhancement of service within the market or in adjacent markets provides further support for this action.

Closure recommendations are primarily in the smaller market areas where alternative sites are within close proximity. The closing of offices should not occur until adjacent transformations have been completed.[62]

<u>Void</u> – Add Local Offices

PG&E has excellent coverage throughout the study area with the current configuration of location-based (those with a physical site) offices and payment agents; little necessity to add additional facilities exists. However, PG&E has expressed an interest in implementing a retail store concept. This proposal creates an opportunity to add additional facilities in choice areas of the study area …. Implementing the retail store initiative in areas in super regional malls within high retail activity areas is thought to offer the best environment to introduce this new concept.

Seven different sites are identified throughout the network, each meeting the following criteria:

- High concentration of PG&E households.
- Moderate to high household penetration.
- Positive daytime activity.
- High concentration of retail establishments.
- High concentration of late paying households, specifically those having their service shut off.[63]

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[62] *Id.*, p. 9.
[63] Id., p. 10.

CHAPTER 9-B

QUALITY ASSURANCE PROGRAM

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) reports on its existing Quality Assurance Program (QAP) of service guarantees in PG&E-3 Chapter 9. The Commission adopted this program in Decision 00-02-046 in PG&E's 1999 General Rate Case (GRC), to compensate customers when PG&E fails to meet any of seven specific service standards, and to provide an incentive for PG&E to meet its commitments in the covered areas.[1] PG&E's testimony in this GRC does not propose changes to the existing QAP, which was implemented on June 16, 2000.

This chapter contains the Office Ratepayer Advocates (ORA's) analysis of PG&E's existing Quality Assurance Program, along with recommendations for several changes to the guarantees, credit amounts, and reporting requirements under this program. The resulting proposal is consistent with the Service Guarantee Program ORA recommended in the current Southern California Edison (SCE) GRC proceeding, Application 02-05-004.

II. SUMMARY/RECOMMENDATIONS

In adopting PG&E's Quality Assurance Program in D. 00-02-046, the Commission established reporting requirements "to determine its efficacy, and potential for abuse," and stated the intention to "consider modifications to the program in the next GRC."[2] Based on the information currently available on

[1] D. 00-02-046 p. 92
[2] D. 00-02-046 p. 93

PG&E's QAP program,[3] ORA recommends several changes to this program. Specifically, ORA recommends the elimination of the one existing guarantee related to response to requests for emergency services, minor changes in two other guarantees related to investigating non-emergency situations and resolving customer complaints, and the adoption of a single, consistent credit amount for all remaining guarantees. ORA also recommends the addition of two new service guarantees in areas related to basic aspects of customer service, and suggests changes to the existing reporting requirements to increase the reports' usefulness. The following table summarizes the service guarantees in PG&E's existing Quality Assurance Program and enumerates ORA's proposed changes.

[3] See especially letters from PG&E to Paul Clanon, dated January 3, 2002, and January 14, 2003 reporting results of PG&E Customer Service Guarantee Program; also, PG&E response to DR-ORA-326 question 1a.

1 **Table 9B-1: Comparison of Existing and Proposed Guarantees:**

Existing		**Proposed**	
Standard PG&E will:	***Credit***	***Standard*** PG&E will:	***Credit***
1: Meet agreed appointment times	$25	***1:*** same	$50
2: Investigate non-emergency situations (check meter) within a time frame acceptable to both the customer and PG&E.	$25	***2:*** Investigate non-emergency situations (check meter) and communicate results to customers within 7 days of a customer request.	$50
3: Respond immediately (usually within 2 hours) to a request for emergency service.	$100	*Eliminate*	*Eliminate*
4: Communicate to the customer within three working days the actions PG&E will take to resolve a complaint referred to PG&E by the Commission, and communicate the complaint's resolution to the customers within 5 working days	$25	***3:*** Decide on a course of action to resolve a complaint and communicate it to the customer within 3 working days, and communicate the complaint's resolution to the customer within 10 working days, or 30 working days when an off-site meter test is required or an on-site home audit is requested.	$50
5: Meet the agreed date for installing a new meter and turning on service for a customer	$50	***4:*** same	same ($50)
6: Respond to service interruptions within 4 hours after receiving a customer report by either restoring service or informing the customer of when they can expect service to be restored	$25	***5:*** same	$50
7: Restore service within 24 hours (for non-emergency events)[4]	$25 for each 24 hours without service	***6:*** same	$50 for each 24 hours without service
8: none	none	***7:*** Provide at least three days notice of a planned interruption in service	$50
9: none	none	***8:*** Issue an accurate first bill to a new customer account within 60 days of service initiation	$50

[4] Some customers would receive credits for outages caused by storm emergencies under PG&E's new "Safety Net" program.

The first six guarantees in ORA's proposal are already in place for PG&E, some with minor differences in wording or credit amounts. The proposed increases in some credit amounts to $50 will simplify the program by providing a single, consistent credit for all guarantees. This increase is further warranted based on the apparent success of SCE's former voluntary program, which had credits of $50 for all covered guarantees, in decreasing the number of claims incurred over the course of the program. The reports on PG&E's QAP do not show clear trends of increasing or decreasing claims. There is no evidence to suggest that the existing credit amounts, which range from $25 to $100, are creating perverse incentives, the concern expressed by the Commission[5] in adopting credit amounts that were lower than the credits under SCE's voluntary program or the credits proposed by ORA in PG&E's last rate case. The proposal summarized above, which mirrors ORA's proposal in the SCE GRC, would make the credit amount for all guarantees consistent at $50.

The monthly reports PG&E files on its existing service guarantees do not show a clear trend of increasing or decreasing claims under this program. There are many possible reasons for this, but future reports should provide more information to allow a thorough evaluation of whether PG&E maintains or improves its service to customers in the guaranteed areas. PG&E should continue to submit reports showing the number of claims made, claims paid, and amounts of money paid under each guarantee for each month. However, ORA recommends filing future reports quarterly rather than monthly to reduce duplication. In addition, PG&E should submit more detailed information on the locations (by PG&E division) where the credits are incurred. PG&E should also provide text along with all these

[5] D. 00-02-046, p. 92

tables to explain any material variations in the number of claims over time or in different locations.

This proposal is designed to compensate customers for inconvenience when PG&E fails to meet a covered service commitment, while at the same time providing an incentive for PG&E to maintain high-quality customer service. Credits under the program should continue to be funded by shareholders in order to provide PG&E with an incentive to reduce their total claims. PG&E should work with ORA and other interested parties to define any specific assumptions for the application of new or revised guarantees and exceptions to those guarantees, as well as to develop tracking and reporting procedures that can be easily verified and audited.

III. DISCUSSION/ANALYSIS

A. Background

In September 1995, SCE began guaranteeing three services to their customers. Under this voluntary program, SCE guaranteed that it would do the following: 1) install new meters and initiate electric service to customers by the agreed date; 2) respond to service disruptions within four hours of customer calls reporting the outage, either by restoring service or by notifying the customer of when service would be restored; and 3) restore service within 24 hours of a reported disruption. Under normal circumstances, SCE committed to pay customers $50 if they failed to meet

any of these guarantees.[6] SCE reduced the claims made and paid fairly consistently throughout its program.[7]

After SCE instituted this program, the Commission adopted similar programs for SDG&E and PG&E. SDG&E's program was adopted as part of a settlement in their last PBR proceeding. Decision 99-05-030 requires SDG&E to provide credits to its customers if they miss scheduled appointments or fail to turn on a customer's electric or gas service on the agreed date. Under SDG&E's program as adopted by the Commission, customers receive $50 bill credits for missed appointments, and receive credits in the amount of the service establishment charge ($15 for electricity or gas, $30 for both) if SDG&E fails to initiate service on time.

PG&E's current program, adopted in its last GRC decision, D. 00-02-046, requires it to guarantee a variety of services with customer credits of between $25 and $100. The services under the PG&E program include the services within the SCE and SDG&E programs and several others. PG&E implemented its program in June 2000 after discussions with ORA, The Utility Reform Network (TURN), and the Coalition of California Utility Employees, as well as the CPUC Energy and Consumer Services Divisions.[8] The final implementation plan, as described in a letter dated June 16, 2000, to the Commission's executive director, explains the assumptions defining what is being guaranteed and exceptions for certain circumstances beyond PG&E's control.

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[6] SCE response to DR-ORA-055 question 3 in A. 02-05-004: attached brochure titled "Service Guarantee," apparently revised in 1996.

[7] See data in SCE response to DR-ORA-055 question 5 in A. 02-05-004.

[8] PG&E letter to Wes Franklin dated June 16, 2000, explaining implementation of Quality Assurance Program adopted in D. 00-02-046.

In adopting service guarantees for PG&E, the Commission recognized that they are "a self-enforcing mechanism that may create a significant incentive for PG&E to meet the standards,"[9] but reduced the credit amounts proposed by ORA for some of the guarantees out of concern that ORA's recommended levels "may be excessive, and may create perverse incentives for customers."[10] PG&E's compliance reports on its program do not show any obvious trend of increasing or decreasing claims. Because this program has only been in effect for two and one half years and the number of claims varies widely from month to month, however, such a trend might be difficult to detect. From the data to date, it does not appear that PG&E's program has encouraged customers to make unnecessary requests for guaranteed services or frivolous claims for credits. For most guarantees, fewer claims were made in 2002 than in 2001, the only two full years of the program so far.[11] Based on this limited experience, the service guarantee programs may provide the intended incentive for PG&E envisioned by the Commission in D. 00-02-046, without creating perverse incentives.

ORA recommends that PG&E retain six of the seven guarantees that are already in place, and add two new guarantees. The two additional guarantees would require PG&E to provide customers with at least three days notice of planned outages and to issue accurate bills to customers within 60 days of service initiation. ORA also recommends eliminating PG&E's service guarantee on responding within two hours to customer requests for emergency services. Because such emergencies generally

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[9] D.00-02-046, page 92.

[10] D.00-02-046, page 92.

[11] See especially letters from PG&E to Paul Clanon, dated January 3, 2002, and January 14, 2003 reporting results of PG&E Customer Service Guarantee Program; also, PG&E response to DR-ORA-326 question 1a.

threaten health or safety, PG&E has a sufficient incentive to respond immediately to reported emergencies, and the current guarantee on this subject is probably unnecessary. The eight guarantees ORA proposes for PG&E are explained in more detail below.

B. Proposed Service Guarantees

ORA proposes the following, slightly modified program of service guarantees. As was the case when PG&E's original Quality Assurance Program was adopted, any exceptions to new or modified guarantees, or assumptions needed for their application, should be defined along with reporting requirements by PG&E in consultation with ORA and other interested parties.

Service Guarantee 1: Missed Appointments

PG&E should continue to guarantee that it will keep scheduled appointments, and should increase the associated credit from $25 to $50 in instances when it fails to meet this guarantee. The increase is appropriate for several reasons. PG&E schedules customer appointments for 4-hour time windows, so each time PG&E schedules an appointment, the affected customer must plan to be available for at least half a day. Exemptions under the terms of this guarantee include same-day appointments and events in which PG&E misses an appointment due to a situation beyond its control or because the customer failed to provide needed access. If an excluded situation applies, PG&E may still cancel or miss an appointment without paying a credit, in some situations on short or no notice. A customer only receives a credit to compensate for lost time from work or other obligations if PG&E failed to meet the commitment under normal (non-emergency)

circumstances. A $50 credit is reasonable to compensate customers for the minimum of 4 hours of time lost waiting for PG&E to meet its commitment.

Based on the reduction in claims paid under this guarantee from 1,606 in 2001 to 1,011 in 2002[12], it does not appear that this guarantee is creating perverse incentives for customers. This concern over possible perverse incentives was cited by the Commission in adopting lower credit amounts in the last GRC. The reduction in claims may indicate that the credit is providing the hoped-for incentive for high quality service.

Service Guarantee 2: Non-Emergency Service Investigations

PG&E should continue to guarantee that it will investigate non-emergency situations, such as requests to check meters and investigate other customer concerns that do not require the customer to be present, within seven days of a customer request. In D.00-02-046, the Commission specified that "these investigations can be scheduled to fit the field service representative's schedule for the coming week,"[13] but this timeframe is not currently listed in descriptions of the guarantee. ORA recommends that the Commission, in reaffirming this guarantee, clarify that PG&E must investigate within a time frame acceptable to the company and the customer, not to exceed seven days. Requests that require the customer to be present would continue to be covered under Service Guarantee 1 because an appointment would be needed.

An increase in the credit amount from $25 to $50 is justified to compensate the customer for the additional time spent waiting for a resolution to their investigation when PG&E fails to meet this timeframe.

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[12] Letter from PG&E to Paul Clanon, dated January 3, 2002, reporting on 2001 Service Guarantee results, and PG&E response to DR-ORA-326 question 1a, attachment 2, revised report on 2002 results.

[13] D. 00-02-046 page 90

This increase is supported by the reduction in claims between 2001 and 2002 (from 47 to 20), with all reported claims made in 2002 resulting in payments to customers.[14] While two years of data are inadequate to establish a clear trend, the results indicate that the guarantee does not encourage customers to initiate investigations or file frivolous claims in the hope of receiving a credit.

Former Service Guarantee 3: Emergency Response

PG&E is currently required to respond immediately, usually within two hours, to requests for emergency service. Because such emergencies generally threaten health or safety, PG&E has other incentives to respond immediately to reported emergencies, and a guarantee on emergency situations should not be necessary. Therefore, ORA recommends that this guarantee be discontinued.

Service Guarantee 3 (formerly 4): Complaint Resolution

PG&E should be required to decide on a course of action to resolve each customer complaint and communicate it to the customer within three working days, and should fully resolve the complaint and communicate the resolution to the customer within ten working days. However, if final resolution of the complaint requires a field visit such as an off-site meter test or an on-site home audit, then the time allowed for resolution should be thirty days. PG&E's current guarantee allows only 5 days for complaint resolution; the additional time under this modified guarantee is reasonable because some types of complaints may take more than five days to resolve adequately. It retains the three-day limit to communicate the intended action

[14] Letters from PG&E to Paul Clanon, dated January 3, 2002, and January 14, 2003 reporting results of PG&E Customer Service Guarantee Program; also, PG&E response to DR-ORA-326 question 1a attachment 2, revised report on 2002 results.

and time until resolution to the customer, to ensure that customers receive prompt and adequate information on the status of their complaints.

PG&E paid only 60 claims under this guarantee in 2001, increasing to 472 claims in 2002, and provides no specific explanation for this change.[15] The increase ORA recommends in the time PG&E has to resolve complaints should be accompanied by an increase in the credit amount from $25 to $50. The higher credit is appropriate given the additional time PG&E has to respond, and it is also appropriate in that it will maintain consistency among the amounts of credits offered under this program.

Service Guarantee 4 (formerly 5): New Installations

PG&E should continue to guarantee that it will meet the agreed date for installing new meters and turning on service for customers. ORA proposes no changes to this guarantee, which requires PG&E to credit customers with $50 when it fails to initiate service on time.

Service Guarantee 5 (formerly 6): Response to Service Disruptions

PG&E should continue to guarantee that it will respond to service interruptions within 4 hours after receiving a customer report by either restoring service or informing the customer of when they can expect service to be restored. The only change ORA recommends to this guarantee is that the Commission should raise the credit for failure to meet this guarantee from $25 to $50.

The terms of this guarantee already exclude most widespread emergencies, and PG&E can avoid paying claims in this category simply by providing customers with timely and accurate information on when their

[15] Letters from PG&E to Paul Clanon, dated January 3, 2002, and January 14, 2003, reporting results of PG&E Customer Service Guarantee Program; also, PG&E response to DR-ORA-326 question 1a attachment 2, revised report on 2002 results.

power will be restored. While it is not yet clear whether this guarantee is providing an incentive for PG&E to improve its service, service interruptions cause inconvenience and disruption that may range from the costs of spoiled food to negative health impacts on customers who require life support equipment. Given this, a $50 credit is reasonable compensation for customers who not only lose power, but are not provided with accurate information within a reasonable time about when power will be restored.[16] The increased credit is also desirable to maintain consistency among the amounts of credits offered under this program.

Service Guarantee 6 (formerly 7): Restoring Service

PG&E should maintain its existing guarantee to restore service within 24 hours of a service disruption. The only change ORA recommends is that the Commission raise the credit for failure to meet this guarantee from $25 to $50 for each 24 hours without service.

As in the case of the guarantee of a four-hour response, the terms of this guarantee already exclude most widespread emergencies and many circumstances beyond PG&E's control. In general, when a customer experiences an electrical outage outside of a widespread emergency, they should expect the outage not to exceed 24 hours. A credit of $50 per day is reasonable compensation for the inconvenience and disruption experienced by customers faced with long outages.

[16] PG&E UO Guideline G12003 (provided in workpapers to PG&E–2 Chapter 8, page 8-30) includes PG&E's own value of service estimates for use in its capital investment decision process. ORA's testimony in this chapter does not take a position on the merit of PG&E's estimates of the value of service, but the amount listed per customer-minute implies that four customer-hours without electrical service is worth approximately $42.48.

Service Guarantee 7: Advance Notice of Planned Interruptions

PG&E should be required to provide customers with notice at least three days in advance of planned service interruptions, such as for equipment maintenance or upgrades. PG&E already provides notice to their customers seven days in advance for most planned electric outages not related to emergencies, and three days in advance in some "residential short notice" situations.[17] PG&E's existing policy recognizes that residential customers depend on power for basic needs such as refrigeration and climate control, as well as for home offices and other purposes, and some customers may require electricity to sustain life-support equipment. Customers who receive advance notice may be able to make arrangements to minimize the disruption caused by planned outages. PG&E should continue to provide as much notice as possible, at least maintaining current practices. Three days is consistent with the minimum notice given in non-emergency circumstances in PG&E's current internal standard (D-S0418),[18] and provides an amount of notice that may allow people to minimize the disruption caused by an outage in most cases. Less time could be insufficient in many situations. For example, a customer may not be present to receive notice on a daily basis; this may be the case if the customer is away on vacation or traveling for work. If a customer does not receive at least three days notice of a planned interruption, PG&E should provide the customer with a $50 credit consistent with the credits provided under the other guarantees.

Service Guarantee 8: Issuing First Bill

PG&E should be required to issue an accurate bill to every customer within 60 days of establishing service on a new customer account. When

[17] Response to DR-ORA 295, question 4.

moving into a new residence, a customer may not be aware of the amount of energy used by new or existing appliances. A timely first bill will assist customers in judging and managing their energy usage. For some customers, it may create a hardship to be billed for several months of usage at once. It is ORA's understanding that PG&E in the past had an internal standard to issue first bills to all new customers within 45 days of service initiation. PG&E currently has no specific policy on the time before the issuance of a customer's first (commencing) bill.[19] This proposed guarantee would provide PG&E with additional time, while still guaranteeing that PG&E customers get their first bill on a new account in a timely manner to avoid any inconvenience, such as unanticipated large bills. If a customer does not receive a PG&E bill within 60 days of establishing service, PG&E should provide the customer with a $50 credit, consistent with the credits provided under the other guarantees.

C. Reporting Requirements

Decision 00-02-046 requires "PG&E to report monthly on compliance and penalties to the Energy Division."[20] PG&E complies with this requirement by submitting monthly tables reporting the number of claims made, claims paid, and amounts of money paid, to facilitate tracking of their performance on these guaranteed standards and allow an evaluation of their performance under these guarantees. ORA recommends that PG&E continue to provide monthly information, but in quarterly (as opposed to

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[18] Response to DR-ORA 295, question 4.
[19] Response to DR-ORA 295, question 2.
[20] D.00-02-046, page 93.

monthly) reports to the Commission. The reduced frequency of the reports will allow PG&E to provide the same information with less duplication.

In addition to the existing tables, these quarterly reports should provide tables for each PG&E geographic division.[21] PG&E's tables, which aggregate the claims for all of their service territory, do not show whether certain types of claims are concentrated in particular locations; breaking this information down by PG&E division could reveal whether some locations within PG&E's service territory receive more consistent or reliable service than others.

These reports should also include text explaining any factors that lead to significant variations in the number of claims over time and by location. PG&E's reports do not provide explanations of such fluctuations, and this makes it difficult to determine whether changes in the claims made over time are due to changes in customer service or are due to unrelated circumstances. For example, in 2001, the number of claims made per month under guarantee 1, that PG&E will meet scheduled appointment times, ranges from 73 to 253, with 73 claims made in August, 78 in May, 229 in December, and 253 in January.[22] The high number of claims in the first and last months of the year does not seem to show any improvement in this category over the course of the year, but it is not clear what caused the differences, and existing reports do not explain the reasons for these variations. They could be due to some particular factor such as weather (with more claims made in winter months) or changes in PG&E staffing levels, or could just reflect

[21] PG&E's divisions are described in PG&E-13 chapter 2.

[22] Letter from PG&E to Paul Clanon, dated January 3, 2002, reporting results of 2001 PG&E Customer Service Guarantee Program.

random fluctuations.[23] To clarify the meaning of such fluctuations in the future, PG&E should be required to provide an explanation of material increases or decreases in claims made in consecutive months or in the same month in consecutive years. ORA recommends the explanations be required for variances exceeding +/- 25 percent.

PG&E should work with ORA and other interested parties to develop auditable tracking and reporting requirements for the service guarantee program to ensure that the reports contain the information necessary to evaluate PG&E's performance in the areas covered by these service guarantees.

V. CONCLUSIONS

ORA recommends that the Commission maintain a slightly modified service guarantee program for PG&E, based on its existing Quality Assurance Program. This proposal is not meant to be punitive. Rather, it is intended to provide an incentive for PG&E to maintain high-quality customer service. PG&E should report on this program to ORA, Energy Division, and other interested parties each quarter, and the reports should continue to include the monthly tables currently provided. In addition, future reports should provide similar tables on claims within each of PG&E's geographic divisions. These monthly reports should also explain any material fluctuations in the number of claims over time and in different locations. PG&E should work with ORA and other interested parties to define any specific assumptions for the application of new or modified guarantees or exceptions to those guarantees, as well as to develop auditable tracking and reporting procedures to ensure that the program is applied consistently.

[23] Response to DR-ORA-326, question 2.

CHAPTER 9-C

CALL CENTERS

I. INTRODUCTION

This section will present ORA's analysis of Pacific Gas and Electric Company's (PG&E's) Call Center operations. PG&E's Call Centers fall under its Customer Inquiry Assistance and Network Facilities and Equipment major work categories.[1] PG&E operates three call centers that are located in San Jose, Fresno and Sacramento. An additional facility in Stockton operates as a supplemental call center. After describing PG&E's call center related processes and procedures this testimony will present suggestions for areas where PG&E may devote more attention to alternatives from its current call center procedures.

II. SUMMARY/RECOMMENDATIONS

PG&E should explore new approaches of addressing ways to increase the length of time Customer Service Representatives (CSRs) employees stay in their positions. A balance of more experienced and less experienced CSRs are more likely to address customer service needs. More experienced CSRs will enable PG&E to have a CSR staff that can draw on historical experience in responding to customer's inquiries. Technology improvements and/or process changes in PG&E's field service staff may enhance communication between the CSRs and the field service representatives. Improved communication between the field and CSRs increases the likelihood that CSRs will have more timely and accurate information to respond to customer inquiries. PG&E should consider surveying its customers to determine whether the current AT&T translation service is responsive to the needs of non-English speaking ratepayers. The survey results from this inquiry can be

[1] Exhibit PG&E-3, PG&E 2003 Test Year Testimony, "Customer Services Costs," at p. 2-4.

used to determine whether employing non-English and non-Spanish bilingual CSRs would improve customer service to certain communities in PG&E's service territory.

III. DISCUSSION

PG&E has three call centers, which are located in Sacramento, San Jose and Fresno. There are a total of approximately 600 customer service representatives (CSR's) working in these call centers.[2] Approximately 40-45% are part time employees.[3] There are about 50 senior CSR's who supervise around 15 to 25 CSR's each, 13 senior CSRs are located in Sacramento.[4] The CSRs and senior CSRs are union employees. The next rungs of management above the senior CSRs are the team leaders, who are non- union, then the operations supervisor(s) and the overall call center manager. One of the most important components to the functioning of PG&E call center operations is the CSR.

A CSR receives 4 weeks of job training followed by 2 weeks of mentoring and ongoing training. Periodic trainings are also held throughout the year. The Sacramento call center is open 24 hours. The CSR's handle all calls for residential and small commercial customers. Large commercial customers, such as Chevron, have their own assigned representatives. The Account Services department handles the large business accounts. The CSR's handle calls relating to starting and stopping service, payment arrangements, billing problems, pilot re-light requests etc. Whenever a CSR is unable to resolve a customer request the call is escalated to a senior CSR. Depending on the complexity of the request or compliant, help tickets are submitted to various other departments such as payment research or

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[2] PG&E-3, PG&E 2003 Test Year Testimony, "Customer Services Costs," at p. 2-4.

[3] Information relayed verbally during site visit to PG&E Sacramento call center October 15, 2002.

[4] Ibid.

customer correspondence. PG&E has streamlined its call center operations by using an automated Interactive Voice Response Unit (IVRU).

All customer service calls pass through PG&E's automated IVRU. The IVRU is deployed among PG&E's three call centers. The IVRU system offers customers the choice of having many routine questions answered by an automated scripted recording without having to talk to a CSR. Incoming calls that are not handled by the IVRU system are automatically routed to available CSRs at each call center. A call could land in any of the 3 call centers depending on the call volume. However, after the Fresno and San Jose call centers close down, all calls get routed to the Sacramento call center. A CSR uses a variety of tools to assist them in responding to customer inquiries.

Among the tools that CSR's use are several scripts, guides and general references (both online and on paper) to help them answer customer inquiries. These guides give the CSR appropriate questions to ask the customer regarding the request or inquiry. For example, if the customer request is about a service turn-on, the guide may remind the CSR to ask the customer whether or not there is a dog at the premises. If the site does have a dog, the service order will note this information so that the PG&E field service representative is aware of the situation before they arrive at the site. It also allows the field representative to coordinate with the customer to gain safe access to the site. A CSR passes on customer requests for repair or service to PG&E's field service staff.

CSR's take requests for service and/or repair and submit them to a field dispatch service operator. The field dispatch service operator distributes the service/repair request to the field servicemen who conduct the repairs. PG&E's CSRs have access to display screens available through the Customer Information System (CIS) that are used to provide information to customers about conditions like emergencies and outages. In addition, at each call center there are electronic tele-message boards mounted on the walls with running text of notable news, like

pending storm activity. The tele-message boards also display call center statistics like the current average wait time and the number of calls in queue to be answered. If the board displays are colored red then the call volume is high, yellow indicates a medium call volume and green means a normal to lower than normal call load. This system along with other procedures allows PG&E's call centers to handle normal call volumes and respond to emergencies.

PG&E's call center managers keep an emergency call list of CSR's who can be called in to work during emergencies and during times when the call volume unusually high. These part-time CSRs are used to manage overall CSR workload and to provide overtime-scheduling relief. PG&E has implemented workforce management tools that monitor the call arrival patterns and coordinates call patterns with CSR staffing for better efficiency. Monitoring call volumes also enables PG&E to schedule last minute trainings. More extensive planned trainings have to be scheduled out in advance. For example, during the CorDaptix training PG&E hired 100 additional CSR's to operate the call center during the training period. CorDaptix is a commercial software package that PG&E selected to meet market and regulatory demands for billing and customer service.[5] PG&E company wide implementation and training for CorDaptix was completed at the end of 2002. PG&E's CSR's also have access to a training lab where they can go for additional CorDaptix and other training, as needed, when the call volume is low. Managing call volume is one of the main functions of the Customer Traffic Control Center.

PG&E's Sacramento call center is the core call center facility and hosts the Customer Traffic Control Center. The Customer Traffic Control Center monitors, keeps track of, and generates reports about the call activity at all of PG&E's call centers. It can track various call center statistics like call volumes, average handle time, average seconds to answer, number of calls waiting and for how long, average

[5] Exhibit PG&E-5, "Information Technology Costs," at pg. 2-2.

call duration, longest call, longest call waiting, abandoned calls and average abandon call time. A CSR's availability (to answer calls) must be 90% or higher.[6] When the average time to answer exceeds a minute, an alert for an increase in staffing is triggered. All call center related statistical information is real time and is refreshed every 3 seconds. The traffic control center also receives information from the meteorological department. The center is always tuned in to the weather, and is aware of any planned outages, through the Outage Information System (OIS). Scheduled CSR trainings are also entered into the control center system since trainings affect the number of CSRs available to answer calls. The control center automatically passes on information to CSR's through the CIS. This allows the CSRs at each call center to be constantly updated about any new developments. The control center enables PG&E to serve all the customers on its service territory.

PG&E serves a diverse population of communities within its territory. A language support contract with AT&T allows PG&E to provide a three-way calling interpreter service for customers that speak Chinese, Vietnamese or other languages. This translation service is available at all three call centers. Spanish language calls are handled in PG&E's Fresno call center by a team of 25 – 50 CSRs. The CSRs at the Sacramento and San Jose call centers operate in English.

The San Jose call center houses space for 221 CSRs. However, due to turnover there are currently 205 active CSRs in San Jose.[7] PG&E's call center in San Jose has 14 Senior Service Representatives (SSR), 4 Utility Administrative Clerks, 11 Supervisors, 1 Operations Supervisor, 1 Support Center Team Leader, 2 Quality Assurance Representatives, 1 Field Service Liaison, and 2 Schedulers.

The primary interface with customers for PG&E are its call centers. Generally customers call in to have their requests and inquiries handled and CSRs

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[6] Information relayed verbally during site visit to PG&E Sacramento call center October 15, 2002.

[7] Information related verbally by Phil Balistrieri, manager of the PG&E San Jose call center at a February 11, 2003 site visit.

call customers to inform them about the status of service calls, repairs and emergency events like fires and storms.[8] When a CSR receives a call from a customer about an outage, the CSR contacts the Dispatch Operator who then sends out field service representatives to the customer site to investigate and restore service. In the case of an outage affecting more than one customer, an event alert is triggered after the second call from two different customers about the same problem. The Dispatch staff contacts the Switching Center(s). The Switching Center sends repair staff to check PG&E devices in the field and broadcasts the information to all the CSRs through the OIS. One of the many CSR screens in the CIS is a color-coded map of California divided into 18 districts or divisions. The color indicates the approximate number of customers affected by an outage event and gives the CSR information about where in PG&E's customer territory the outage is occurring.

The Diagram, labeled Diagram 9C-1 (at the end of this chapter), displays the flow of information between PG&E CSR staff, customers and field representatives.

PG&E provided the following description about the interaction between its Customer Information System (CIS), its Field Automation System (FAS), and its Outage Information System (OIS).

> "PG&E customer service representatives input field service orders via computer keyboard entry into the CIS (Customer Information System). These field orders are downloaded to PG&E's Field Automation System (FAS) or Outage Information System (OIS) based on the type of field order. For FAS items such as gas service work, operations personnel dispatch the field order to a field service employee via a wireless network to the mobile data terminal in the field employee's vehicle. The field employee completes the customer request and enters field order completion data into the mobile

[8] Please refer to labels 1 and 7 in Diagram 9C-1.

data terminal. The completed field order information is returned via the same wireless network back to FAS, which in turn uploads the completion data to the CIS. During this process, customer service representatives are able to view the status of the field order by way of a connection to the FAS, from Pending state to Dispatched, to Enroute, to Onsite and Completion. For outages, service response and restoration status information is provided from the field staff that is dispatched to investigate and make repair. This information is called or radioed in to operations personnel for entry in the OIS via keyboard. Once entered in OIS, this information is uploaded to the CIS and is accessible for customer service representatives."[9]

PG&E's CSRs are in continuous communication with management through meetings and the various technology systems like CIS and OIS. The manager of the San Jose call center, Phil Balistrieri, related the following about internal communication, "…there is a monthly staff meeting with Kim Lytton, Director of Call Center Operations; a weekly conference call with Kim Lytton on weeks when the monthly meeting is not scheduled; a daily 10:10AM call with staff to discuss new developments in San Jose; daily Operations calls at 8:15AM; 10:30AM; and 2:00PM (this is with the Operations management staff at all the call centers), training may also be discussed on this call."[10] In addition, the CSR schedulers at each call center communicate by conference call to handle and coordinate time-off for CSRs to recover from major events like a storms and to schedule training sessions, vacations, etc.

IV. ANALYSIS

Overall PG&E does an excellent job through its call centers in providing information to customers about their requests and inquiries. However, ORA has

[9] PG&E Data Response No: ORA_0323-01

[10] Notes from February 11, 2003 site visit to PG&E San Jose Call Center

identified several areas in PG&E call center operations that can be improved. One area is CSR training and retention. According to the manager of the San Jose call center, 80% of the CSRs working in San Jose have been employed 2yrs or less in their position. Moreover, less than 10% have been employed for 10yrs or more. Some of the reasons offered for the low retention rates in San Jose include long commute times for some CSRs and transferring to other jobs within PG&E. PG&E should explore new approaches to addressing ways to increase the length of time CSR employees stay in their positions in order to have a balance of more experienced and less experience customer service representatives (CSRs) to better address customer service needs.

Another area for improvement is the communication between the field representatives and the CSRs. At step 5, in the "Information Flow Diagram between PG&E staff and the FAS and OIS systems," (refer to Diagram 9-C-1) field staff radio information from the field site about the status of a repair or outage. The status is sent to another staff member at a different location who keys the information into the OIS system. The CIS system accesses OIS to provide the status information to the CSR. There may be timesavings associated with using technology to allow a field representative to provide repair and outage status information to the FAS and OIS systems directly. CSRs depend on information from the field in order to respond to customer. Timely and accurate transfer of information to CIS helps CSRs to answer customer inquiries quickly and efficiently. ORA recommends that PG&E explore utilizing existing technology to allow the most efficient communication pathway between PG&E field personnel, its OIS/FAS systems and its CSRs. Technology improvements and/or process changes in PG&E's field service staff will enhance communication between the CSRs and the field service representatives. Improved communication between the field and CSRs will allow them to better service customer needs.

Outside of Spanish, ORA is currently unaware of other bilingual CSR staff at PG&E's call centers. Given the diversity of PG&E's service territory there may be communities that would benefit from having in-language customer service representatives. PG&E should survey its customers to determine whether the current AT&T translation service is responsive to the needs of non-English speaking ratepayers and if additional bilingual CSRs may improve customer service. According to PG&E's Demographic Trend Report a 2000 Estimate of its service territory reveals the following ethnic breakdown: 77.6% white, 7.1% black, 1.1% American Indian/Eskimo, 14.2% Asian/Pacific Islander. Those persons from black, white and other races that identify as ethnically Hispanic represent 23.0%. The 2005 projection shows similar ethnic percentages 76.8% white, 7.2% black, 1.3% American Indian/Eskimo, 14.7% Asian/Pacific Islander. For 2005, those persons from black, white and other races that identify as ethnically Hispanic represent 23.7%.[11] Given this demographic breakdown it is reasonable that PG&E has both English and Spanish speaking CSRs since this mirrors the two dominant speaking groups in its service territory. However, the communities in the Asian/Pacific Islander category represent the next most dominant ethnic group. A recent PG&E report to the CPUC entitled "PG&E Call Center CPUC Report – 2003," identifies calls to the call centers from Chinese and Vietnamese speaking customers at .4% of the total calls received in January 2003 and .5% of the total calls received in February 2003.[12] Despite the low volume of calls received in Chinese and Vietnamese, given their position as the third most populous ethnic group in PG&E's service territory, ORA recommends that PG&E investigate whether their AT&T translation service is meeting the needs of the various Asian/Pacific Islander communities.

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[11] PG&E Data Response No: ORA_0300-03

[12] Pacific Gas and Electric Company Call Center Monthly Report, February 2003, dated March 6, 2003

V. CONCLUSIONS

ORA recommends that PG&E explore enhancing their retention efforts for customer service representatives; investigate whether to implement technology improvements and/or process changes to enhance communication between the CSRs and the field service representatives; and, survey its non-English and non-Spanish speaking customers to determine whether the current AT&T translation service is responsive to their needs.

CHAPTER 9-D

WEB SITE

I. INTRODUCTION

PG&E provided information about its web site, pge.com, and its functions for residential and business customers. In addition to describing its web site features, it also provided the results of benchmarking studies, customer satisfaction surveys and web usage data. This chapter presents ORA's findings and recommendations on pge.com's usefulness to its customers.

This chapter reviews PG&E's web site program and recommends that PG&E:

- Improve web site functionality for all customers, but especially for residential customers,
- Bring pge.com to a reasonable level of customer service and to meet increasing customer expectations in conducting business through the Internet[1].
- Develop productivity goals linked to its web transactions and track its success in meeting these goals.
- Determine why usage of pge.com is declining and implement changes to improve usage of the site.
- Print its web address on the front of its bill in larger, bolder type.
- File a report with the Commission and ORA annually, for the next three years. The report should include updates on improvements to pge.com functionality, especially for residential customers; provide results of customer satisfaction surveys on the web site

[1] GRC2003-PH_DR_ORA_0101-03D.

and report PG&E's progress in improving its current rating in the lowest quartile of utility web site functionality.

II. BACKGROUND

PG&E has acknowledged that it has limited residential customer transactions as compared to those of other residential customer service channels (i.e. call centers and local offices.)[2] Customer opinion of pge.com's usefulness has been declining from the third quarter 2001 to second quarter 2002, and functionality on pge.com is limited and continues to fall behind rising customer expectations. Pge.com is ranked in the lowest quartile of utility web site functionality[3]. The table below summarizes the functionality of pge.com as compared to Southern California Edison.

Table 9-D-1: Web functionality comparison between PG&E and SCE

Functionality	PG&E	SCE
Pay Bill On-line*	Yes	Yes
Single-session Multiple Account Management	No	Yes
Make Payment Plan online	No-email; form only	Yes
View Current Account Balance*		
View Blue bill online	No	Yes
E-Mail Blue bill option	No	Yes
Online Direct Payment (electronic acct. debit)	No	Yes
Turn On service	No	Yes
Same Day Turn On	No	No
Turn Off service *	No	Yes
Transfer Service*	No	Yes

[2] GRC2003-PH_DR_ORA_0227-07.
[3] GRC2003-PH_DR_ORA_0101-03D.

Schedule Service Call*	No	Yes
Billing History	No	Yes
Personalization	No	Yes
Usage History	No	Yes
Update Account Information	No	Yes
Report a Street Light Outage	Yes	Yes
Request a Duplicate Bill	No	Yes
Request Tree Trimming	Yes	Yes
Residential Pricing Plan Calculator	No	No
Business Pricing Plan Calculator	No	No
Asian Portal	No	Yes
Spanish Portal	No	Yes

*Function currently performed by Customer Service on-Line (CSOL)

In 2000 and 2003, PG&E launched Customer Service On-Line (CSOL). CSOL offers customers online transactions, but provides residential customers only three transactions.[4]

- View current account balance,
- Pay bill
- Make a payment plan.

PG&E offers business customers those services plus:

- View Usage History (Business Customers only)
- Perform Rate Analysis (Business Customers only)
- Display Outage Information (Business Customers only)
- Inter-Act provides business customers with a platform for receiving notification of load curtailment events via e-mail and e-page.

[4] GRC2003-PH-1_DR_ORA_0227-05.

III. DISCUSSION

A. PG&E SHOULD IMPROVE ITS WEB SITE FUNCTIONALITY

Based on residential and small-business customer opinion surveys conducted by PG&E and JD Power & Associates, customers are very interested in using the Internet for conducting business.[5] Specifically, these surveys indicated customers are:

- Less interested in just viewing information on a web site.
- Increasingly interested in conducting transactions on the Internet.
- Increasingly interested in accessing their account/billing information in a secure environment.
- Interested in paying their bill online, if presented with adequate options and ease-of-use.

PG&E has added transactions based on customer requests, however, except for CSOL, functions added in response to customer surveys and requests have been for business customers:.

- Usage history lookup for business customers
- Rate analysis lookup for business customers
- Outage information for business customers
- Basic account aggregation so business customer can view all their accounts from a single log in.

PG&E 's 2003 Internet Service Department Forecast includes initiatives to provide additional online functions for residential customers. ORA urges PG&E to proceed with these residential functions as expeditiously as possible so that residential customers may benefit from web services as much as business

[5] GRC2003-PH_DR_ORA_0101-03D

customers do. PG&E should strive to attain as high a level of functionality for customers as Southern California Edison provides. In addition ORA recommends that PG&E develop productivity goals linked to its web transactions and track their success in meeting these goals.

PG&E's rank in the lowest quartile of web functionality is indicative of its poor customer service via the web. PG&E should be required to update ORA and the Commission annually on its progress in improving customer service via its web site.

B. PG&E SHOULD ENCOURAGE CUSTOMERS TO USE WEB SITE

PG&E measures the usefulness of pge.com by tracking hits, visits and page views on a weekly basis.[6] Based on this tracking, the usefulness of pge.com to customers has declined between 2001 and 2002 in two out of the three categories tracked.

Table 9-D-2: PG&E's 2001 and 2002 Web Tracking Results

ITEM	2001 Total	2002 (YTD thru week of 12/27/02)	% Change from 2000 to 2002
Hits	274,093,435	230,858,655	- 15 %
Page Views	21,115,612	29,775,252	41 %
Visitors	4,584,056	4,294,102	- 6 %

In contrast, J.D. Power and Associates reports a gradual, but steady, upward trend in residential customers that visit their utilities' web sites. [7]

Table 9-D-3:Residential Customer Use of Utility Web sites

Percent have visited electric	1999	2000	2001	2002

[6] GRC2003-PH-1_DR_ORA_0227-03.

[7] GRC2003-PH-1_DR_ORA_0050-06-2.

Utility's web site at least once	8%	7%	9%	10%

PG&E's decline in web usage is especially inexplicable and troubling when contrasted with increases in phone requests for information and assistance. PG&E reported a 28% increase in call volume to its call center in 2001. The largest increase in its forecasted 2003 expenses in MWC DK is attributable to the increase in the cost of labor.[8] The third largest contributor to that increase is an expected increase in call volume growth over 2000 levels, due to customer growth and the expanding nature of customer information needs. In 2000, PG&E's Correspondence Management group fulfilled 1.6 million requests for literature, an increase of 680% over 1996.[9] In contrast, in the fourth quarter of 2002, customers downloaded only 16,705 brochures from PG&E's 63 most popular files.[10]

This chapter is reviewing customer service issues, not cost comparisons between various means of delivering customer service. PG&E has not commenced a formal study to determine if the web is a more cost-effective method of service delivery than other alternatives. However, PG&E noted that industry studies suggest that cost saving opportunities exist if a significant volume of transactions can be migrated to the Web.[11]

ORA is not able to determine from information provided why web usage for pge.com is not increasing at the same rate as reported by J.D.Power and Associates. ORA is interested to see if improvements in functionality proposed in PG&E's 2003 Internet Service Department Forecast will affect its web usage

[8] GRC2003 (PG&E-3) 2-12.
[9] GRC2003 (PG&E-3) 2-10.
[10]. GRC2003-PH_DR_ORA_0227-04.

[11] GRC2003-PH_DR_ORA_0227-08.

figures. ORA wants PG&E to continue to track customer satisfaction with its web site functions and report the results to the Commission and ORA.

Finally, regarding web usage, ORA did not gather data or analyze PG&E's efforts to publicize its web site and functions, and thus cannot comment on the role those efforts play in PG&E apparently static web use figures. PG&E did not provide information on efforts to promote their web site except for mentioning that its July 2000 bill insert notified customers of the web site address for the Quality Assurance Program and customer service reps referred callers to the web site. ORA did note, however, that while the web address is on PG&E's bill, it is the last listing on the back of the bill, in small, faint type. PG&E's bill seems an obvious, inexpensive way to promote its web site to all its customers each month. When its new functionality is online ORA hopes PG&E will be bolder about providing the web address to its customers. ORA recommends that PG&E move its web address to the front of its bill and print it in a larger,bolder type face and explore other avenues to make customers aware of its web site and the functions available on the site.

IV. CONCLUSIONS AND RECOMMENDATIONS

In conclusion ORA recommends the Commission order PG&E to implement the following concerning its web site program.

- Improve its functionality, especially for residential customers,
- Bring pge.com to a reasonable level of customer service and to meet increasing customer expectations in conducting business through the Internet.[12]
- Develop productivity goals linked to its web transactions and track their success in meeting these goals.

[12] GRC2003-PH_DR_ORA_0101-03D.

- Determine why usage of pge.com is declining and implement changes to improve usage of the site.
- Print its web address on the front of its bill in larger, bolder type.
- File a report with the Commission and ORA annually, for the next three years. The report should include updates on improvements to pge.com functionality, especially for residential customers; provide results of customer satisfaction surveys on its web site and report its progress in improving its current rating in the lowest quartile of web site functionality.

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CHAPTER 10-A
ADMINISTRATIVE AND GENERAL EXPENSES
INTRODUCTION/SUMMARY

I. INTRODUCTION

ORA presents its estimates and recommendations on Administrative and General (A&G) expenses in this chapter. A&G expenses are general expenses not chargeable to a specific functional activity covered by the other chapters contained in this report. A&G expenses are recorded in FERC Accounts 920 to 935. PG&E has requested a total of $579.4 million for test year 2003 A&G expenses for its electric distribution, gas distribution, and electric generation operations. PG&E's request for A&G expenses for electric and gas distribution operations is presented in Exhibit PG&E-6, Chapter 6. PG&E's request for A&G expenses for electric generation operations is presented in Exhibit PG&E-10, Chapter 8. Discussion of PG&E's A&G activities, programs, and costs are presented in Exhibit PG&E-4, Chapters 2 through 7.

This chapter is comprised of sections A through G. The topic of each chapter and the sponsoring ORA witness are listed below:

Chapter	Topic	ORA Witness
A	Introduction/Summary	L. J. Woods
B	A&G Expense Allocations	G. Harpster
C	A&G Salaries and Expenses	G. Harpster
D	Outside Services	G. Harpster
E	Employee Pensions and Benefits	L. J. Woods
F	Insurance and Injuries and Damages	P. S. Phillips
G	Other A&G Expenses	P. S. Phillips

In Section II of this chapter, ORA summarizes the differences between ORA's and PG&E's forecasts for test year 2003.

II. SUMMARY AND RECOMMENDATIONS

ORA recommends a test year 2003 expense for A&G of $383.9 million. PG&E's forecast of $579.4 million exceeds ORA's forecast by $195.5 million or 51%. In Table 10-A-1, ORA presents its estimates of test year 2003 A&G expenses by account, allocated to electric distribution, gas distribution, and electric generation. Following that, Table 10-A-2 contains PG&E's estimates.

Table 10-A-1

ORA'S ESTIMATES OF

ADMINISTRATIVE AND GENERAL EXPENSES

(Thousands of 2000 dollars)

FERC Account	Description	Total Company	Total Utility[1]	Electric Distribution	Gas Distribution	Electric Generation
	Operations					
920	A&G Salaries	$119,161	$112,191	$46,527	$25,298	$20,424
921	Off. Supplies/Expenses	18,696	17,318	7,172	3,905	3,261
922	A&G Cap. Transfer	(18,795)	(18,795)	(7,629)	(4,372)	(3,795)
923	Outside Services	133,063	63,062	25,086	14,646	13,106
924	Property Insurance	10,709	10,709	7,199	2,721	(1,868)
925	Injuries & Damages	81,951	65,831	26,380	15,117	13,882
926	Pensions & Benefits	287,282	193,919	78,712	45,106	39,152
928	Reg. Comm. Exp.	0	0	0	0	0
930	Misc. Gen. Exp.	86,910	86,910	2,404	1,378	3,819
	Total Operations	$718,977	$531,145	$185,851	$103,7991	$87,981
	Maintenance					
935	Maint. Of Gen. Plant	$6,679	$6,679	$3,294	$2,434	$531
	Total Maintenance	$6,679	$6,679	$3,294	$2,434	$531
	Total A&G Expenses	$725,656	$537,824	$189,145	$106,233	$88,512

[1] Excludes Capital, O&M, Holding Company, Below the Line and Affiliates cost pools.

Table 10-A-2

PG&E ESTIMATES OF

ADMINISTRATIVE AND GENERAL EXPENSES

(Thousands of 2000 dollars)

FERC Account	Description	Total Company[2]	Total Utility[3]	Electric Distribution[4]	Gas Distribution[5]	Electric Generation[6]
	Operations					
920	A&G Salaries	$144,222	$141,825	$59,447	$32,338	$26,567
921	Off. Supplies/Expenses	24,175	23,307	9,684	5,428	4,316
922	A&G Cap. Transfer	(9,836)	(9,836)	(4,040)	(2,325)	(2,039)
923	Outside Services	168,157	124,818	46,522	27,374	21,943
924	Property Insurance	15,351	15,351	9,631	3,641	(1,524)
925	Injuries & Damages	94,500	79,252	32,211	18,534	17,012
926	Pensions & Benefits	430,013	296,229	121,688	70,020	61,395
928	Reg. Comm. Exp.	(0)	(0)	(0)	(0)	(0)
930	Misc. Gen. Exp.	91,285	91,285	4,230	2,434	4,758
	Total Operations	$957,867	$762,231	$279,373	$157,444	$132,428
	Maintenance					
935	Maint. Of Gen. Plant	11,233	11,233	5,178	3,520	1,489
	Total Maintenance	$11,233	$11,233	$5,178	$3,520	$1,489
	Total A&G Expenses	$969,100	$773,464	$284,551	$160,964	$133,917

III. CONCLUSIONS

ORA recommends that the Commission adopt its estimate of test year 2003 A&G expenses of $383.9 million. PG&E's estimate of A&G expenses for test year 2003 of $579.4 million exceeds ORA's forecast by $195.5 million or 51%. The

[2] Exhibit PG&E-6, Table 6-4. Data presented in thousands of 2000 dollars.

[3] Exhibit PG&E-6, Table 6-3. Excludes Capital, O&M, Holding Company, Below the Line and Affiliates cost pools. Data presented in thousands of 2000 dollars.

[4] Exhibit PG&E-6, Table 6-1. Data presented in thousands of 2000 dollars.

[5] Exhibit PG&E-6, Table 6-2. Data presented in thousands of 2000 dollars.

[6] Exhibit PG&E-10 (Revised 2/20/03), Table 8-4.

support for ORA's recommendations are contained in Chapters 10-B through 10-G of this report and in Overland Consulting's Administrative and General Expense and Allocations Report for Pacific Gas and Electric Company, General Rate Case, Test Year 2003.

CHAPTER 10-B

ADMINISTRATIVE AND GENERAL EXPENSE ALLOCATIONS

I. INTRODUCTION

This Chapter describes ORA's recommended allocations of Administrative and General (A&G) Expenses to regulatory categories. Regulatory categories include:

1. Construction (Capital)
2. Below-the-line
3. Affiliates (including holding company)
4. Unbundled Utility Service Functions

Costs attributable to construction are excluded from A&G expense because they are capitalized as part of the cost of new plant. Below-the-line costs are not recoverable from ratepayers pursuant to CPUC policy. Below-the-line costs include political advocacy costs, incremental costs attributable to PG&E's bankruptcy proceeding and the cost of public relations activities intended to enhance PG&E's general corporate reputation. The costs of providing services to affiliates are excluded from A&G expense because those costs are not necessary for providing utility service and do not benefit ratepayers.

The costs of PG&E's electric transmission, gas transmission and public purpose program functions are excluded from the GRC because they are recovered in other proceedings. Therefore, it is necessary to allocate, or unbundle, PG&E's A&G costs to utility service functions. PG&E refers to the utility service functions as Unbundled Cost Categories (UCCs). PG&E allocated its A&G costs to the following UCCs.

1. Electric Generation
2. Electric Transmission
3. Gas Transmission

4. Electric Public Purpose Programs
5. Gas Public Purpose Programs
6. Electric Distribution
7. Gas Distribution

PG&E's allocations for Accounts 920 through 923 reflect the results of its A&G Study. PG&E's allocations for Accounts 924 through 935 generally reflect the use of broad-based allocation factors.

PG&E's A&G study is a department-by-department review of PG&E's Corporate Services organization and the holding company. The A&G Study includes a total of 42 utility departments and 28 holding company departments. PG&E's A&G Study develops a total "gross" cost forecast for each department and allocates those costs to regulatory categories. The departmental allocations were prepared by each department.

ORA's review of PG&E's A&G Study and other A&G Account allocations was performed by a contractor, Overland Consulting. PG&E's A&G Study and other A&G account allocations are described in more detail in Overland's Administrative & General Expense and Allocations Report (the Overland Report). That report was submitted in this proceeding as an attachment to the testimony of ORA witness Harpster.

II. SUMMARY/RECOMMENDATIONS

ORA's recommendations concerning A&G allocation policy are summarized below.

1. ORA accepted PG&E's basic approach of using a department specific A&G Study to allocate A&G labor, materials and contract costs.

2. Allocations of costs to construction activities should reflect the incremental cost approach adopted in PG&E's 1999 GRC Decision. PG&E's capital allocations are inconsistent with that policy and significantly overstate A&G expense.

3. Allocations of holding company costs to the utility should reflect the holding company cost policies adopted in PG&E's 1999 GRC Decision. PG&E's holding company cost allocations significantly overstate A&G expense.

4. Incremental costs attributable to PG&E's bankruptcy proceeding and Plan of Reorganization (POR) should be assigned to the below-the-line category. PG&E failed to allocate all of the incremental costs attributable to its bankruptcy proceeding and POR implementation activities to the below-the-line category.

5. Costs incurred to influence elections and the decisions of elected government officials should assigned to the below-the-line category. PG&E failed to allocate all of those costs to the below-the-line category.

6. The cost of public relations activities designed to enhance PG&E's general corporate reputation should be assigned to the below-the-line category. PG&E failed to allocate all of those costs to the below-the-line category.

7. The Performance Incentive Plan (PIP) is PG&E's primary incentive pay plan. The allocation of PIP costs should reflect the CPUC's long-standing policy concerning incentive pay. That policy requires the allocation of 50% of the cost of the plan, at the targeted payout level, to shareholders. PG&E failed to allocate any of its PIP costs to below-the-line accounts.

8. ORA accepted PG&E's basic approach of allocating common A&G costs to UCCs based on non-A&G operations and maintenance labor (the M&O labor factor). However, the M&O labor factor used by PG&E is outdated and inconsistent with the factor it proposed in its January 2003 FERC electric transmission rate application. ORA's revised M&O labor factor allocates an additional 1.62 percent of A&G common costs to electric transmission.

9. PG&E failed to allocate any of its Account 925 third party claims and workers compensation bonds and fees costs to capital. ORA allocated 19 percent of the third party claims costs and 32 percent of the workers compensation bonds and fees to capital.

10. The labor factors PG&E used to allocate employee benefit costs and other workers compensation costs to the capital, affiliate and below-the-line regulatory categories are outdated and incorrectly calculated. ORA's recommended factors allocate an additional 1.87 percent to capital and an additional 0.27 percent to affiliates and below-the-line.

Chapter 2 of the Overland Report describes and explains the allocation standards used by ORA. Chapters 3 through 9 of the Overland Report apply those standards to PG&E's A&G departments and holding company departments. PIP allocations are discussed in Chapter 10 of the Overland Report. Allocations for A&G Accounts 924 through 935 are discussed in Chapter 11 of the Overland Report.

III. DISCUSSION/ANALYSIS

The CPUC adopted an incremental cost approach to allocating costs to construction activities in PG&E's 1999 GRC Decision. Under the incremental approach "the question to be answered is whether the cost would be incurred if construction were not undertaken."[1] Under the incremental approach "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."[2] ORA used the incremental cost approach adopted in the 1999 GRC decision.

The CPUC's long-standing policy is to exclude incremental costs attributable to the formation of a holding company from utility rates. The CPUC affirmed that policy in PG&E's 1999 GRC Decision.[3] PG&E's 1999 GRC decision states:

> ...PG&E Corporation was formed to allow shareholders to participate in non-regulated business opportunities. PG&E has not demonstrated that ratepayers

[1] D.00-02-046, page 287

[2] D.00-02-046, page 287

[3] D.00-02-046, page 277 quoting D.86-01-026.

> 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 the incremental costs resulting from the formation of PG&E Corporation that provide no demonstrable benefit to the utility to be allocated to the utility's affiliates.

The 1999 GRC decision disallows a significant portion of the costs of holding company executive management. The decision states "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."[4]

PG&E basically disregarded the CPUC's holding company policy in its 2003 forecasts. PG&E included almost all of the holding company costs that were disallowed in the 1999 GRC decision in its 2003 forecasts. ORA's forecasts reflect the holding company allocation policies affirmed and adopted in the 1999 GRC. Specifically, ORA included holding company charges in A&G expense only to the extent that the holding company is expected to provide actual identifiable services to PG&E and the service actually benefits PG&E.

PG&E's policy is to charge incremental costs attributable to its bankruptcy proceeding and POR to below-the-line accounts. PG&E's 2003 GRC does not assume any reorganization of PG&E's current structure and does not seek any funding increase based on the POR.[5] PG&E's bankruptcy and POR are the direct results of costs that are the responsibility of shareholders and not GRC related costs. Therefore, the incremental costs of PG&E's bankruptcy proceeding and POR implementation activities should not be charged to ratepayers through the GRC. ORA accepted PG&E's general approach of excluding incremental costs attributable to the bankruptcy proceeding and POR from 2003 GRC A&G forecasts.

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[4] D.00-02-046, page 277

[5] OC-36

The CPUC has a long-standing policy of excluding the costs of legislative advocacy from utility rates.[6] PG&E engages in a number of political activities, including opposition to municipalization ballot initiatives and support for selected political candidates. The cost of overtly political activities should be charged to below-the-line accounts consistent with CPUC policy.

PG&E also engages in public relations activities designed to enhance its general corporate reputation. PG&E's internal documents link its reputation enhancement activities to its political objectives under the theory that an enhanced reputation increases the likelihood of favorable governmental decisions. The CPUC has a long-standing policy of charging the cost of corporate image enhancement advertising to below-the-line accounts. The cost of public relations activities designed to enhance PG&E's general corporate reputation should also be charged to below-the-line accounts.

Chapter 2 of the Overland Report contains additional support for ORA's recommended cost allocation policies.

IV. CONCLUSIONS

PG&E basically disregarded the CPUC's policies concerning holding company costs and incentive pay in its 2003 forecasts. PG&E's allocations to capital are inadequate. PG&E failed to properly exclude incremental costs attributable to its bankruptcy proceeding and POR from its forecasts. ORA's allocations reflect long-standing CPUC policies and sound ratemaking principles. Accordingly, ORA's recommended A&G expense allocations should be adopted.

ORA's A&G expense allocations are explained further in Chapters 10-C and 10-B of this report and in the Overland Report.

[6] 62 Cal. 2d 634, 670 citing D.67369

CHAPTER 10-C

A&G SALARIES AND EXPENSES

I. INTRODUCTION

This Chapter presents ORA's recommendations for A&G Accounts 920 (Administrative and General Salaries), 921 (Office Supplies and Expenses) and 922 (Administrative Expenses Transferred - Credit).

Section II of this Chapter summarizes the differences between ORA's and PG&E's recommendations concerning the accounts. Section III presents ORA's analysis and support for ORA's forecasts and allocations for the accounts. Section IV provides ORA's conclusions.

ORA's forecasts and allocations were developed by a contractor, Overland Consulting. This Chapter provides a summary level discussion of ORA's recommendations. The detailed level support for ORA's recommendations is contained in Overland Consulting's Administrative & General Expense and Allocations Report (the Overland Report). That report was submitted in this proceeding as an attachment to the testimony of ORA witness Harpster.

II. SUMMARY/RECOMMENDATIONS

The following table compares ORA's and PG&E's 2003 test year recommendations for Accounts 920, 921 and 922 at a total company A&G expense level.

TABLE 10-C-1
ACCOUNTS 920, 921 and 922
(2000 Constant Dollars in Thousands)

Account	ORA	PGE	Difference	Percent
920	112,277	141,826	(29,549)	(20.83)
921	17,318	23,307	(5,989)	(25.70)
922	(18,795)	(9,837)	(8,958)	91.06
Total	110,800	155,296	(44,496)	(28.65)

III. DISCUSSION/ANALYSIS

Accounts 920, 921 and 922 are interrelated. Accounts 920 and 921 are both allocated to regulatory categories using department specific labor factors developed in the A&G study. Many of the forecast adjustments proposed by ORA affect both labor (Account 920) and materials (Account 921).

Account 922 reduces the gross balances reported in Accounts 920 and 921 to transfer construction related costs to plant. Accounts 920, 921 and 922 will be discussed in aggregate to avoid redundancy.

The differences between ORA's and PG&E's forecasts can be categorized as forecast adjustments and allocation differences. The following table shows the forecast differences by category.

TABLE 10-C-2
ACCOUNTS 920, 921 and 922
(Dollars In Thousands)

Description	Amount
PIP Incentive Pay	(24,701)
Forecast Adjustments	(9,673)
Allocation Differences	(11,471)
De-escalation	1,349
Total	(44,496)

PG&E's Performance Incentive Plan (PIP) is its primary incentive pay plan. The CPUC's policy is to forecast incentive pay at the targeted payout level and to allocate 50% of the forecast expense to shareholders. PG&E did not allocate any of its PIP forecast to shareholder funded below-the-line accounts. In addition, PG&E failed to correctly calculate the portion of the PIP costs allocable to construction. ORA reduced PG&E's 2003 forecast by $24.7 million to correct those errors. The PIP adjustments are developed and explained in Chapter 10 of the Overland Report.

The following table shows the forecast adjustments by department and type.

TABLE 10-C-3 ACCOUNTS 920, 921 and 922 - FORECAST ADJUSTMENTS (Dollars In Thousands)		
Department	Primary Basis	Amount
SAP Operations & Control	SAP SI	(486)
Budget	SAP SI	(478)
Payroll	Headcount/SAP SI	(166)
Corporate Accounting	Orders Materials	(205)
Risk Management	Headcount/Controls Project	(2,380)
Internal Communications	Headcount	(204)
Local Governmental Relations	Headcount/ COC Fees	(68)
Revenue Requirements	Headcount	(585)
External Relations	Headcount / Donations	(552)
HR Business Ops, Svcs & Systems	Headcount	(911)
SH&C Workers Compensation	Headcount	(503)
SH&C Third Party Claims	Headcount	(216)
SH&C Safety Engineering	Headcount	(390)
Non-A&G Study Departments	SAP SI and Other	(2,529)
Total		(9,673)

ORA's forecast adjustments are developed and explained in Chapters 3 through 7 of the Overland Report. The SAP System Integration (SAP SI) project was a non-recurring information systems project that was completed in June 2001. The SAP SI forecast adjustments eliminate the cost of the project from PG&E's 2003 forecasts. PG&E agrees that SAP SI costs should be eliminated from the budget department forecast. The other departments should receive the same treatment.

PG&E's forecasts for several utility departments reflect staffing levels that significantly exceed historical and current levels. The headcount adjustments reduce PG&E's forecasted labor costs and employee expenses to reflect reasonable expectations concerning staffing levels.

PG&E's Risk Management department performs an internal control function. PG&E's Account 921 forecast for its Risk Management department includes $3.2 million for the acquisition of new deal capture, credit analysis and price forecasting

systems. PG&E has not responded to ORA's requests for support for the forecasted cost of those systems. The Risk Management forecast adjustment difference includes the elimination of the cost of those systems.

The local governmental relations adjustment reflects an increase in staffing over the levels forecasted by PG&E and the elimination of $459,500 in local Chamber of Commerce fees.

PG&E's A&G Study was limited to departments within its Corporate Services organization. Some of the costs charged to Accounts 920 and 921 come from department's that were excluded from PG&E's A&G Study. PG&E refers to those charges as Non-Study Department (NSD) costs. NSD costs are charged to A&G when the NSD charges an order that translates to an A&G account. PG&E included $21 million of NSD costs in its combined Account 920 and 921 forecasts. ORA's NSD adjustments eliminate non-recurring SAP SI project costs and non-recurring accounting adjustments and accounting errors from PG&E's forecast. The NSD adjustments are discussed in Chapter 10 of the Overland Report.

The following table shows the allocation differences by department and type.

TABLE 10-C-3 ACCOUNTS 920, 921 and 922 - ALLOCATION DIFFERENCES (Dollars In Thousands)		
Department	Primary Basis	Amount
Business and Financial Planning	POR	(225)
Accounts Payable	Capital	(413)
Corporate Accounting	POR / Affiliate	(756)
Capital Accounting	Capital	(438)
Purchasing	Capital	(660)
SVP Public Affairs	Below-the-Line	(136)
VP Communications	POR	(340)
Internal Communications	Miscellaneous	46
Media Relations	Below-the-Line	(308)
VP Governmental Relations	Below-the-Line	(439)
Local Government Relations	Below-the-Line	(1,490)
External Relations	Below-the-Line	(272)
Industrial Relations	Capital	(261)
HR Benefits	Capital	(391)
HR Services	Capital	(1,780)
HR Compensation	Capital	(124)
HR Prof. Staffing & Diversity	Capital	(382)
Law	POR	(2,074)
SH&C Directors Office	Capital	(40)
SH&C Workers Compensation	Capital	(343)
SH&C Third Party Claims	Capital	(438)
Affiliate Rules & Regulatory Compl.	Affiliate	(207)
Total		(11,471)

ORA's recommended allocations are developed and explained in Chapters 3 through 7 of the Overland Report. PG&E failed to follow the capital allocation policies adopted in its 1999 GRC Decision. The capital allocation differences shown above reflect the incremental approach to attributing A&G costs to capital adopted in the 1999 GRC decision.

PG&E's bankruptcy proceeding and Plan of Reorganization (POR) are the direct consequence of costs that are the responsibility of shareholders. Therefore, the incremental costs of the bankruptcy proceeding and POR should be charged to below-

the-line shareholder funded accounts. The POR allocation differences shown above eliminate incremental bankruptcy and POR costs from PG&E's 2003 forecasts.

The cost of activities designed to influence political decisions should be charged to below-the-line accounts consistent with CPUC policy. Similarly, the cost of public relations activities designed to enhance PG&E's general corporate reputation should also be charged to below-the-line accounts. PG&E failed to allocate most of those costs to below-the-line accounts. The below-the-line allocation differences shown above remove the costs of political advocacy and general reputation enhancement activities from PG&E's 2003 forecasts.

IV. CONCLUSIONS

GRC test year cost forecasts for A&G departments should reflect realistic forecasts of staffing levels. PG&E's forecasted staffing levels are excessive compared to the current and historical levels in many of its A&G Departments.

PG&E's 2003 forecast allocations to the capital and below-the-line categories are inconsistent with CPUC policy and should be rejected. PG&E failed to allocate 50% of its PIP costs to below-the-line and significantly under-allocated PIP expense to capital.

ORA's recommended forecasts for Accounts 920, 921 and 922 are based on a detailed department-by-department review of costs and allocations. ORA's recommended forecasts are consistent with CPUC policies concerning incentive pay, capital allocations and below-the-line costs. ORA's forecasts are reasonable and should be adopted for the reasons stated in the Overland Report.

CHAPTER 10-D

OUTSIDE SERVICES

I. INTRODUCTION

This Chapter presents ORA's recommendations for A&G Account 923, Outside Services. The Outside Services account has two principle components. The contract costs incurred by PG&E's A&G departments and the charges to PG&E from its holding company, PG&E Corporation.

Section II of this Chapter summarizes the differences between ORA's and PG&E's recommendations concerning Account 923. Section III presents ORA's analysis and support for ORA's forecasts and allocations. Section IV provides ORA's conclusions.

ORA's Account 923 forecast and allocations were prepared by a contractor, Overland Consulting. This Chapter provides a summary level discussion of ORA's recommendations for Account 923. The detailed level support for ORA's recommendations are contained in Overland Consulting's Administrative and General Expense and Allocations Report (the Overland Report)

II. SUMMARY/RECOMMENDATIONS

The following table compares ORA's and PG&E's 2003 test year recommendations for Account 923 at a total company A&G expense level.

TABLE 10-D-1 ACCOUNT 923 OUTSIDE SERVICES (2000 Constant Dollars in Thousands)				
Account	ORA	PG&E	Difference	Percent
923	59,797	124,818	(65,021)	(52.09)

III. DISCUSSION/ANALYSIS

The differences between ORA and PG&E's forecasts can be divided into the following categories.

TABLE 10-C-2 ACCOUNT 923 OUTSIDE SERVICES (Dollars In Thousands)	
Description	Amount
HC - Labor and Materials Adjustments	(2,488)
HC - Labor and Materials Allocations	(19,049)
Holding Company Contracts	(10,620)
Holding Company Corporate Items	(10,430)
Utility Contracts	(23,370)
Utility Non-Study Department Adjustments	(2,862)
De-Escalation	3,798
Total	(65,021)

The holding company adjustments, allocations, contracts and corporate items amounts are developed and explained in Chapters 7 through 9 of the Overland Report. The utility contract adjustments and allocations are developed in Chapters 3 through 6 of the Overland Report. The utility non-A&G study department adjustments and de-escalation amounts are developed and explained in Chapter 10 of the Overland Report.

The following table shows the holding company differences by department.

TABLE 10-C-3 ACCOUNT 923 OUTSIDE SERVICES - HOLDING COMPANY DIFFERENCES (Dollars In Thousands)				
Department	Adjustments	Allocations	Contracts	Total
Chairman, CEO and President	0	(1,965)	(993)	(2,958)
SVP General Counsel	0	(727)	0	(727)
Law Department	0	(1,911)	(2,123)	(4,034)
Internal Audit	(731)	(929)	(124)	(1,784)
Legal Compliance & Business Ethics	0	(356)	(102)	(458)
Risk Initiatives	0	(105)	0	(105)
SVP Public Affairs	0	(135)	(139)	(274)
VP Federal Government & Reg. Relations	(170)	(754)	(662)	(1,586)
Regional Governmental Relations	0	(246)	(325)	(571)
SVP Human Resources	0	(3,129)	(1,479)	(4,608)
VP and Assistant to the Chairman	0	(269)	0	(269)
Corporate Secretary	0	(937)	(1,130)	(2,067)
VP Corporate Communications	(104)	(531)	(714)	(1,349)
SVP CFO	0	(637)	(2,153)	(2,790)
SVP Controller	0	(360)	(354)	(714)
Corporate Accounting	(197)	(2,639)	13	(2,823)
Tax	(653)	0	0	(653)
Financial Planning	(132)	(396)	0	(528)
Financial Analysis	0	(526)	0	(526)
Technical & Risk Management Accting	0	(226)	(27)	(253)
Investor Relations	0	(272)	(63)	(335)
VP Strategic Planning	160	(918)	(39)	(797)
Risk Management	0	(237)	0	(237)
VP & Treasurer	(320)	0	0	(320)
Banking & Money Management	0	(132)	0	(132)
Information Technology	(341)	(712)	(206)	(1,259)
Total	(2,488)	(19,049)	(10,620)	(32,157)

The Internal Audit and Tax Department forecast adjustments eliminate excessive staffing levels included in PG&E's 2003 forecast. The allocation differences reflect the CPUC holding company policies affirmed and adopted in the 1999 GRC decision.

The contract differences for the holding company CEO, Law, SVP Human Resources, SVP CFO and SVP Controller departments reflect both forecast adjustments and allocation differences. The remaining contract differences relate solely to allocation differences. The contract adjustments eliminate excessive and unsupported costs included in PG&E's 2003 forecasts. The allocation differences reflect the CPUC's holding company cost policies.

Holding company corporate items are costs that are not assigned to a department in PG&E Corporation's accounting system. PG&E included $16.2 million in its 2003 holding company forecast for corporate items. The corporate items consist largely of incentive pay and executive supplemental retirement plan costs. The CPUC's policy is to allocate 50% of the targeted amount of incentive pay to below-the-line shareholder funded accounts. PG&E did not allocate any of the holding company's incentive pay costs to the below-the-line category. The corporate items are primarily labor related. PG&E allocated 76.4% of the corporate items to PG&E using a broad based "multi-factor" allocation factor. ORA allocated approximately 35% of the holding company's labor costs to PG&E. The holding company corporate items difference reflects the CPUC's incentive pay policy and ORA's allocations of holding company labor costs to PG&E. The holding company corporate items are discussed in Chapter 9 of the Overland Report.

The following table shows the utility contract differences by department.

Table 10-C-2 Account 923 Outside Services Utility Contract Differences (Dollars In Thousands)	
Department	Total
SVP Treasurer and CFO	(4,153)
VP and Controller	(730)
Capital Accounting	(111)
Risk Management	(134)
SAP Operations and Control	(325)
Internal Communications	(275)
VP Governmental Relations	(103)
VP Communications	(91)
Media Relations	(36)
Revenue Requirements	(1,072)
External Relations	(24)
Law	(11,956)
SH&C Workers Compensation	185
SH&C Safety Engineering	(1,245)
Purchasing	(3,300)
Total	(23,370)

The SVP Treasurer & CFO contract difference eliminates unsupported contract costs included in PG&E's forecast and tax consulting contract costs duplicated in PG&E's forecast for the holding company Tax Department. The VP Controller contract difference eliminates excessive costs included in PG&E's forecast for its annual financial statement audit. The Revenue Requirements contract difference reduces PG&E's forecast of contract costs for GRC expert witnesses and case support to reflect a realistic forecast of 2003 costs. The Law Department difference eliminates outside legal fees and consultant costs for PG&E's chromium litigation. The Safety Health & Claims Safety Engineering Section contract difference eliminates costs included in PG&E's forecast for a speculative and unsupported ergonomics program. The Purchasing Department difference eliminates costs for speculative and unsupported e-commerce and automated purchasing information technology projects.

The support for the utility contract cost adjustments is contained in Chapters 3 through 6 of the Overland Report.

The utility non-A&G Study department differences reflect adjustments to eliminate the costs of a non-recurring SAP System Integration (SAP SI) project and adjustments to eliminate non-recurring accounting adjustments and accounting errors. Those adjustments are described in Chapter 10 of the Overland Report.

IV. CONCLUSIONS

PG&E's Account 923 forecast basically ignores the CPUC policies concerning holding company costs and includes inflated estimates of holding company and utility contract costs. ORA's forecast reflects a detailed department by department review of holding company costs and utility contract costs. ORA's forecast reflects CPUC policy and realistic expectations of 2003 contract costs. ORA's Account 923 forecast is reasonable and should be adopted for the reasons stated in the Overland Report.

CHAPTER 10-E
EMPLOYEE PENSIONS AND BENEFITS

I. INTRODUCTION

ORA presents its analysis and recommendations regarding PG&E's request for test year employee pension and benefits expense in this chapter. For purposes of this discussion, employee pension and benefits are defined as all employer-provided benefit plans and programs, comprising FERC Form 1 (electric operations) and FERC Form 2 (gas operations) Account 926. This includes pensions, postretirement benefits other than pensions (PBOPS), health care, dental care, vision care, group life insurance, long term disability (LTD), savings plans, tuition reimbursement, relocation reimbursement, flexible benefits and service awards.

In A.02-11-017, PG&E presented its pension and benefits expense on a total company basis. ORA reviewed PG&E's request on a total company basis. Overland Consulting's Administrative & General Expense and Allocations Report (the Overland Report) contains ORA's recommendations regarding the appropriate allocations to capital, operations and maintenance (O&M), holding company, and affiliates/below-the-line, as well as unbundling to unbundled cost categories (UCCs).[1] This approach allows for a uniform comparison of PG&E's request to ORA's recommendations for Account 926.

In Section II of this chapter, ORA summarizes the differences between ORA's and PG&E's recommendations. In Section III, ORA presents its analysis of PG&E's test year 2003 request for Account 926 and support for ORA's forecasts and adjustments. ORA's conclusions are in Section IV.

[1] PG&E's unbundled cost categories are identified in Ex. PG&E-6, Table 1-1.

II. SUMMARY AND RECOMMENDATIONS

ORA examined PG&E's request for test year 2003 expenses for Account 926 and conducted an independent analysis of PG&E's supporting workpapers. Through discovery, ORA obtained and reviewed additional documentation regarding PG&E's request. ORA also reviewed past Commission decisions regarding pensions and benefits as well as published articles discussing pensions and benefits. In addition, ORA reviewed relevant discovery responses provided to Overland Consulting and other parties to this proceeding. PG&E requests $426.7 million in pensions and benefits on a total company basis for the test year,[2] while the corresponding ORA estimate is $287.3 million. ORA's test year 2003 recommendations are less than PG&E's because: (1) ORA incorporated more currently available data; and (2) ORA's analyses result in forecasts that differ from PG&E's test year 2003 forecasts for retirement pension contribution. ORA recommends the following adjustments to PG&E's request, on a total company basis:

- Reduce PG&E's request by $128.6 million on a total company basis to reflect ORA's recommendation that the projected expense for PG&E's pension contribution for test year 2003 is not required in the test year.
- Reduce PG&E's request by $10.1 million on a total company basis to reflect ORA's application and use of 2002 recorded data in its analyses, calculations and recommendations and differences in allocations.
- Reduce PG&E's request by $0.8 million to remove the cost of service awards consistent with prior Commission decisions.

[2] Exhibit PG&E-4, Table 5-1.

Table 10-E-1 presents the differences between ORA's and PG&E's forecasts of test year 2003 expenses for Account 926 – Pensions and Benefits by program. All test year 2003 forecasts are presented in 2000 constant dollars unless otherwise stated.

Table 10-E-1

COMPARISON OF ORA'S AND PG&E'S
2003 TEST YEAR EXPENSE FORECASTS
FOR ACCOUNT 926 –PENSIONS AND BENEFITS

Total Company Basis
(Thousands of 2000 dollars)

Benefit	**ORA Forecast**	**PG&E Forecast[3]**	**Amount PG&E Exceeds ORA**	**Percentage PG&E Exceeds ORA**
Retirement[4]	$2,574	$131,206	$128,632	4997.36%
PBOPS Medical[5]	60,300	60,300	0	00.00%
PBOPS Life Ins.	4,182	4,182	0	00.00%
Savings Plan	33,705	33,705	0	00.00%
Medical	98,412	104,442	6,030	6.13%
Dental[6]	18,224	20,385	2,161	11.86%
Vision[7]	2,744	3,300	556	20.26%
LTD	61,900	61,900	0	00.00%
Group Life	2,297	2,297	0	00.00%
Relocation	2,366	3,144	778	32.88%
Tuition Refund	1,114	1,582	468	42.00%
Service Awards	0	837	837	---------
Flex Benefits[8]	(535)	(535)	0	00.00%
Total	$287,283	$426,745	$139,462	48.55%

[3] The Total Company amount is shown before capitalized and other allocation amounts are removed. Exhibit PG&E-4, Table 5-1.

[4] The estimates for test year 2003 are presented in 2003 nominal dollars. According to PG&E, it did not de-escalate this forecast because the process would be too complex and expensive. PG&E response to data request ORA-309, Q. 3.

[5] The estimates for test year 2003 are presented in 2003 nominal dollars. According to PG&E, it did not de-escalate this forecast because the process would be too complex and expensive. PG&E response to data request ORA-309, Q. 3.

[6] The estimates for test year 2003 are presented in 2003 nominal dollars. According to PG&E, it did not de-escalate this forecast because escalation was embedded in the forecast. PG&E's response to data request ORA-309, Q. 3.

[7] The estimates for test year 2003 are presented in 2003 nominal dollars. According to PG&E, it did not de-escalate this forecast because escalation was embedded in the forecast. PG&E's response to data request ORA-309, Q. 3.

[8] The estimates for test year 2003 are presented in 2003 nominal dollars. According to PG&E, it did not de-escalate this forecast because the plan was forecast to be a set dollar amount each year with no escalation. PG&E's response to data request ORA-309, Q. 3.

III. DISCUSSION/ANALYSIS

In this section, ORA addresses PG&E's test year 2003 request for Account 926 – Pensions and Benefits on a program basis.

A. Retirement Plan

PG&E forecasts $131.2 million for its test year 2003 retirement plan on a total company basis. The total is comprised of two components: $128.6 million for forecasted pension contribution in 2003 and $2.7 million for supplemental pension benefits that cannot be paid from the trust.

Financial Accounting Statement (FAS 87) prescribes the financial accounting and reporting for retirement plans. In D.88-03-072, the Commission did not adopt FAS 87 for ratemaking purposes. In D.89-12-057, the Commission adopted a methodology that allowed revenue requirements for pension costs based on the estimated contribution to the pension plan trust. PG&E uses the Entry Age normal actuarial cost method to determine the annual contribution to the Plan under ERISA. According to PG&E, the Employee Benefit Committee (EBC) is responsible for approving company contributions to the Retirement Plan Trust.[9] The EBC normally meets in the fall of each year to approve the annual contribution to the Trust.

PG&E forecasts a test year 2003 expense for its pension trust contribution in the amount of $128.6 million precipitated by the poor performance of the stock market over the last two to three years. PG&E's forecast is based on an analysis performed by its actuary, Towers Perrin, which was presented to the EBC in August 2002. The analysis suggests that a resumption of moderate contributions in the near term will reduce the <u>possibility</u> of very large required contributions in 2007.[10] (Emphasis added).

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[9] PG&E's response to data request ORA-135, Q.1.
[10] PG&E's response to data request ORA-135, Q. 3.

PG&E states that final decisions regarding the trust contribution will not be made until the fall of 2003.[11]

PG&E's pension contributions are constrained by IRS/ERISA minimum contribution and maximum tax-deductible contribution limits. To demonstrate the uncertainty of future predictions of pension contributions, ORA submits that PG&E declined to estimate these limits for years beyond 2003 stating that "[f]orecasting 2004 and 2005 limits will require Towers Perrin to make certain assumptions regarding interest rates, trust asset return, etc. that are too volatile and difficult to predict."[12]

PG&E's calculation of pension trust contributions using the Entry Age normal actuarial cost method has historically resulted in generating contribution amounts that exceed the tax-deductible limits imposed by the IRS.[13] For PG&E's pension trust the IRS/ERISA minimum and maximum limits have both been zero since 1998. Therefore, even though the use PG&E's actuarial cost method resulted in pension expense, PG&E has not been able to make tax-deductible contributions since 1997. ORA submits that PG&E's forecast test year contribution to its pension trust is not required to maintain the integrity of the fund in the test year.

While ORA is sensitive to the declining value of PG&E's pension fund investment, there is no threat to the integrity of the pension fund if PG&E does not make a contribution in the test year. According to Towers Perrin's analysis, even after the poor stock market performance through mid-2002, the chances of needed contributions to the pension fund are 50% by 2007 and 75% by 2009.[14] PG&E will have ample opportunity to present a

[11] PG&E's response to data request ORA-135, Q. 3.
[12] PG&E's response to data request ORA-145, Q 4.
[13] PG&E's response to data request ORA-145, Q 3.
[14] PG&E's response to data request ORA-135, Q. 3.

case for a pension fund contribution in its next GRC, assuming that investment markets continue to perform poorly.

B. Postretirement Benefits Other Than Pensions (PBOPS)

PG&E requests $64.5 million for postretirement benefits other than pensions (PBOPS). The Commission's PBOPS accounting and ratemaking policies were adopted in D.92-12-015. FAS 106 governs the financial accounting and reporting for PBOPS.

PG&E requests $60.3 million for PBOPS Medical based on its calculation of the FAS 106 expense that can be contributed to a qualified trust on a tax-deductible basis. In addition, PG&E requests $4.3 million for PBOPS Life based on PG&E's forecast tax-deductible trust plan contribution and its costs that cannot be paid from the trust. PG&E's plan actuary, Towers Perrin, forecasts a tax-deductible contribution to the trust for test year 2003 of $3.2 million.

In adopting test year forecasts for PBOPS medical and life insurance, the Commission has held that amounts included in rates that are not used for the intended purpose are to be returned to ratepayers at the end of the general rate case cycle through an advice letter filing. For PG&E's last two general rate cases, PG&E overestimated and overcollected in rates for PBOPS.

ORA has reviewed PG&E's request for PBOPS funding and does not find it unreasonable. ORA's agreement with PG&E's forecast is due in part to the Commission's practice of ordering ratepayer refunds for overcollected amounts.

C. Savings Plan

D. PG&E estimates test year expense for its savings plan to be $33.7 million based on 2001 recorded costs.[15] ORA reviewed PG&E's testimony,

[15] Exhibit PG&E-4, p. 5-41.

workpapers and responses to data requests and does not take exception to PG&E's estimate for its savings plans.

E. Medical Plans

PG&E estimates test year expense for its medical plans to be $134.9 million nominal dollars or $104.4 in constant 2000 dollars. PG&E's medical plans consist of healthcare plans (including Point-of Service (POS), Preferred Provider Organization (PPO), and Health Maintenance Organizations (HMOs)), a prescription drug plan, an employee assistance program (EAP), a mental health, alcohol and drug care program, and a drug testing program. These programs are described by PG&E in Exhibit PG&E-4, pages 5-7 to 5-19.

PG&E forecast its test year 2003 expense by assuming that its expenses will be equal to its 2001 cost in constant dollars.[16] PG&E then used the DRI/WEFA forecast of "Employment Cost Index, Health Insurance" (ECIHI) drawn from DRI/WEFA's second quarter 2002 Cost Information Service forecast to escalate its expenses by 10.39% and 7.68% for 2002 and 2003, respectively.[17]

ORA's analysis, based on 2002 recorded amounts, shows that PG&E's actual experience from 2001 to 2002 was an increase of 5.12% in expenses for its medical plans. This is less than half of the 10.39% increase predicted using DRI/WEFA's ECIHI. Therefore, ORA recommends beginning with the recorded 2002 expenses of $119.3 million and escalating the 2002 recorded amount using DRI/WEFA's ECIHI of 7.68% for 2003. The result is $128.423 million in nominal dollars. In order to accommodate the RO model and to present ORA's estimate on a comparable basis to PG&E, ORA calculated its model input number by de-escalating the nominal

[16] Exhibit PG&E-4, pp. 5-9 to 5-15.

dollar amount to 2001 dollars. The result of that calculation is $106.242 million. The comparable 2000 constant dollar amount of $98.4 million is then calculated through the RO model.

F. Dental Plan

PG&E estimates test year 2003 expense for its Dental Plan to be $20.4 million.[18] PG&E projected test year 2003 expenses by taking recorded adjusted 2001 expenses and escalating to 2002 using an escalation factor of 3.3%, then escalating from 2002 to 2003 using an escalation factor of 3.5%. PG&E's Dental Plan administrator, Delta Dental, supplied the escalation factors.[19] PG&E's adjustments to 2001 recorded consisted of adjusting for Wave 1 and 2 O&M contracts and truing up booked accrual for actual.

ORA's analysis, based on 2002 recorded amounts, shows that PG&E's actual experience from 2001 to 2002 was a 7.6% decrease in expenses for natural account 5200130, Employee Welfare – Dental Plan. Therefore, ORA recommends escalating the 2002 recorded amount of $17.6 million by 3.5% resulting in an estimated test year 2003 expense of $18.2 million. ORA's test year estimate is $2.2 million or 10.8% less than PG&E's test year 2003 estimate of $20.4 million.

G. Vision Plan

PG&E estimates test year 2003 expense for its Vision Plan to be $3.3 million.[20] PG&E projected test year 2003 expenses by taking recorded adjusted 2001 expenses and escalating to 2002 using an escalation factor of 2.5%, then escalating from 2002 to 2003, again using an escalation factor of 2.5%. PG&E's Vision Plan administrator, VSP, supplied the escalation

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[17] Exhibit PG&E-7 p. 3-10.
[18] Exhibit PG&E-4, p. 5-20.
[19] Exhibit PG&E-4 workpapers for Administrative and Support Costs, Chapter 5, Pensions and Benefits, p. 5-8.

factors.[21] PG&E's adjustments to 2001 recorded consist of adjusting for Wave 1 and 2 O&M contracts and truing up booked accrual for actual.

ORA's analysis, based on 2002 recorded amounts, shows that PG&E's actual experience from 2001 to 2002 was a 14.8% decrease in expenses for natural account 5200150, Employee Welfare – Vision Plan. Therefore, ORA recommends escalating the 2002 recorded amount of $2.67 million by 2.5% resulting in an estimated test year 2003 expense of $2.73 million. ORA's test year estimate is $0.6 million or 18.2% less than PG&E's test year 2003 estimate of $3.3 million.

H. Long Term Disability

PG&E forecasts test year 2003 expense of $61.9 million based on the forecast contribution to the long term disability (LTD) trust calculated by PG&E's plan actuary, Towers Perrin. FAS 112 – Employers' Accounting for Postemployment Benefits prescribes the financial accounting and reporting for long-term disability benefits. FAS 112 established standards for financial accounting and reporting for the estimated cost of benefits provided by an employer to former or inactive employees after employment, but prior to retirement. FAS 112 amends FAS 5 – Accounting for Contingencies and FAS 43 – Accounting for Compensated Absences.

PG&E adopted FAS 112 effective January 1994.[22] FAS 112 requires accrual accounting for postemployment benefits. Upon adoption of FAS 112, PG&E incurred a liability for the full amount of the initial transition obligation. The Commission included funding for these benefits in D.95-12-055 and in D.00-02-046. In 1994, the initial transition obligation, which

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[20] Exhibit PG&E-4, p. 5-21.

[21] Exhibit PG&E-4 workpapers for Administrative and Support Costs, Chapter 5, Pensions and Benefits, p. 5-10.

[22] Exhibit PG&E-7, p. 5-32.

normally would have been recognized, was deferred into a regulatory asset under the provisions of FAS 71 – Accounting for the Effects of Certain Types of Regulation. PG&E has been amortizing the initial transition obligation over 20 years beginning in 1996.

On January 1, 2000, PG&E adopted a plan design change that reduced the recorded LTD liability. The company recognized the regulatory impact of the change by recording a liability as an offset to the initial transition obligation regulatory asset. PG&E indicates that this will shorten the length of the remaining amortization on the regulatory asset from sixteen years to approximately six years.[23] The plan change is a non-cash event that reduced the liability for LTD benefits on the company's books.

Pursuant to D.95-12-055, amounts included in rates for contributions to the LTD fund may not be used for purposes other than postemployment benefits and amounts included in rates that are not contributed to the LTD fund must be refunded to ratepayers.[24] Given that, ORA does not take exception to PG&E's forecast for LTD.

I. Group Life Insurance

J. PG&E estimates test year expense for its group life insurance plan to be $2.3 million based on plan experience in 2001 and the transition to a non-participating contract with its vendor, Metropolitan Life.[25] ORA reviewed PG&E's testimony, workpapers and responses to data requests and does not take exception to PG&E's estimate for its group life insurance plan.

K. Relocation Expense

PG&E forecasts test year 2003 expense of $3.1 million based on anticipated 2002 relocation expenses of $3.2 million and 2000 recorded

[23] Exhibit PG&E-7, p. 2-10.
[24] D.95-12-055 (63 CPUC 2d, p. 595).

expenses.[26] PG&E's 2000 recorded adjusted expense for relocation expense was $3.114 million.

ORA's analysis, which included 2002 recorded amounts, shows that PG&E's recorded adjusted expense declined to $2.292 million in 2001, a decline of 44%. PG&E's 2002 recorded expense for relocation is $2.444 million, down 21.5% from 2000 levels. PG&E's forecast for 2002 relocation expense is 31% higher than PG&E's recorded 2002 relocation expense. ORA recommends the Commission adopt test year 2003 relocation expense forecast of $2.366 million to reflect PG&E's most recent actual experience regarding relocation expense.

L. <u>Tuition Refund</u>

PG&E forecasts test year 2003 expense for tuition refund of $1.6 million (nominal dollars). PG&E's forecast is based on the average refund per program participant over historical years 1997 through 2001 and the number of program participants for 1999. PG&E contends that program participation for 2000 and 2001 was abnormally low because of the energy crisis and bankruptcy.[27] PG&E's forecast anticipates that enrollment numbers in 2003 will rebound to 1999 levels.

ORA analyzed historical data for the years 1997 through 2002. Activity levels experienced in 2002 do not support PG&E's contention that enrollment levels would return to 1999 levels by the test year. Data for 2002 shows that enrollment levels in the tuition refund programs are down 34% from 1999 levels. ORA recommends the Commission adopt a test year 2003 expense for tuition refund of $1.1 million. ORA's recommendation for test

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[25] Exhibit PG&E-4, p. 5-23.
[26] Exhibit PG&E-4, p. 5-43.
[27] Exhibit PG&E-4 Workpapers, P. 5-61.

year 2003 is based on the most recent five-year average refund per program participant (1998-2002) and the 2002 participation level.

M. Service Awards

PG&E forecasts test year expense for service awards of $837,000,[28] while the corresponding ORA estimate is $0. PG&E's forecast is based on year 2001 award selections, anticipated numbers of participants eligible for awards in 2003, and contract terms with its program administrator. According to PG&E, the Service Awards Program provides special recognition to employees based on continuous service.[29] An outside vendor administers the program.

The Commission has a lengthy history of denying utility requests for these types of benefits (D.67369, 62 CPUC 851-854; D.89-12-157, 34 CPUC 2d 265-266; and D.93-12-043, 52 CPUC 2d, 513-514). The Commission has found that such rewards fit the category of social activities and should not be funded by ratepayers. In this case, ORA recommends that the Commission adhere to its past precedent and policy and deny PG&E's request for service awards. This results in an adjustment to PG&E's request of $837,000 for service awards from its test year 2003 forecast to $0 as proposed by ORA.

N. Flexible Benefits Program

O. PG&E estimates test year expense for its Flexible Benefits Program to be ($535,000) based on 2001 program costs and 2003 anticipated employee contributions.[30] ORA reviewed PG&E's testimony, workpapers and responses to data requests and does not take exception to PG&E's estimate for its Flexible Benefits Program.

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[28] Exhibit PG&E-4, p. 5-43.
[29] Exhibit PG&E-4, p. 5-43.

II. IV. CONCLUSIONS

ORA recommends that the Commission adopt its estimate of test year 2003 expense for Account 926 – Pensions and Benefits. ORA's estimate is based on more recent recorded data. In addition, ORA excludes PG&E's forecast contribution to its pension fund in the test year from ORA's estimate. ORA's test year 2003 estimate for Account 926 adds up to $287.3 million on a total company basis. This is $139.5 million less than PG&E's estimate of $426.7 million on a total company basis.

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[30] Exhibit PG&E-4, p. 5-25.

CHAPTER 10-F

INSURANCE AND INJURIES AND DAMAGES

I. INTRODUCTION

In this chapter, ORA presents its analysis, estimates, and recommendations on A&G Expenses for FERC Accounts 924 (Property Insurance) and 925 (Injuries and Damages). PG&E sets forth its requests for Insurance and Injuries and Damages in Exhibit PG&E-4, Chapter 3 ("Insurance and Other A&G Costs) and PG&E-6, Volume 1, Chapter 2, Workpapers. This chapter presents ORA's analysis of the company's proposal and presents recommendations in response to PG&E's request.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, Sections III and IV present ORA's analysis of FERC Accounts 924 (Property Insurance) and 925 (Injuries and Damages) and support for ORA's forecasts and adjustments, and Section V provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

After reviewing PG&E's Property Insurance estimates for FERC Account 924, ORA recommends total adjustments of $4,641,143 to PG&E's TY2003 request. Specifically, ORA proposes an adjustment credit of $7,153,939 to PG&E's TY2003 request for the Diablo Canyon All Risk Nuclear Property Insurance in recognition of historically higher nuclear insurance refund amounts than estimated by PG&E. This results in a $4,467,939 increase in the nuclear insurance refund, and therefore a respective decrease in the total Property Insurance Estimate. For Account 925, Injuries and Damages, PG&E recommends a forecast of $79,252,000 on a Total Utility basis, while the corresponding ORA estimate is $66,702,000. ORA recommends that the

Commission adopt a 50/50 sharing between ratepayers and shareholders for expenses associated with Directors and Officers Liability Insurance, which results in an adjustment of $2,199,000 to PG&E's TY2003 request for Injuries and Damages expenses in Account 925. In addition, ORA recommends the use of the three-year averaging method to appropriately estimate Third Party Claims, which results in a $2,735,000 adjustment to PG&E's TY2003 estimate. Lastly, ORA also proposes the use of the three-year averaging method to estimate Settlements and Damages, which results in a $6,957,000 adjustment to PG&E's TY2003 estimate of $20,198,000.

Table 10-F-1 presents the differences between ORA's and PG&E 's projections of TY2003 Insurance and Injuries and Damages expenses:

TABLE 10-F-1
INSURANCE AND INJURIES AND DAMAGES
TOTAL UTILITY
(2000 Constant Dollars in thousands)

FERC Account	ORA	PG&E	PG&E>ORA	Percent
924	10,710	15,351	4,641	30.2%
925	66,702	79,252	12,550	15.8%

III. DISCUSSION/ANALYSIS: INSURANCE EXPENSES

In its filing and in data responses, PG&E discusses the impacts of general insurance industry losses due to stock market losses, diminished investment income and the effects of the events of September 11, 2001 on risk exposure assessment for the property insurance market:

> Insurance industry issues described in Chapter 3 of Exhibit (PG&E-4) and in the responses to earlier data requests (i.e. diminished reinsurance capacity, especially for earthquake coverage in California at a reasonable cost, the significant impact of September 11, 2001, the industry-wide loss

experience, and losses in insurance company investment income) continue to have a negative impact on property insurance premiums.[1]

According to PG&E, losses have exceeded premiums over the last several years, and larger investment returns in recent years had allowed for more liberal underwriting of policies for lower rates. However, PG&E also states "since stock market prices peaked in early 2000, insurance companies investment returns have declined dramatically, requiring insurers to increase premiums and deductibles in order to maintain profitability."[2] PG&E's request for Total Property Insurance for TY2003 is $15,350,964.

ORA conducted its analysis of the insurance market by reviewing PG&E's testimony and supporting workpapers, issuing data requests, and examining responses. ORA also met with PG&E's A&G witnesses for Insurance and conducted telephone conferences to obtain further information, clarification, and details on the above materials. Finally, ORA reviewed studies relevant to the liability insurance market provided in data responses as additional support for PG&E's request and calculations. Table 10-F-2 provides a more detailed breakdown of the Property Insurance Forecast Increases for TY2003[3]:

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[1] Excerpted from p. 1 of PG&E's response to Question 5 of Data Request C-PSP-184.

[2] P. 3-3, Exhibit PG&E-4.

[3] Table 10-F-2 is taken directly from p. 6-146, Exhibit PG&E-6, Chapter 6, Vol. 1.

TABLE 10-F-2 Property Insurance Forecast Increase (2000 Constant Dollars in Thousands)	
All Non-Nuclear Property Insurance	**TY2003**
Aircraft Hull	51
All Risk	17,499
Blanket Crime/Employee Dishonesty	336
Boiler/Machinery Breakdown	0
Business Travel (Named Aircraft)	12
Business Travel (Public Conveyance)	36
Cargo/Oil & Equipment	12
Miscellaneous Bonds	430
Transfer Agent's Mail/Lost Instrument	0
Subtotal Non-Nuclear Prop. Ins	18376
All Risk Property - Humboldt Bay	(141)
All Risk Property - Diablo Canyon	(2,885)
Total Property Insurance	**15,350**

A. <u>Diablo Canyon and Humboldt Bay all Risk Nuclear Property Insurance Refund</u>

ORA does not take issue with PG&E's estimated premium expense increases for Non-Nuclear and Nuclear Property Insurance coverage. The losses incurred by all insurers have resulted in higher premiums for All Risk Non-Nuclear Property Insurance, and slightly higher increases in Nuclear Property Insurance premiums. In the case of Nuclear Electric Insurance Limited (NEIL), lower returns on investment

decreased refunds for All Risk Property Insurance for Diablo Canyon and Humboldt Bay in 2002. PG&E's TY2003 Diablo refund estimate of $2,884,597 is approximately $3.33 million, or 53.6% less than the refund estimate for 2002. Also, according to PG&E, the $141,118 estimated refund for the Humboldt Bay Nuclear facility "reflects an expected 10 percent increase in premium costs."[4] This expected 10% Nuclear Property Insurance premium expense increase for PG&E is substantially below the expected 25% increase in the Total All Risk Property Insurance renewal premium costs in 2003.[5]

In view of the overall historical variation in Nuclear Insurance refunds, ORA believes that a five-year average yields the most appropriate refund estimate for TY2003. Table 10-F-2 shows the five year historical expense data for Total Non-Nuclear and Nuclear Property Insurance:

TABLE 10-F-3[6]

HISTORICAL PROPERTY INSURANCE COVERAGE, 1998-2002

Coverage	1998	1999	2000	2001	2002	5-Year Avg
Total Non-Nuclear	$10,603,825	$ 8,185,523	$ 10,436,030	$ 10,241,445	$12,677,253	$ 10,428,815
Nuclear (Humboldt)	$ (235,730)	$ (238,306)	$ (492,028)	$ (464,428)	$ (275,000)	$ (314,322)
Nuclear (Diablo)	$ (4,301,432)	$ (4,731,240)	$(10,518,732)	$(10,000,592)	$ (6,217,698)	$ (7,153,939)
Total Prop. Ins.	$ 6,066,663	$ 3,215,977	$ (574,730)	$ (223,575)	$ 6,184,555	$ 2,960,554

Given PG&E's expected premium increase of 10% between 2002 and 2003 for these two nuclear facilities, it is logical to assume that

[4] *Ibid*, p. 2 (response to Question 5).

[5] See p. 6-146, Exhibit PG&E-6, Volume 1 (Workpapers) for 2002 and 2003 All Risk estimates.

[6] The 1998-2001 figures were taken from Attachment ORA_0184-05-1 to PG&E data response ORA_0184-05. See p. 6-146, Exhibit PG&E-6, Volume 1 (Workpapers) for 2002 data.

the risk exposure for these facilities is not expected to be as high as the risk associated with Non-Nuclear properties. Furthermore, despite the stock market volatility and the consequent declining returns on investment on property insurance premiums, it appears that NEIL will not be affected as dramatically for nuclear coverage as many of the companies offering non-nuclear property insurance coverage.

While the nuclear insurance refund declined only marginally from 2001 to 2002 (approximately 6.0%) for Diablo Canyon, the subsequent decline in the refund estimated by PG&E from 2002 to 2003 is a dramatic 71%.[7] Such a significant projected decrease in the Diablo nuclear refund is arbitrarily large and is not consistent with the apparent 10% increase in nuclear premiums. This is especially unjustifiable when considering that the 25% increase in the All Risk Property Insurance renewal premiums have resulted in a much more conservative estimate of $2,435,808, or 23.8% increase in Total Non-nuclear insurance. Additionally, PG&E states in a data request response that NEIL expects "a 38% reduction in its 2003 distribution from its 2002 levels." Based on these numbers, PG&E's 71% decrease in the Diablo nuclear refund is overstated and should be adjusted based on historical data.

As a result of historical variability and PG&E's anticipated dramatic decline in expected refunds from 2002 to 2003, ORA recommends that the Commission adopt the 5-year average for the nuclear insurance refund. This methodology incorporates the impacts of variability from year to year to arrive at a normalized estimate for ratemaking purposes. Table 10-F-4 below shows the differences between

[7] See p.6-146, Exhibit PG&E-6, Vol. 1 Workpapers. The 2002 estimate for the nuclear refund is $6,217,698, and the 2003 estimate has been updated to $5,975,000, per PG&E data response Attachment ORA_0184-05-1.

the 5-year average and PG&E's revised estimates for the total nuclear refund for Diablo Canyon and Humboldt Bay:

TABLE 10-F-3 REVISED TY2003 NUCLEAR ESTIMATES VS. 5-YEAR AVERAGE			
Nuclear Facility	5-Year Avg	PG&E TY2003 Estimates	Difference
Diablo Canyon	$ 7,153,939	$ 2,884,597	$ 4,269,342
Humboldt Bay	$ 314,322	$ 141,118	$ 173,204
Total Nuclear	$ 7,468,261	$ 3,025,715	$ 4,442,546

IV. DISCUSSION/ANALYSIS: INJURIES AND DAMAGES

PG&E's request for Injuries and Damages is comprised of the following components: (1) estimates for general liability and Directors and Officers Liability (D&O) based on current insurance market conditions and premiums; (2) the estimate for Workers' Compensation costs, as developed by PG&E's Safety, Health, and Claims (SH&C) Department, based on 2000 recorded data adjusted for anticipated medical cost increases; (3) the estimate for settlements and damages costs as developed by PG&E's Law Department, which is based on 2000 recorded adjusted data and is expected to remain at 2000 levels; and (4) the estimate for Third Party Claims, which is based on the 5-year average.[8]

ORA conducted its analysis of Injuries and Damages by reviewing PG&E's testimony and supporting workpapers, issuing data requests, and examining responses. ORA also met with PG&E's A&G witnesses and conducted telephone conferences to further discuss the above materials for clarification. Finally, ORA reviewed studies relevant to the liability insurance market provided in data responses as additional support for PG&E's request and calculations.

[8] Paraphrased in summary from pp. 3-6—3-7, Exhibit PG&E-6.

As with the Property Insurance estimates, PG&E asserts that the liability and D&O insurance premiums have increased significantly as a result of losses in the insurance industry precipitated by declining stock prices and investment income. In addition, expected increases in Workers' Compensation and Third Party Claims are other primary expense drivers in PG&E's total request for Account 925.

A. D&O Liability Insurance Expense

PG&E has forecasted TY2003 expenses of $2,689,000 for D&O Liability insurance in Account 925. This projection is 71% greater than PG&E's recorded expense of $1,572,000 for 2002. PG&E's Insurance Department assessed current insurance market conditions and increased premiums, and met with insurers in developing this estimate.[9] Table 10-F-5 below summarizes historical D&O Liability expenses and presents the three-year average:

[9] See p.3-6, Exhibit PG&E-4

TABLE 10-F-5 Directors and Officers Liability Insurance (2000 Constant Dollars in Thousands)	
Year	Amount
2000	778
2001	591
2002	1572
3-Year Average (ORA)	980
TY2003 estimate (PG&E)	2689
Difference b/w Avg. and TY2003	1709
ORA Recommended 50% Split	490

ORA recommends a 50% adjustment to the three-year average D&O Liability insurance expense, or $490,000, as shareholders should be responsible for half of this liability expense. ORA also elected to utilize the three-year average in view of the annual variation from 2000-2002. Ratepayers should not be made to automatically cover the entirety of this component of PG&E's liability insurance expense. Rather, shareholders should bear a fair portion of the potential risks surrounding corporate liability. Since shareholders directly benefit from D&O liability coverage to the extent that insulation against liability claims aids in sustaining PG&E's financial health, and ultimately their ability to pay stock dividends, they should share this insurance expense with ratepayers. The Commission has previously ruled in favor of this recommended 50% adjustment in PG&E's GRC D.00-02-046, as well as in D.96-01-011 for the 1995 Southern California Edison GRC. The

Commission should remain consistent with these past Decisions and adopt the 50% adjustment to D&O Liability Insurance expense. In addition, the Commission should make this adjustment to ORA's recommended three-year average, in recognition of PG&E's historically variable D&O Liability Insurance expenses.

B. <u>Third Party Claims</u>

PG&E's Safety Health and Claims (SH&C) Department developed its Third Party Claims estimate for TY2003 by taking the five-year average of recorded data for 1997-2001, or approximately $11,768,000.[10] To support the use of this method, PG&E explains the following:

> Although the 2001 recorded level of Third Party Claims was lower than 2000 recorded, PG&E believes that this was caused by the public's perception that PG&E's financial condition precluded the Company's paying Third Party Claims. Thus, PG&E believes a five-year average is the most reasonable method for estimating 2003 Third Party Claims. In the 1999 GRC Decision, the Commission adopted the use of a five-year average to estimate Third Party Claims, finding it "appropriate given the annual fluctuations associated with the underlying claims and settlement costs."[11]

ORA does not agree with PG&E's estimate because PG&E's assumptions regarding the public's perception of PG&E's financial condition and the finding from the 1999 GRC Decision simply do not adequately support the use of the five-year averaging method. First, there is no way of knowing in precise terms the extent to which negative public perceptions about PG&E's ability to fulfill its financial obligations precipitate declining Third Party Claims. Second, the historical Third

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[10] P. 6-167, Exhibit PG&E-6.

[11] P. 3-7, Exhibit PG&E-4 (also, ref. D.00-02-046, *supra* at p.304).

Party Claims figures dating back to 1998 reflect a significant downward trend through 2001 rather than the fluctuations that apparently fit the previous five-year trend in the 1999 GRC. ORA recommends the use of the Last Recorded Year method to estimate Third Party Claims for 2002, which were recorded at $8,373,884[12], or $3,394,000 less than PG&E's five-year average estimate. Given the increase in 2002 after a significant downward trend in historical data through 2001, ORA believes the Last Recorded Year is the most reasonable estimate for TY2003. This estimate reflects the latest recorded data and is somewhat higher than the three-year average (of recorded 2000-2002) data of $7.3 million. The ORA forecast is clearly a conservative estimate based on the most current data. Additionally, as PG&E's inability to project within a range of reasonableness the extent to which public perception of PG&E's ability to honor Third Party Clams fails to adequately support the use of the five-year average, it should not be used. If indeed this perception is in any part responsible for the increase in total claims from 2001 to 2002, then the 2002 total should be considered the most reliable estimate going forward.

Table 10-F-4 provides a snapshot of the last six years of Third Party Claims data for reference:

[12] ORA calculated the summary of monthly Third Party Claim recorded data for 2002, per ORA's Audit staff report (spreadsheet PG&E Monthly Account Changes from May96-Dec02.xls).

TABLE 10-F-6 THIRD PARTY CLAIMS, TY2003	
1997	$ 14,586
1998	$ 17,566
1999	$ 13,531
2000	$ 8,806
2001	$ 4,762
2002	$ 8,374
PG&E	$ 11,768
ORA Recommendation	**$ 8,374**
PG&E>ORA	**$ 3,394**

C. Settlements and Damages

PG&E's Law Department developed the estimate for Settlements and Damages costs based on 2000 recorded adjusted data. There has been considerable variability in these costs over the past three years, which may be associated with PG&E's bankruptcy. ORA recommends the use of the three-year average as a result of the historical variability in recorded adjusted expenses between 2000 and 2002. Table 10-F-5 below presents these expenses for Settlements and Damages and the three-year average:

TABLE 10-F-7 Settlements and Damages (2000 Constant Dollars in Thousands)	
2000RA	20,198
2001RA	401
2002RA	19,124
Total	39,723
TY2003 PG&E Estimate	**20,198**
Avg. (ORA Recommendation)	**13,241**
PG&E > ORA	**6,957**

ORA therefore recommends an adjustment of $6,957,000 to PG&E's TY2003 estimate of $20,198,000.

D. <u>Summary</u>

Table 10-F-5 below provides a summary of PG&E's estimates and ORA's recommended adjustments:

TABLE 10-F-8 INSURANCE AND INJURIES AND DAMAGES ADJUSTMENTS		
Account	**Description**	**Estimate**
924	**PG&E's Estimate**	**$ 15,351,000**
	5-Yr. Avg. Diablo – TY2003 (Differential)	$ (4,467,939)
	5-Yr. Avg. Humboldt – TY2003 (Differential)	$ (173,204)
	ORA Recommendation	**$ 10,709,857**
	PG&E > ORA	**$ 4,641,143**
925	**PG&E's Estimate**	**$ 79,252,000**
	50/50 Sharing D&O Adjustment	$ (2,199,000)
	Third Party Claims Adjustment	$ (3,394,000)
	Settlements and Damages	$ (6,957,000)
	ORA Recommendation	**$ 66,702,000**
	PG&E > ORA	**$ 12,550,000**

V. CONCLUSION

ORA recommends an overall adjustment of $4,641,143 to Account 924 for the differential between ORA's recommended five-year averaging method to estimate the nuclear refund for the two nuclear facilities and PG&E's estimates.

ORA also recommends an overall adjustment of $12,550,000 to Account 925 for (1) the 50% sharing adjustment to the three-year average D&O Liability Insurance expense, to be absorbed by shareholders, (2) the differential between ORA's recommended three-year averaging method for Third Party Claims and PG&E's TY2003 estimate, and (3) the differential between ORA's recommended three-year averaging method for Settlements and Damages and PG&E's TY2003 estimate. Table 10-F-4 shows the adjustments to the two

accounts in further detail. In summary, ORA recommends $17,191,143 in adjustments, or approximately 10.8% of the total.[13]

[13] The total estimated for both accounts is $94,603,000.

CHAPTER 10-G

OTHER ADMINISTRATIVE AND GENERAL ACCOUNTS

I. INTRODUCTION

In this chapter, ORA presents its analysis, estimates, and recommendations on A&G Expenses for FERC Accounts 927 (Franchise Fees), 928 (Regulatory Commission Fees), 930 (Miscellaneous and General Expenses), and 935 (Maintenance of General Plant). PG&E sets forth its requests for these A&G Accounts in Exhibit PG&E-4, Chapter 3 ("Insurance and Other A&G Costs) and PG&E-6, Volume I, Chapter 2, Workpapers. This chapter presents ORA's analysis of the company's proposal and presents recommendations in response to PG&E's request.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, Sections III -- V present ORA's analysis of FERC Accounts 927, 928, 930, and 935, and support for ORA's forecasts and adjustments, and Section VI provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

After analyzing PG&E's estimates, workpapers, justifications, and data request responses for these four A&G accounts, ORA recommends the following:

1) ORA does not take issue with PG&E's requests for Accounts 927 and 928, and therefore makes no adjustments to the Franchise Fee factor calculations or the projections for Regulatory Commission

fees, which are removed from Account 928 for GRC forecasting purposes.[1]

2) For Account 930, ORA recommends adjustments of $78,200,000 for the removal of Public Purpose Program expenses,[2] $4,294,080 for the removal of an MCI Exchange of Rights Fee, and approximately $81,333 for various other items that should not be funded by ratepayers.

3) For Account 935, ORA proposes an adjustment of $1,668,104 to reflect the difference between PG&E's estimate and ORA's recommended three-year average for all maintenance expenses.

Table 10-G-1 presents the differences between PG&E's and ORA's projections of TY2003 for FERC Accounts 927, 928, 930, and 935:

TABLE 10-G-1

OTHER A&G ACCOUNTS

(2000 Constant Dollars in Thousands)

FERC Account	ORA	PG&E	PG&E>ORA	Percent
927	0	0	0	0
928	0	0	0	0
930 (Total)	86,710	91,285	4,575	5.0%
Public Purpose Programs	78,200	78,200	0	0
Other	8,510	13,085	4,375	35.0%
935	6,711	11,233	4,522	40.30%

[1] See pp. 6-241-6-243 of Exhibit PG&E-6, Chapter 6, Volume 1 Workpapers, which shows the removal of CPUC Debt Fee Placement, and Diablo and Humboldt Bay Regulatory fees.

[2] The Public Purpose Program expenses are not included in PG&E's historical recorded adjusted accounting data, and therefore will not be included in ORA's RO model calculations.

III. DISCUSSION/ANALYSIS: ACCOUNTS 927 (FRANCHISE FEES) AND 928 (REGULATORY COMMISSION EXPENSES)

PG&E shows its calculations for Franchise Fees factors in workpapers, which ultimately end up being applied in the revenue requirement calculation, and so FERC Account 927 retains no estimates, requires no further analysis, and therefore ORA takes no issue with the factor calculations. Accounts 927 and 928 expenses have remained stable for the most part since 2000. Similarly, ORA takes no issue with the Regulatory Commission Fees expenses presented for Account 928, which is zeroed out after these Commission Fees are either removed, transferred to other accounts, as is the case with the Diablo fees, or addressed in another proceeding.[3]

IV. DISCUSSION/ANALYSIS: ACCOUNT 930 (MISCELLANEOUS AND GENERAL EXPENSES)

ORA proposes making a few adjustments to Account 930, the largest of which is removing $78,200,000 for Public Purpose Program (PPP) expenses, which are addressed in a separate proceeding, and not reviewed here. PG&E developed estimates for Account 930 based primarily on 2000 Recorded Adjusted (RA) data, with the exception of bank fees, which is almost doubled from $1,874,107 (2000 RA) to the 2003 estimate of $3,635,663.

A. <u>Public Purpose Programs</u>

The removal of $78,200,000 is a necessary, routine adjustment of a historically stable set of costs and overall budget for various programs, such as the California Energy Efficiency program. Like the Regulatory

Commission expenses for the Humboldt Bay nuclear facility, the merits of these PPP budget estimates are addressed in much greater detail in a separate, more appropriate proceeding, and not reviewed in this case. PG&E's Recorded Adjusted SAP/Natural Accounting data for years prior to 2002 show the removal of this entire amount from Account 930 in a single line item adjustment.

B. <u>MCI Exchange of Rights Fee</u>

ORA analyzed PG&E's filing and sent a data request to PG&E for more information regarding a specific line item, described in PG&E's SAP natural account data as the "MCI Exchange of Rights Fee" for $4,294,080.[4] This particular item was questionable for a couple of reasons: (1) it was a fairly large expense with little description through which to gauge its relevance to expenses for which ratepayers should be held responsible, and (2) the line item appeared to recur for an unknown period of time, which needed clarification and support. PG&E's response to a data request stated that these charges were "the result of a non-monetary exchange between MCI and PG&E. PG&E entered into a Commission-approved agreement with MCI allowing MCI to attach fiber optic cables to PG&E electric transmission facilities in exchange for PG&E using telecommunications capacity on MCI's network."[5]

The MCI Exchange of Rights expense thus involves non-monetary transactions between MCI and PG&E. Consequently, it is shown on PG&E's financial books for tax purposes in the form of a credit to Other

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[3] Regulatory expenses for Humboldt Bay Nuclear Unit 3 are addressed in the Nuclear Decommissioning Cost Triennial Proceeding, and are therefore removed from 928.

[4] ORA spoke to both Overland Consulting and PG&E in a telephone conference about this line item, and were referred to an Overland data request and PG&E's response regarding the need for removal of this item from the natural accounts. (item # 5001161 – MCI Exchange of Rights Expense)

[5] Response to Overland Data Request No. OC-276

Operating Revenues (OOR), and an equivalent debit to Account 930. However, PG&E's GRC estimates for Account 930 included this debit under the assumption that the credit had been removed from OOR, when in fact it hadn't. Therefore, while the complete transaction shows up in recorded data for 2002, only the debit to 930 is factored into estimate for TY2003, when it should be removed. An investigation of this line item resulted in the routine removal of this fee as a result of what appeared to be a deficiency in PG&E's natural accounting data.

C. <u>Miscellaneous Natural Account Adjustments</u>

As explained by PG&E in its filing, Account 930 contains a variety of expenses for items such as certain "dues, subscriptions, bank fees, expenses related to services to bondholders and shareholders for transfer agent, registrar, and trustee activities and for stock exchange fees, employee publications, advertising, directors' fees and expenses, and certain clearing expenses."[6] Most of the overall increase in Account 930 from 2000 Recorded Adjusted data is due to increased Mellon Bank fee rates, stipulated in a January 2001 Service Agreement.[7] ORA does not take issue with PG&E's anticipated increase in bank fees.

ORA does however take issue with items such as club dues, subscriptions, and entertainment expense, located in PG&E's recorded natural account data for 2002. Table 10-G-2 presents those line items as found in PG&E's natural accounts:

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[6] P.3-7, Exhibit PG&E-4

[7] Per the Service Agreement, once out of bankruptcy, PG&E is slotted to pay an additional fee increase of 18.75 basis points, which is included in this forecast.

TABLE 10-G-2 NATURAL ACCOUNT ADJUSTMENTS FOR 930	
Company Membership Fees	$22,697
Entertainment Expense	$7,000
Cash Rewards & Recognition	$6,414
Misc General Expense – Subscriptions	$10,251
Misc General Expense – Assoc. Dues	$25,572
Club Dues	$9,400
Total	**$81,334**

Ratepayers should not pay for these or other similar items as they are clearly not in any way serving to benefit ratepayers. For Cash Rewards & Recognition, ORA maintains that like other similar items, all such employee rewards should be paid for by shareholders. Allowing PG&E to pass such expenses through to ratepayers also provides no incentive to prudently and efficiently manage these types of expenses.

D. <u>Total Adjustments to Account 930</u>

The following table summarizes the total adjustments proposed by ORA for Miscellaneous and General Expenses:

TABLE 10-G-3 SUMMARY ADJUSTMENTS TO ACCOUNT 930	
Description	TY2003
PG&E's Estimate	$ 91,285,000.00
Public Purpose Programs	$ (78,200,000.00)
MCI Exchange of Rights Expense	$ (4,294,080.00)
Total Misc. Natural Accounts Adjust.	$ (81,333.74)
Total -- ORA's Recommendation	**$ 8,709,586.26**
Difference (PG&E - ORA)	**$ 82,575,413.74**
Difference (Excluding PPP)	**$ 4,375.00**

V. DISCUSSION/ANALYSIS: ACCOUNT 935 (MAINTENANCE OF GENERAL PLANT)

PG&E's proposed 125% increase for TY2003 is mainly the result of various projected seismic upgrades to facilities. However, since PG&E has failed to complete or start several estimated projects in 2002, ORA recommends the utilization of the Last Recorded Year (2002) Method for estimating Account 935. Using recorded 2002 data as an estimate for TY2003, the revised total estimate is approximately $6,678,895, or 40.5% lower than PG&E's projected $11,233,000. This figure is very similar to the three-year average for Account 935, which is approximately $6,711,000.

Table 10-G-4 below summarizes the Other A&G Account totals and ORA's proposed adjustments:

TABLE 10-G-4 SUMMARY ADJUSTMENTS TO OTHER A&G ACCOUNTS		
Account	Description	TY2003
927	PG&E's Estimate	$ -
	ORA's Recommendation	$ -
928	PG&E's Estimate	$ -
	ORA's Recommendation	$ -
930	PG&E's Estimate	$ 91,285,000
	Public Purpose Programs	$ (78,200,000)
	MCI Exchange of Rights Expense	$ (4,294,080)
	Total Misc. Natural Accounts Adjust.	$ (81,334)
	Total -- ORA's Recommendation[8]	**$ 8,709,586**
	Difference (PG&E - ORA)	**$ 82,575,414**
935	PG&E's Estimate	$ 11,233,000
	Less difference b/w 2002 and TY estimate	$ (4,554,104)
	Last Recorded Year Total	$ 6,678,896
	ORA's Recommendation	**$ 6,678,896**
	Difference (PG&E - ORA)	**$ 4,554,104**

VI. CONCLUSION

In summary, ORA does not recommend any adjustments to Accounts 927 or 928, but proposes the following: For 930, removal of (1) PPP expense for $78,200,000, (2) MCI Exchange of Rights Fees expense for $4,294,080, and (3) the sum of miscellaneous dues, subscriptions, entertainment expense, and the like, or $81,774. For Account 935, ORA proposes a test year estimate of $6,678,896, which is 40.5% less than PG&E's estimate of $11,233,000. This difference is due to ORA's utilization of the Last Recorded Year method.

[8] ORA's recommendation is based on an adjustment all expenses other than the Public Purpose Programs, which amount to $13,085,000.

CHAPTER 11

TOTAL COMPENSATION STUDY

I. INTRODUCTION

For this general rate case, Towers Perrin, an independent consultant, prepared a total compensation study under the collaborative supervision of PG&E and ORA. For this study, total compensation is comprised of cash compensation (base salary plus short-term incentives[1]) and benefits (medical, dental, vision, life insurance, disability, pension and savings plans).[2] The study found that PG&E's aggregate total compensation is 5.17% above market, based on the study results.

PG&E's testimony on total compensation is presented in Exhibit PG&E-1, Chapter 3, "Compensation Policy," Exhibit PG&E-4, Chapter 4, "Performance Incentive Plan," Exhibit PG&E-7, Chapter 9, "Total Compensation Study Results" and Exhibit PG&E-7, Chapter 10, "Total Compensation Study." ORA's recommendations regarding PG&E's Performance Incentive Plan (PIP) are presented in Overland Consulting's Administrative & General Expense and Allocations Report.

II. DISCUSSION/ANALYSIS

Towers Perrin collected and analyzed data on five distinct job categories (Executive, Management Supervisory, Management Non-Supervisory/Technical, Physical, and Clerical). The study data in the report were aged to a common date of October 31, 2000. A summary of the results of the study by job category is shown in Table 11-1:

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[1] Short-term incentives are defined as the target incentive award. At PG&E the target incentive award is 50 percent of the maximum potential payout. Ex. PG&E-7, p. 9-5.

[2] Ex. PG&E-7, p. 9-1.

Table 11-1

PG&E'S POSITION TO MARKET

Executive	97.13%
Management Supervisory	103.42%
Management Non-supervisory/Technical	101.71%
Physical	105.33%
Clerical	113.39%
PG&E's Overall Position to Market	105.17%

The total compensation study performed by Towers Perrin shows that PG&E's overall position to market is now 105.17%, a decrease of 2.06% since its last general rate case where the total compensation study showed PG&E at 107.23% of market.

A. Comparison of PG&E's Competitive Position to Market with other California Energy Companies

Like PG&E, Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Southern California Gas Company (SoCalGas) perform total compensation studies for their respective general rate cases. As shown Table 11-2, PG&E's total compensation relative to market is higher than each of the other major California energy utilities.

Table 11-2

CALIFORNIA ENERGY COMPANY'S COMPETITIVE POSITION TO MARKET

Company	Proceeding	% Above Market
PG&E	A.02-11-017	5.17%
SCE	A.02-05-004	4.3%
SoCalGas	A.02-12-027	2.8%
SDG&E	A.02-12-028	0.5%

B. <u>Acceptable Range Of Market Comparison</u>

In PG&E's last rate case decision, D.00-02-046, the Commission did not make an adjustment based on total compensation. The total compensation study results in that proceeding showed that PG&E was 7.23% above market. The Commission indicated that although its practice had been to adjust the total compensation to no more than 5% in PG&E's previous general rate cases, it was willing to look at a wider range of error around the survey average to determine the maximum departure from the mean that still qualified as the market level.[3]

In A. 94-12-005, PG&E's test year 1996 GRC, the Commission reduced PG&E's request for total compensation from 7.93% to 5%.[4] In A.91-11-036, PG&E's test year 1993 GRC, the Commission reduced PG&E's request for total compensation from 8.5% to 5%.[5]

[3] D.00-02-046, pp. 241-243, *mimeo.*
[4] D.95-12-055 (63 CPUC 2d, p. 633).
[5] D.92-12-057 (47 CPUC 2d, p. 304).

III. CONCLUSIONS

In this proceeding, ORA does not recommend that the Commission adjust PG&E's 2003 revenue requirement based on the finding that PG&E's aggregated total compensation is 5.17% above market levels. ORA intends to monitor PG&E's position relative to the market and other major California utilities and will be prepared to recommend adjustments in the future should PG&E's total compensation deviate significantly from the 5% threshold adopted by the Commission in PG&E's 1993 and 1996 general rate cases, Decisions 92-12-057 and 95-12-055, respectively.

CHAPTER 12

INFORMATION TECHNOLOGY COSTS

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) requests test year 2003 (TY 2003) ratemaking for its information technology costs in its 2003 General Rate Case (GRC) filing. The company sets forth its request in Exhibit PG&E-5, "Information Technology Costs." This chapter presents ORA's analysis of the company's proposal and presents recommendations in response to PG&E-5 costs in Major Work Categories (MWC) 01, 02, 05, 53, 77, and 85 respectively.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, Section III present ORA's analysis of PG&E's request and support for ORA's forecasts and adjustments. Section IV provides ORA's conclusions. Section III presents the results of ORA's analysis of the PG&E request for: (1) Customer Information System (CIS) Replacement Project expense and capital expenditures request; (2) Enterprise Application Integration (EAI) Project expense and capital expenditures request; and (3) Other Information Technology Costs expense and capital expenditures request included in Exhibit PG&E-5. Section IV provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

For CIS expenses, PG&E requests $54,370,000 for TY 2003 while ORA recommends $47,936,000. The reason for the $6,434,000 difference is that ORA uses a weighted average to normalize PG&E's test year (TY) request over the GRC ratemaking period of 2003 – 2006. On a policy basis, ORA believes that the CIS TY 2003 expense level should reflect the expected "steady state" of the 2003-2006 GRC ratemaking period. There are no differences between ORA and PG&E in the

test year forecasts for the other information technology functions reviewed in this chapter.

ORA recommends that PG&E develop and implement standards and procedures for conducting bidding processes for IT projects which will demonstrate that ratepayer funding for the IT projects is just and reasonable.

Table 12-1 presents the differences between ORA's and PG&E's projections of Information Technology costs contained in exhibit PG&E-5.

Table 12-1

INFORMATION TECHNOLOGY COSTS
TEST YEAR 2003
(Dollars in thousands)

	ORA	PG&E	PG&E>ORA	Percent
Costs				
CIS Expenses	47,936	54,370	6,434	11.8%
CIS Capital	0	0	0	0.0%
EAI Expense	6,520	6,520	0	0.0%
EAI Capital	2,500	2,500	0	0.0%
Other IT Expenses	13,545	13,545	0	0.0%
Other IT Capital	55,370	55,370	0	0.0%
Expenses Subtotal	68,001	74,435	6,434	8.6%
Capital Subtotal	57,870	57,870	0	0.0%

III. DISCUSSION/ANALYSIS

A. Customer Information System (CIS) Expenses

PG&E is requesting recovery of forecasted CIS expenses for test year 2003. PG&E estimates that the costs of day-to-day operations and routine maintenance in 2003 to be $54,370,000.[1] PG&E estimates the O&M

[1] PG&E-5, page 3-27.

expenses will decrease to $44,075,000 per year by mid-2004. [2] ORA is making a $6,434,000 adjustment to normalize the CIS operations and routine maintenance cost of $47,936,000 in Test Year 2003.

PG&E based its descriptions and cost estimates on existing CIS activities, and they applied them generally to operating and maintaining CorDaptix. (CorDaptix's role as the supplier of the new CIS will be discussed later), which is the product that will replace PG&E's existing CIS system. CIS operations involve monitoring the daily operating cycle, resolving problems encountered during production, and building a data processing schedule. In addition, there are various on-line applications that require support 24 hours a day, seven days a week.

PG&E defines routine maintenance tasks as program fixes, simple job control changes, routine program changes, simple rate changes and paying software maintenance fees. These include fees for CIS software and software used to support the Legacy systems. Similarly, software maintenance fees for CorDaptix are also part of CIS O&M expenses.

In addition to the historical O&M activities associated with CIS operations, PG&E expects that the implementation of its large, new CIS will not be error-free. Immediately following the installation of complex billing systems, industry experience has shown that, although the system can perform its functions as designed, billing errors, production anomalies, and software bugs, among other things, will occur. All this can happen in spite of the large amount of time and effort the Customer Information System Replacement Project (CISRP) team has devoted to testing the hardware and software systems, simulating data conversion, and simulating production at the expected scale of operation prior to rollout. PG&E states it has taken

[2] PG&E Data Request 181, Question 1.

necessary and prudent steps to minimize problems. But, consistent with industry experience, PG&E expects the number and type of problems will fall within the normal range of "fixes" for an application of the size and complexity of CorDaptix, which is the product that will replace PG&E's old CIS.

PG&E estimates that CorDaptix will be effectively "stabilized" within six months of rollout. Following CorDaptix stabilization, PG&E anticipates a systematic reduction of its CIS staffing to the levels needed to perform routine O&M activities and to make the necessary system enhancements needed to respond to potential future system problems and ongoing regulatory changes. PG&E anticipates it will approach a "steady state" staffing level by mid-2004.

PG&E stated in its application that one of the reasons it was replacing its existing CIS with CorDaptix was to minimize the increase in long-term CIS O&M expenses. ORA believes that this should be a goal of any information technology project. Certainly in the implementation of other technology projects, the ability to reduce future expenses is a reasonable justification for a project.

PG&E requested $54,370,000 (in constant 2000 dollars) for 2003 CIS O&M expenses in its testimony. PG&E estimates the O&M expenses will decrease to $44,075,000 (in constant 2000 dollars) per year by mid-2004. [3] ORA recommends making a $6,434,000 adjustment to normalize the CIS operations and routine maintenance cost of $54,370,000 in TY 2003. ORA calculated the $6,434,000 adjustment using a weighted average for CIS

[3] PG&E Data Request 181, Question 1. $50,000,000 in year 2004 nominal dollars expressed in constant 2000 dollars is $44,075,000.

O&M expenses during the 2003-2006 GRC period. [4] [5] ORA is making this adjustment to normalize the level of funding for the 2003-2006 period. [6] Absent normalization, ratepayers would be providing more funding than needed over the four-year rate case cycle. Therefore, ORA recommends a $6,434,000 adjustment to PG&E's CIS expense request (see Table 12-1).[7]

B. <u>Customer Information System (CIS) Capital Expenditures</u>

PG&E requests $0 in capital expenditures for Customer Information System (CIS) Replacement Project (CISRP) in year 2003.[8] PG&E spent $176 million in CISRP capital expenditures for 2000–2002. ORA does not dispute PG&E's 2003 request for $0 in CISRP capital expenditures (see Table 12-1).

PG&E's old Customer Information System (CIS) was over 35 years old. PG&E contends that even though this system served PG&E's customers

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[4] ORA is recommending a third attrition year (year 2006) that will then result in a 2003-2006 GRC period. Please refer to Chapter 19 for ORA's testimony on Attrition Year 2006.

[5] ORA bases its TY 2003 estimate on the following cost data: (1) $54,370,000 for year 2003; (2) $49,223,000 for year 2004 calculated on the based of a weighted average of $54,370,000 per year for the first half of year 2004 and $44,075,000 per year for the second half of year 2004 (see PG&E Data Request 181, Question 1); (3) $44,075,000 for year 2005; and (4) $44,075,000 for year 2006.

[6] If PG&E's recommendation for a 2003-2005 GRC period is desired, then ORA will recommend $49,233,000 for TY 2003 which will result in a $5,147,000 adjustment to PG&E's CIS O&M expense request.

[7] ORA's recommended CIS O&M Expenses adjustment of $6,434,000 to Major Work Category BJ Expenses will result in an adjustment of $5,855,000 to FERC Account 903 and an adjustment of $579,000 allocated to FERC Account 408 (Payroll Taxes) and FERC Account 926 (Pensions and Benefits). Please refer to Chapter 8 for the assignment of this adjustment to FERC Accounts.

well, it is beyond obsolescence and needs to be replaced. PG&E notes that the costs of operating and maintaining the old CIS is increasing as PG&E has worked to upgrade its CIS to adapt to market changes and evolving customer requirements. Increasing O&M costs, the potential risk of system failure, additional system functionality requirements and recent technology developments were all critical factors in PG&E's decision to replace its old CIS system.

PG&E stated that it planned to complete its CISRP in 2002, when it replaces the old CIS with a new product, CorDaptix. CorDaptix is developed by SPL WorldGroup, Inc. PG&E selected CorDaptix after evaluating other potential vendors. PG&E stated that it believes CorDaptix is the best available product capable of meeting the advanced technical, operational, and functional requirements needed to satisfy PG&E's market and regulatory demands for billing and customer service, now and in the foreseeable future.

PG&E specifies the short-term and long-term benefits to replacing its existing CIS with CorDaptix. In the short-term, PG&E states that the new system will reduce the risk that CIS will fail as a result of using an outdated system extended beyond its functional limits. It will also reduce PG&E's dependency on the few people with the specialized programming knowledge related to its outdated CIS. In the long-run, PG&E believes that CorDaptix will minimize increases in long-term CIS Operations and Maintenance (O&M) expenses, increase PG&E's ability to implement CPUC-mandated billing requirements and changes more quickly, mitigate the risk created by critical CIS development in-house resource constraints, and bring PG&E's CIS up to date with present-day technology.

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[8] PG&E-5, page 2-61.

The requirements for a replacement CIS are unique given PG&E's company size, the complexity of its business, and California's regulatory policies. PG&E notes that its service territory is large and contains a large number and wide variety of customer with different energy needs. The company further justifies this assertion by providing an extensive chronology of California's energy market and regulatory policy changes for the past seven years. The company explains that during this time period, customer and billing system vendors were offering highly customized solutions to meet the needs of energy companies in anticipation of competitive markets. However, due to key technical advances, these vendors began to offer integrated solutions in the later 1990s that required less customization.

The CISRP eventually evolved into three phases: the Integrity Phase, the LCIS/Genesis Phase, and the Integrated CCS Phase. At first, only the Integrity Phase was contemplated in the initial approval of the CISRP. PG&E originally estimated the entire CISRP to cost between $270 and $345 million. As the entire CISRP evolved into three phases, this evolution required PG&E to go back to its Board of Directors in 1998 and 1999 and to its Management Committee in 1999 and 2002 with revised CISRP plans and cost estimates to reflect the necessity to start a new phase of the CISRP or modify the schedule and/or budget of a current phase. The final version of CISRP was approval by the Management Committee on June 11, 2002. The final version of CISRP resulted in a revised total CISRP authorization of $377 million for all three phases and set the Schedule Operating Date at December 2002.

ORA's review of PG&E's $176 million dollars request for capital expenditures is associated with the third phase of CISRP. The third phase was completed during 2000-2002. ORA's review focused on the prudence of

PG&E's managerial decisions that approved the allocation of these expenditures. ORA's review consisted of analyzing the managerial approvals for the CISRP, examining the vendor selection and contracts process, reviewing the hardware and software contracts, and reviewing the overall project management of Phase 3.

On October 20, 1999, PG&E made a request to the Board of Directors for capital expenditures of $130 million for Phase 3. On June 11, 2002, PG&E requested approval of an additional $32.5 million from the Management Committee. PG&E stated that additional funds were need for completion of testing the new CIS for performance, integration with other PG&E systems, and accommodation of additional scope requirement as order by the CPUC. ORA reviewed these requests for approval and finds that they were based on demonstrable events and/or factors justifying the request.

PG&E employed a vendor selection process comprised of evaluating 10 potential vendors for the Phase 3 of CISRP. PG&E's evaluation criteria for each vendor were the proposed solution functionality, costs and technical architecture of the proposed solution, and the qualifications for the vendor. PG&E's ultimate vendor, SPL WorldGroup, Inc. (SPL), was the highest rated vendor according to PG&E's criteria. PG&E selected SPL that had performed the work on Phase 2 of the CISRP. ORA highlights this circumstance because at least one vendor, was essentially equal to SPL as a potential vendor for the Phase 3 construction. SCT Utility Systems was rated essentially equal to SPL. ORA points out that PG&E rated SPL higher than SCT Utility Systems on a weighted basis using its weighting criteria.

ORA recommends that in the future PG&E be required to solicit bids from multiple vendors. This recommendation is supported by the Commission's findings in the last GRC:

Finding of Fact 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.

Conclusion of Law 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.

Conclusion of Law 43. Where there is a significant variance for any IT project's original and revised cost or saving estimates, it is incumbent upon PG&E to demonstrate that ratepayer funding of that project is just and reasonable in of current circumstances.

ORA reviewed the original Software Licensing and Consulting Services Agreement between PG&E and SPL as well as the 13 Change Orders. ORA examination verified that the work requested for SPL was in alignment with PG&E's time and costs estimates stated in its management approval request. So based on ORA's review, the costs are reasonable. In the process of this contract review, ORA also inquired whether there was any managerial or financial relationship between SPL and PG&E or any of its affiliates. ORA concluded that no such relationship exists.

PG&E requests $0 in capital expenditures for Customer Information System (CIS) Replacement Project (CISRP) in year 2003. ORA does not dispute PG&E's 2003 request for $0 in CISRP capital expenditures (see Table 12-1). ORA proposes no adjustments to recorded CIS capital expenditures in the proceeding years. If PG&E utilized additional internal procedures and documentation in its procurement process, it would allow for a better ability of outside parties, including ORA, to verify the reasonableness of capital expenditures in this area or for these complex functional areas and significant expenditures. In that regard, ORA proposes the following procedures to improve the review process specifically for regulatory purposes.

More specifically, ORA recommends that PG&E institute standards and procedures in conducting the bidding process for IT projects that will demonstrate that ratepayer funding for the IT projects is just and reasonable. ORA recommends that PG&E develop project evaluation standards and procedures that accomplish the following objectives:

(1) written evaluation criteria used in determining the best vendor,

(2) obtain bids from multiple vendors, and

(3) retain documentation that shows original and revised cost or saving estimates of the IT project.

C. Enterprise Application Integration (EAI) Project Expense and Capital Additions

For the Enterprise Application Integration (EAI) Project, PG&E requests $2.5 million in capital expenditures and $6,520,000 (in constant 2000 dollars) in expense for 2003. [9] During years 2000-2002, PG&E estimated that $32.1 million in capital expenditures plus $0.3 million in expense was spent on EAI. ORA does not recommend any adjustments to PG&E's TY 2003 EAI expense and capital requests (see Table 12-1).

EAI technology has been widely adopted in many industries to connect disparate applications, facilitate work processes and make possible data transfers within and between companies, suppliers and customers. PG&E states the EAI Project will provide the Company and its customers with flexible data integration architecture along with the integrating hardware and software infrastructure needed to meet today's growing information sharing and application integration requirements.

EAI technology employs a set of software tools and processes that allow different business applications to work together by efficiently routing

[9] PG&E-5, page 6-28 and page 6-31.

data from one application to another using a common set of technological components, transforming data from one format to another, and executing business rules about how work flows from one person/process to another.

PG&E's testimony details its needs for EAI as well as the expected benefits associated with implementing this technology. In terms of its need for EAI, PG&E notes that historically it has integrated its internal computer applications by using a point-to-point (P2P) approach. The P2P approach uses a variety of technologies to link two or more computer applications in a manner that usually requires invasive changes to the computer systems being connected.

In response to the burgeoning number and complexity of interfaces, advances in software and hardware have led to new combinations of technology components specifically designed to handle the links and interfaces more efficiently. The products that provide these components are called "integration brokers" or EAI tools. EAI tools can integrate information more quickly from many sources by providing common enterprise-wide infrastructure, tools and protocols.

PG&E highlights the benefits of EAI as allowing PG&E to respond more quickly and completely to regulatory and business changes by reducing the number of application modifications needed to carry out those changes. Another proposed benefit would be the ability to provide PG&E's customers and suppliers with enhanced access to PG&E information, which enables faster response times. By standardizing the integration tool set and methodology, PG&E contends that the EAI project will enhance the efficiency of PG&E's technical organization. As existing systems and applications have become more difficult to modify and interconnect with technologies, PG&E believes the EAI technology will extend the life of these systems and applications that use older technology.

Overall capital costs for the EAI Project were $2.8 million for 2000, $21.2 million for 2001, and $8.1 million for 2002. The EAI Project expenses were $0.2 million for 2001 and $0.1 million for 2000. PG&E did not submit any expense relating to EAI for 2000.

In addition to the 75 EAI Project interfaces, PG&E is developing additional interfaces that may also be implemented in 2002. In 2003, PG&E expects to develop at least 24 new interfaces. For 2003, PG&E has budgeted $2.5 million in capital and $7.126 million in expense for new functionality and interfaces, operation, maintenance and capital improvements.

PG&E also estimated capital expenditures required to upgrade the EAI production servers to accommodate anticipated increases in functionality and transaction volumes that will occur between installation in 2002 and the next server upgrade that will likely take place in 2005. During this three-year period, it is anticipated that the interfaces installed in 2002 will increase to approximately 130. In addition to all the computer programs and other technical components that will be added to these servers, it is also anticipated that transaction volumes will increase in the same proportion.

PG&E makes the following request for Disaster Recovery functions. Because applications such as the Customer Contact Management System 2 (CCMS2) and the OIS depend on EAI for their integration needs and are critical for PG&E's operations, it is necessary to create a robust disaster recovery system for EAI. By investing the additional $870,000, during 2003, PG&E can ensure that all critical applications that depend upon EAI for their integration needs will be supported in a timely manner in the event of natural disasters or other unforeseen emergencies.

For 2003, PG&E estimated ongoing expenses of $7.1 million. This consists of $5.4 million per year for infrastructure and labor and $1.7 million

per year for license fees.[10] These annual expenses started in 2002 when the EAI Project became operational. The PG&E labor component reflects approximately 28 individuals to support existing interfaces, create approximately 24 new interfaces, and provide infrastructure support and supervision. SeeBeyond, an EAI software provider, for technical support and training, provides the contract labor expense. License and maintenance fees are ongoing costs for various software products that include SeeBeyond, Mercator and Oracle. A contingency of 25 percent for unanticipated software license and maintenance fees is included.

ORA has reviewed PG&E's testimony and workpapers supporting its EAI Project. ORA also has had informational meetings with PG&E EAI witnesses and members of the EAI project team. ORA does not take issue with PG&E stated needs for either the EAI Project or the potent benefits PG&E cites for this project.

ORA does have concerns regarding the vendor selection process that PG&E employed to select the Mercator and SeeBeyond solutions. In 1999 PG&E began its research into EAI technology. This research focused on technology features, product scalability and vendor market presence. PG&E also states that this research was directed towards finding a solution to complement the "batch" processes that would be necessary to support the implementation of its CISRP solution, CorDaptix. PG&E was also looking for a vendor that could meet CorDaptix's time schedule. After more than a year of research, PG&E selected Mercator as the EAI solution vendor.

As PG&E was finalizing its Mercator decision, PG&E began searching for additional EAI software functionality. PG&E notes that it

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[10] The year 2003 cost of $7.1 million is in 2003 nominal dollars and this amount is equal to $6,520,000 in constant 2000 dollars

attended industry conferences in summer of 2000 and in October 2000. Potential vendors for this additional functionality were Informatica, SagaSoft, MQ Series, Vitira, Tibco and STC/SeeBeyond. Mercator, the selected vendor from PG&E's first EAI research, was not even considered. Each vendor went through a selection process that included assessment of product functionality, reference check, pricing consideration, and a demonstration and evaluation process. This process resulted in STC/SeeBeyond being selected by PG&E for the additional EAI software functionality. The selection was made in February 2001, only six months after PG&E chose Mercator.

ORA questions why PG&E did not revise its initial requirements for an EAI vendor to include the additional functionality. PG&E emphasizes the batch functionality of Mercator in supporting CorDaptix as reasoning for it selections. However, PG&E states that SeeBeyond could handle small volume, simple complexity batch interactions. Perhaps if PG&E had expanded its requirements for an EAI solution prior to selecting Mercator, SeeBeyond, or another vendor, PG&E could have developed a more robust solution to better handle both batched and real-time interactions.

Another rationale that PG&E states in support of its Mercator decision in September 2001 is that the EAI vendor needed to meet that CorDaptix timeline. At that time, PG&E had informed its Board of Directors that its expected completion date for CorDaptix was June 2002 (See Exhibit 5, Page 2B-14). Ironically, SeeBeyond was implemented in June 2002 while the Mercator implementation was delayed until November 2002 coinciding with CorDaptix's installation. While, PG&E attributes most of CorDaptix's delay from June to November to the Governor's 2002 20/20 Rebate Program, PG&E does admit that CorDaptix was not ready in June 2002 due to developmental issues apart from the 20/20 Program as noted in A.02-09-

005. After reviewing the above circumstances, ORA does not have any issue with the expenditures.

D. Other Information Technology Expenses and Capital Additions

PG&E requests that the Commission adopt its 2003 forecast of $55.37 million for capital expenditures to replace obsolete equipment and upgrade critical infrastructure and $13,545,000 (in constant 2000 dollars) of electric and gas distribution O&M expenses for IT activities that support maintenance of the mainframe computer and the implementation of the Utility Operations Customer Care Project.[11] PG&E states in Exhibit PG&E-5 that its capital expenditure amounts for its IT Programs were $47.99 million for 2001, and estimated at $62.23 million for 2002, and $55.37 million for 2003 to replace obsolete equipment and upgrade critical infrastructure needed to improve the efficiency of operations.

ORA reviewed PG&E's testimony and workpapers and issued data requests on PG&E's process for determining and prioritizing the projects included in the Test Year 2003 GRC. PG&E requested expenditures in Major Work Categories (MWC) 01, 02, 05, 53, 77, and 85. MWC 01 includes IT Desktop Computers, MWC 02 includes IT Voice Communication, MWC 05 includes tools and equipment needed for maintenance of telecommunication and computer systems, MWC 53 includes IT Applications, MWC 77 includes hardware for the CIS after the CIS Replacement Project is concluded, and MWC 85 includes IT Infrastructure.

PG&E's Other IT cost testimony only addresses the O&M expenses and capital projects within the MWCs managed by Information System Technology Services (ISTS) department. While the ISTS department

[11] PG&E-5, page 8-25 and page 8-28.

provides IT services for the entire Company, the 2003 O&M expense and capital expenditures presented in this testimony are only for the Company's distribution function.

PG&E justifies its expense and capital requests on the basis that such expenditures allow the Company to maximizes the life of technology to effectively support the operations of the business using proven technologies and efficiently manage both the expense and capital dollars spent on IT assets through the use of centralized program management.

ORA accepts PG&E's Test Year 2003 requests for $55.37 million in capital expenditures and $13,545,000 (in constant 2000 dollars) in expense expenditures for Other Information Technology Costs (see Table 12-1).

IV. CONCLUSION

For Customer Information Systems (CIS) expenses expenditures, PG&E requests $54,370,000 for TY 2003 while ORA recommends $47,936,000. The reason for the $6,434,000 difference is that ORA uses a weighted average to normalize PG&E's Test Year request over the GRC ratemaking period of 2003 – 2006. ORA believes that the CIS TY 2003 expense level should reflect the expected steady state of the 2003-2006 GRC ratemaking period. ORA accepts PG&E's requests for CIS capital expenditures, EAI Project expenditures, or Other Information Technology Costs expenditures included in Exhibit PG&E-5.

ORA recommends PG&E develop and implement standards and procedures in conducting bidding processes for IT projects which will assist in demonstrating that ratepayer funding for the IT projects is just and reasonable.

CHAPTER 13
TAXES

I. INTRODUCTION

This chapter presents ORA's recommendations relating to tax expense and responds to PG&E's request for tax related revenue requirements contained in PG&E Exhibit 6, Distribution Results of Operations, Chapter 7 Payroll Taxes, Chapter 11, Income and Property Taxes, and PG&E Exhibit 10, Retained Generation Results of Operations-Revised, Chapter 9, Payroll Taxes, and Chapter 12, Income and Property Taxes. PG&E is requesting cost recovery for test year estimated income and other taxes.

Tax expense is the composite of projected taxable income streams, book expenses, special tax deductions, and tax credits, calculated within the combined contexts of "real world" tax law, and "regulatory world" tax policy. Tax expense also includes taxes which are not a function of income streams, but of the payment of employee compensation, and the ownership of property.

Regulated tax expense is comprised of the following items: (1) federal income taxes (FIT), California Corporate Franchise Taxes (CCFT), (2) payroll taxes, and (3) ad valorem, or property taxes.

Section II presents ORA's Summary and Recommendations. Section III discusses specific tax issues analyzed by ORA. Section IV provides concluding comments. Certain aspects of ORA's income tax review were performed by a contractor, Overland Consulting. The results of that review are described in Chapter 12 of Overland's Administrative and General Expense And Allocations Report (the Overland Report).

II. SUMMARY/RECOMMENDATIONS

ORA recommends that test year tax expense be computed using the following parameters and assumptions:

1. For federal income tax purposes, the corporate tax rate of 35% should be used to compute FIT. This rate should be used for the net-to gross multiplier. PG&E appropriately used this rate.

2. For state income tax purposes, the corporate tax rate of 8.84% should be used to compute CCFT. This rate should be used in computing the net-to-gross multiplier. PG&E appropriately used this rate.

3. PG&E's most recently approved weighted cost of long-term debt factor of 3.50% should be used in calculating the interest expense deduction for FIT and CCFT purposes.

4. PG&E did not substantiate the nature of certain operating expense (negative) adjustments included in the tax deduction tables for electric, gas and URG. The adjustments have the effect of increasing cost of service for income taxes. ORA recommends disallowing (negative) tax operating adjustments of $26.9 million in the electric department, $16.0 million in the gas department and $6.5 million in URG.

5. Payroll tax rates and wage bases forecasted by PG&E were found to be reasonable and should be applied in estimating payroll tax expense. Any differences between ORA and PG&E are due to differences in the test year estimate for labor expense.

6. Property tax expense and underlying forecasted valuations were found to be reasonable and should be applied in estimating property taxes. Any differences between PG&E and ORA are due to differences in the test year estimated plant additions.

7. All federal and state tax timing differences should be flowed through to the ratepayer to the extent allowed by Commission policy, and federal and state tax law.

8. ORA recommends that the tax effects stemming from the Job Creation and Worker Assistance Act of 2002 be included in the test year tax estimates, including deferred taxes. PG&E included the new tax law in its deferred tax estimates.

9. PG&E's proposed three-year amortization period for the remaining balance of the fossil and hydro power plant Tax Regulatory Asset is arbitrary and inconsistent with CPUC income tax policy. Deferred income taxes should be reduced by $23.4 million to reflect a 20-year amortization period. The support for this adjustment is contained in Chapter 12 of the Overland Report.

10. PG&E failed to include a deduction for capitalized A&G overheads in its 2003 current income tax calculations. PG&E's 2003 current income tax expense forecast should be reduced by $9.7 million to reflect ORA's forecast of the capitalized A&G overheads deduction. The support for this adjustment is contained in Chapter 11 of the Overland Report.

11. ORA recommends that any changes in federal and state tax law made before the close of the record in this proceeding be incorporated into the tax estimates for the test year, after review of the new law by ORA.

III. DISCUSSION/ANALYSIS

The following section provides a brief background of regulated tax expense and a discussion of certain specific tax deductions, credits and other tax policy issues applied in determining taxable income for ratemaking purposes, as well as other issues affecting revenue requirements for taxes other than income. Unless otherwise noted, all discussions apply equally to both federal and state income tax expense.

A. <u>Basis for Regulated Tax Expense</u>

While the mathematical model used to calculate tax expense is seemingly unequivocal, the underlying accounting conventions,

applicable tax rates, and the determination of what constitutes allowable deductions is a function of current federal and state tax law, including new laws expected to affect the test year, regulatory tax policy as determined by numerous Commission decisions, and ORA recommended tax and adopted tax policy. Much of existing Commission tax policy was established in Order Instituting Investigation 24 (OII 24), D.84-05-036, 15 CPUC 2d 42 (1984). Numerous subsequent decisions adopted a variety of changes in ratemaking tax policy in order to comply with changes in federal and state tax laws.

Another way to articulate ORA's goal is that the test year's income tax expense estimate should reflect, to the extent possible, the current deduction of expenses in which there is a book/tax timing difference. In D.84-05-036, the Commission stated, "[f]or the present, we will continue our current policy regarding flow-through treatment of timing differences consistent with applicable tax law."[1] ORA recommends that the Commission continue to adopt policies which result in the test year tax estimate reflecting, to the extent possible,[2] the flow-through of forecasted expenditures. It is important to note that in most cases, it is the regulated utility's *parent corporation*, which actually pays the income taxes of the regulated utility as part of a consolidated or combined income tax return. Therefore, it is ORA's position that the regulatory goal of estimating tax expense is to mirror, to the extent

[1]See D.84-05-036, discussion at Section I, pp. 32-33a. The Commission refused to adopt additional normalization requirements beyond those required for depreciation.
[2]ORA's recommended treatment for certain tax deductions and benefits is limited by Income Tax Normalization requirements of the Internal Revenue Code, as well as tax policy established in D.84-05-036. For example, currently, disallowed expenses cannot be used as tax deductions.

permissible by tax law, the actual tax liability of the regulated unit payable to the parent corporation.

B. <u>Income Taxes, Deductions and Credits</u>

1. Tax Normalization

Normalization is a ratemaking concept, which aims to adjust a utility's operating expenses in the test year by eliminating abnormal, non-annual events that are known and certain to change in a regularly recurring manner. For example, accelerated depreciation is a tax expense, which is normalized over the life of an asset when computing ratemaking tax expense. It is known and certain that toward the end of the life of an asset, straight-line (book) depreciation will exceed accelerated tax depreciation. However, at the conclusion of the asset's life, the total depreciation charges under both book and tax methods will be equivalent.

Income tax normalization permits a utility to include as its current ratemaking expense an amount of income tax expense that is higher than what the utility will actually pay. This is based on the theory that the taxes saved by the accelerated depreciation (taken on the real world tax returns) are merely deferred. Utilities generally use accelerated methods of depreciation on their real world tax returns, while using the straight-line method for book purposes. IRS rules require that utilities use book depreciation rates on all plant purchased or constructed after 1980 when computing regulated tax expense. To mitigate the effect of normalization, the tax effect of the differences between accelerated and straight-line depreciation is booked to a deferred tax reserve. The deferred taxes are used to reduce ratebase.

Because of current tax law, utilities are required to adopt normalization for depreciation on assets placed in service after 1980. However there is no federal tax requirement that normalization be used for other tax timing differences. In fact, it is the policy of this Commission to flow through non-plant tax timing differences.

2. Tax Depreciation

For FIT purposes, tax depreciation for all post 1980 plant has been normalized using book lives and rates. For 1980 and prior years' plant, the appropriate accelerated depreciation has been flowed through. For CCFT purposes, tax depreciation has been flowed-through in estimating CCFT taxable income. Tax depreciation for ratemaking purposes does not include depreciation on plant costs disallowed in previous rate cases.

3. Job Creation and Worker Assistance Act of 2002

The Job Creation and Worker Assistance Act of 2002 includes certain tax incentives, which may affect tax depreciation and deferred taxes in the test year. In short, the new tax law provides for bonus depreciation in the first year of service equal to 30% of the depreciable tax basis of qualified assets acquired between September 11, 2001 through September 10, 2004.

The new tax law primarily affects deferred taxes because depreciation deductions under the new law must be normalized for ratemaking purposes. However, deferred taxes, which lower ratebase, have been adjusted by ORA and PG&E to reflect the estimated tax benefits PG&E will receive as a result of application of the tax law.

4. Software Expenditures

There are two different types of software related expenditures: internally developed software, and purchased software. A portion of internally developed software may be deducted currently as research and development costs while a portion must be capitalized.

PG&E flowed through the deductible portion of internally developed software costs forecasted in the 2003 test year. Currently deductible costs lower estimated regulated taxable income in the test year, thereby lowering ratemaking income tax expense. ORA concurs with how PG&E has treated software costs for tax purposes.

5. Interest Expense

For FIT purposes, interest expense was derived by applying the weighted average cost of long-term debt to ORA's estimated rate base. In its application, PG&E used a weighted long-term debt cost factor of 3.35% to estimate its interest expense deduction. However, ORA recommends that the weighted long term debt cost factor of 3.50% be used because this factor is based upon PG&E's most recently approved cost of capital for the test year 2003 (D.02-11-027, dated November 7, 2002). Any other differences in the total amount of interest expense deductible for regulated income tax purposes are, therefore, the result of differing rate base estimates between PG&E and ORA.

The unamortized deferred investment tax credit (ITC, discussed below) balance was deducted from rate base for this calculation because PG&E is an option one company (see discussion for ITC). "Interest synchronization" which normally results in a higher interest deduction, and therefore, a lower regulated FIT expense, is not applicable because of how PG&E treats unamortized ITC (option one). PG&E also used this

approach in its results of operations. For CCFT purposes, the unamortized ITC was deducted from rate base by ORA and PG&E before applying the same debt cost factor. For CCFT purposes, it does not matter whether PG&E is an option one or two company because there is no ITC available for CCFT purposes.

6. FIT Deduction for Prior Year's CCFT

The amount of CCFT allowed as a deduction for FIT purposes by the IRS is not the current year's CCFT. The amount allowed on the FIT return is the prior year's CCFT liability. This creates a timing difference between when the payment of the CCFT is made and when it is allowed as a tax deduction.

This issue was addressed in Phase II of one of PG&E's prior general rates cases; A.85-12-050 (I.86-11-019). D.89-11-058, issued on November 22, 1989, requires that for ratemaking purposes, the prior year Commission *adopted* CCFT number be used as the deduction for CCFT taxes in arriving at FIT taxable income. PG&E used the prior year's (2002) estimated CCFT number as a 2003 deduction for FIT purposes. Although there is no 2002 *adopted* estimate for CCFT, ORA concurs with PG&E on this point because it yields a reasonable result. Therefore, the prior year's CCFT estimate (2002) was used as a deduction in arriving at the test year's estimated FIT.

7. Cost of Removal

The cost of removal deduction is estimated on the basis of forecasted plant retirements for the test year. Removal costs are incurred when plant is physically removed from service. Removal costs are deductible for tax purposes when incurred. Under the normalization requirements of the tax code, estimated removal costs associated with

plant vintage years after 1980 are not currently deductible. However, a cost of removal deduction is still available for 1980 and prior property for FIT purposes, and for all vintage years for purposes of calculating CCFT taxable income. For this reason, the deductible CCFT estimate is larger than the FIT deduction. Current deductions for cost of removal are reflected in the FIT and CCFT tables.

8. Repair Allowance

The cost of plant construction is capitalized for book purposes. However, a percentage of these capitalized costs are deductible for income tax purposes as repairs (repair allowance). A repair allowance deduction is generally available for 1980 and prior years' vintage assets for FIT purposes, and on all vintages for CCFT purposes.

9. Operating Expense Adjustments

PG&E included certain negative adjustments in the tax deduction tables for each of gas, electric and URG segments. The negative adjustments have the effect of increasing taxable income, thereby increasing income tax expense. Operating expense adjustments in the following amounts were included in the schedule M tax adjustment tables: (1) electric department, $26,967,000, (2) gas $16,040,000 and (3) URG, $6,567,000. The largest adjustment included in each of these is attributable to an adjustment for "disallowed motor vehicle depreciation." PG&E did not substantiate the nature of this depreciation adjustment, or why it was subtracted out of the deductions for depreciation (operating expenses) related to motor vehicles. Therefore, ORA recommends disallowing these tax operating adjustments. In PG&E's previous general rate case, the tax computations included diminutive amounts for operating expense adjustments. However, the operating expense

adjustments included in this general rate case are substantially larger and inconsistent with how PG&E treated operating expense adjustments in the previous rate case. [3]

10. Investment Tax Credit (ITC)

Under current federal tax law, ITC must be amortized over the life of the underlying plant when estimating regulated federal income tax expense. Generally, this method of normalizing ITC applies to plant placed in service after 1980. Public utility corporations have two normalization methods to choose from when electing a method to amortize ITC for regulated tax purposes. Under option one, the tax benefits of ITC are flowed through to ratepayers by deducting deferred ITC from rate base; as each year passes, the deferred ITC balance decreases, thereby ratably restoring rate base over the book life of the plant which generated it. Under option two, the tax benefits of ITC are ratably flowed through as a direct reduction of estimated FIT. PG&E uses option one. This is an important distinction because it affects how PG&E and ORA computed the interest expense deduction for FIT purposes (see discussion for Interest Expense).

C. <u>Payroll, Property and Other Taxes</u>

1. Payroll Taxes

Payroll taxes and their respective rates and wage bases are: Federal Insurance Contribution Act (FICA) 6.20%, $89,700 wage base, Medicare 1.45%, no wage base, Federal Unemployment Insurance (FUI)

[3] For this rate case, ORA attempted to input the proposed adjustment(s) in the results of operations model for income taxes but the model was unable to calculate the correct results.

.80%, $7,000 wage base, and State Unemployment Insurance (SUI) 2.100%, $7,000 wage base. ORA concurs with these rates and wage bases.

2. Property Taxes

ORA's recommended tax deduction for property taxes is based upon the test year estimated full accrual of ad valorem taxes due on property held as of the lien date. This amount is higher than the property taxes estimated for book purposes because for book purposes, only the estimated actual calendar year payments are considered. The difference between the full year accrual and the book amount is the lien date adjustment which has been flowed through as a current tax deduction for estimating test year taxable income. This is consistent with PG&E's ability to deduct for actual FIT and CCFT purposes the full year lien date accrual amount.

ORA analyzed PG&E's method of estimating ad valorem taxes for the test year and found its methodology reasonable. The differences between ORA's property tax estimate and PG&E's are solely due to differences in plant estimates.

IV. CONCLUSION

All tax benefits should be flowed through to the ratepayer to the extent possible under the Internal Revenue Code. Negative operating expense adjustments included in the income tax tables should be substantiated with applicable tax law or other substantive data which correlates the adjustments to other portions of the results of operations model. With the exception of the two issues developed in the Overland Report, there are no other methodological

differences between ORA and PG&E for computing income taxes, and taxes other than income.

CHAPTER 14

PLANT: ELECTRIC DISTRIBUTION

I. INTRODUCTION

This chapter addresses the forecast of electric distribution plant expenditures and additions for the 2003 test year[1]. Pacific Gas and Electric Company (PG&E) sets forth its request for 2001, 2002 and 2003 capital expenditures and additions in Exhibit PG&E-2, "Distribution Operation Costs" and in Exhibit PG&E-6, Chapter 8, "Electric, Gas and Common Plant"[2]. This chapter presents ORA's analysis of the company's proposal and presents recommendations in response to PG&E-2 and PG&E-6, Chapter 8.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations. Section III covers the conversion of ORA's recommended adjustments to capital additions, and Section IV presents ORA's analysis of PG&E's request and support for ORA's forecasts and adjustments to Major Work Categories 16, 30, 07, and 56. Section V contains ORA's analysis and recommendations with respect to PG&E's planning, budgeting and forecasting methodologies and Section VI provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

PG&E is asking the Commission to adopt its forecast for electric distribution capital expenditures of $621 million for 2002 and $653 million for 2003. These expenditures form the basis of PG&E's estimates for 2002 and 2003

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[1] Plant will be referred to as "capital" throughout the discussion in this chapter.

[2] 2001 capital expenditures additions are recorded amounts and were accepted by ORA. For the purposes of calculating rate base, PG&E starts at EOY 2001.

capital additions[3]. PG&E forecasts capital additions of $659 million for the year 2002 and $668 million for the 2003 test year.[4] ORA recommends that the Commission adopt PG&E's 2002 recorded capital expenditures of $630 million[5] and capital additions of $540 million for electric distribution plant.[6] For 2003, ORA recommends adjustments to PG&E's capital expenditure and capital additions forecast, resulting in 2003 capital expenditures equal to $596 million and capital additions equal to $632 million. This is equivalent to an adjustment of $56.4 million for capital expenditures and $36 million for capital additions. ORA's adjustments are based on a review and analysis of specific electric distribution capital MWCs. ORA reviewed historical spending for specific capital areas and issued discovery regarding PG&E's forecasting and budgeting process.

The individual program capital expenditure forecasts are presented by various PG&E witnesses in Exhibit PG&E-2. The capital expenditure forecasts are the inputs to PG&E's Results of Operation (RO) model. The model calculates capital additions for 2002 and 2003, based on the capital expenditure inputs, 2001 Construction Work In Progress (CWIP) amounts, estimated operative dates for projects and groups of projects and estimated retirements for 2002 and 2003. The results of those calculations are presented in Exhibit PG&E-6. ORA reviewed the individual program capital expenditure forecasts, the estimated operative dates for

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[3] PG&E's capital forecast is based on expenditures for specific asset programs rather than a forecast of capital additions to be booked to plant for the test year. PG&E's RO model converts these capital expenditures to capital additions, calculates the net amount that will be added to plant for the test year by removing estimated retirements, and calculates the WAVG additions. The net additions and weighted average additions (WAVG) are added to the 2001 end-of-year (EOY) plant balance to determine the dollar amount of plant that will be used as the foundation for PG&E's return on investment.

[4] PG&E-6, p. 8-18.

[5] E-CIW-239, Question 2, Attachment 0239-02-1REV.

[6] PG&E's 2002 recorded capital additions were provided to ORA in Data Request Response E-CIW-265.

some of PG&E's larger projects, PG&E's estimate for retirements, and PG&E's weighted average (WAVG) percentage. ORA used an updated version of PG&E's RO Model, that ORA understands was changed to include 2002 recorded data and also included an adjustment to electric distribution plant of $31 million to eliminate PG&E's double-counting of Cost of Removal (COR). Therefore, ORA's starting point for developing PG&E's rate base is End-of-Year 2002.

Table 14-1 presents the differences between ORA's and PG&E's 2002 plant additions, 2002 retirements, 2002 end of year balances, 2003 forecast additions and 2003 WAVG additions.

Table 14-1

ELECTRIC DISTRIBUTION PLANT
FUNCTIONAL PLANT[7] SUMMARY
(In Thousands of Nominal Dollars)

PG&E's Forecast						
2001 EOY Balance	2002 Forecast Additions	2002 Forecast Retmnts.	2002 EOY Balance	2003 Forecast Additions	2003 Forecast Rtmnts.	2003 WAVG Additions
12,261,541[8]	659,014[9]	139,606[10]	12,780,949	668,183[11]	75,740[12]	317,265[13]
ORA's Recommendation						
2001 EOY Balance	2002 Recorded Adds.	2002 Recorded Retmnts.	2002 EOY Balance	2003 Forecast Additions	2003 Forecast Rtmnts.	2003 WAVG Additions
12,261,541	540,307[14]	46,789[15]	12,755,059	632,165	74,057	268,425

Table 14-2 presents the differences between ORA's and PG&E 's Weighted Average Plant-In-Service balances for the 2003 test year.

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[7] Functional Plant includes Electric Distribution Electric Transactions Administration.

[8] PG&E-8, Workpaper 8-23

[9] PG&E-8, Workpaper 8-5.

[10] PG&E-8, Workpaper 8-288.

[11] PG&E-8, Workpaper 8-5.

[12] PG&E-8, Workpaper 8-395

[13] PG&E-8, Workpaper 8-19.

[14] E-CIW-265, Attachment ORA_0265-01-2.

[15] C-CIW-143, Attachment ORA_0143-01-1RevSupp.

Table 14-2

WEIGHTED AVERAGE PLANT-IN-SERVICE BALANCES[16]
TEST YEAR 2003
(In Thousands of Nominal Dollars)

	ORA Recommended	PG&E[17] Recommended	Difference PG&E-ORA
Functional	12,987,428	13,138,721	151,293
Common	1,361,244	1,397,777	36,533
General	97,088	95,816	-1,272
Intangible	8,656	8,656	0
TOTAL	14,454,416	14,640,970	186,554

Table 14-3 presents the differences between ORA's and PG&E's electric distribution capital expenditures and additions for the 2003 test year.

Table 14-3

ELECTRIC PLANT CAPITAL EXPENDITURES AND ADDITIONS
TEST YEAR 2003
(In Thousands Of Nominal Dollars)

	ORA	PG&E	PG&E>ORA	Percent
Expenditures	596,234	652,655	56,421	8.6%
Additions	632,165	668,183	36,018	5.4%

In addition to ORA's proposal for specific adjustments to PG&E's forecast, ORA recommends that the Commission require PG&E to institute changes to its planning, budgeting and forecasting methodology to provide improved information regarding PG&E's forecasting approach and to facilitate review of PG&E's forecast for regulatory purposes in the next rate case. These recommendations are:

- Provide a specific and detailed accounting of the decision-making process for prioritizing and re-prioritizing spending,
- Institute appropriate changes to allow for a comparison of forecasts, job estimates, and actual dollars spent, and

[16] Electric Plant includes Common, General and Intangible Capital Plant for Energy Transactions Administration.

[17] Workpaper 8-450.

- Institute a method for tracking changes in the functional accounting system.

III. 2002 AND 2003 CAPITAL ADDITIONS

PG&E's forecast is based on monthly capital expenditures for 2002 and the 2003 test year. The monthly expenditures are presented as projects (or groups of projects), by MWC, UCC code and Functional Plant Numbers. The monthly forecasts include all financial costs, including capitalized Administrative and General (A&G), Allownce For Funds Used During Construction (AFUDC),[18] and Cost of Removal (COR). These monthly expenditures are the input to PG&E's RO model. The model uses the expenditure data and the operative date for the project (or groups of projects) to calculate monthly and annual capital additions and weighted average annual capital additions for 2002 and 2003.

The monthly capital expenditures and any Construction Work In Progress (CWIP) associated with the specific projects listed in the model are added together to determine the monthly and annual capital additions for each project (or group of projects).

PG&E defines three types of retirements that are applied to the capital additions calculation. Vintage Retirements and Major Retirements are specifically identified and removed from the plant balance for each associated asset type. Normal retirements are estimated as a percentage of gross additions over a 5-year period of time. For Electric Distribution Plant, PG&E estimates normal retirements by applying 8.63% to gross capital additions. The 8.63% factor is equal to the average percentage of retirements to gross additions for the years 1997 through 2001. For 2002, the percentage of recorded normal retirements to recorded gross additions is equal to 8.6 percent.[19] PG&E's estimates for retirements appear reasonable.

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[18] PG&E-6, p.8-6 and 8-7.

[19] C-CIW-143, Question 2, revised and supplemented.

PG&E's WAVG plant calculations are embedded in the RO Model. For 2003, the model applies a weighting of 44%. ORA compared the weighting used in the model to PG&E's historical weighting percentage and found the model's weighting consistent with actual WAVG percentages for the years 1997-2002.[20]

Although PG&E's forecasts are meant to represent the total financial costs for each capital program, the company did not identify the different types of costs or the amounts of these costs that are included in the total. When ORA asked PG&E to explain the method used to estimate capitalized expenses and AFUDC for the 2002 and 2003 forecasts, PG&E responded that it did not include specific estimates for these items.[21] This meant that forecasts could not be adjusted to track the adjustments made to Administrative and General (A&G) Expenses. Therefore, ORA's capital forecasts were not adjusted for any changes to PG&E's overall A&G expenses and associated changes to capitalized A&G.

PG&E did not indicate in either its testimony, workpapers or discovery responses, that COR is included in its the monthly capital expenditure forecast. During the week of March 3, 2003, ORA found out that these costs were treated as expenditures and capital additions as well as an offset to depreciation reserve. For 2002, the COR associated with electric distribution plant was $47 million.[22] Normally, COR are booked as an offset to depreciation reserve and are not included in capital additions. However, PG&E's electric distribution capital expenditure and capital addition forecast included COR, resulting in an additional $47 million being added to plant as a capital addition and as an offset to depreciation reserve. This means that PG&E has double-counted these costs, resulting in an over-statement of

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[20] The updated RO model calculateds WAVG electric distribution plant at around 51%. This is because of the 2002 CWIP amounts that PG&E included in the update. ORA reduced the total amount of CWIP and made adjustments to the model to reduce the weighting percentage.

[21] C-CIW-148, Question 1.

[22] E-CIW-328, Attachment ORA_0328-01-1.

end-of-year plant balances. For the 2003 test year, PG&E estimates electric distribution COR equal to $31 million.[23]

On March 26, 2003, PG&E provided ORA with a revised RO model that allegedly incorporates 2002 recorded data and adjusts the 2003 capital expenditures and additions to exclude PG&E's 2003 forecasted COR of $31 million.[24]

For future rate cases, PG&E should identify the type of cost and the amount of each type of cost that makes up the capital expenditure and capital addition forecast used to develop PG&E's rate base request.

ORA made adjustments to the capital expenditure portion of the RO model to incorporate the changes recommended in this chapter for the 2003 test year. Changes were also made to some operative dates for projects that were discovered to be behind schedule or deferred.[25] Though ORA agrees that some amount of CWIP should be added to plant in 2003, PG&E's amount seems excessive based on historical CWIP balances. ORA adjusted the 2002 CWIP amount for electric distribution plant and included $68.4 million in additional capital additions for the 2003 test year.

IV. 2003 CAPITAL EXPENDITURES

PG&E 's electric distribution capital expenditure forecast for 2003 is $653 million[26] and includes spending for programs related to maintenance, customer requested construction, substation asset management, pole asset management,

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[23] E-CIW-328, attachment ORA_0328-04-1.

[24] The bulk of the adjustments were made to EDP, Electric Distribution Plant. Smaller adjustments were made to common plant accounts (see Chapter 15 of this report), EGP Electric General, and ETP, Electric Transmission. ORA did not do a thorough analysis to determine if the model accurately reflects PG&E's 2002 recorded cost. For the purpose of this testimony, ORA accepts PG&E's updates to include 2002 recorded data.

[25] ORA changed the operative date for 2 capacity projects, Project #5709441and Project #5709489. See PG&E's responses to E-CIW-84, Question 2 and E-CIW-116, Question 5. ORA changed the operative date for one underground cable project, project #5711798 from 11/5/02 to 6/30/03 to reflect the fact that the project would not be completed until Summer of 2003.

[26] PG&E-2, p.1-1.

underground asset management, capacity, dependability and meter purchases. PG&E claims that these expenditures are needed if PG&E is expected to provide its customers with adequate service as defined by the Commission in D.00-02-046.[27] Exhibit PG&E-2 is comprised of individual chapters for each of PG&E's asset programs. Each chapter includes a description of the capital expenditure request for each specific program.

ORA's electric distribution capital expenditure forecast for 2003 is $596 million. ORA's forecast is $56.4 million less than PG&E's forecast of $653 million. ORA's adjustments do not apply to all of PG&E's programs or individual MWCs contained in those programs. The fact that ORA is not proposing specific adjustments to some of the MWCs should not be interpreted as support for PG&E's forecast for those MWCs. Rather, ORA prioritized its review by focusing on those programs that contained the largest dollar amount in forecast expenditures for the test year, or that varied from historical spending. Table 14-4 compares ORA's and PG&E's capital expenditure forecast for all MWCs.

[27] Ibid.

Table 14-4

COMPARISON OF ELECTRIC PLANT EXPENDITURES
TEST YEAR 2003
(Nominal Dollars in Thousands)

MWC	Description	ORA	PG&E	PG&E> ORA	Percent
MWC 06	Dist.Line&Equip. Cap.	30,881	30,881	0	0%
MWC 07	Pole Replacements	79,500	90,908	11,408	12.5%
MWC 08	Mitigate Rec. Outages	7,090	7,090	0	0%
MWC 09	Automation	4,070	4,070	0	0%
MWC 10	Work Req. by Others	31,001	31,001	0	0%
MWC 16	Customer Connection	187,722	212.625	24,903	29.3%
MWC 17	Emer. Resp. Maint.	70,436	70,436	0	0%
MWC 25	Meter Purch./Maint.	13,371	13,371	0	0%
MWC 30	Undergrounding 20A	38,890	55,000	16,110	29.3%
MWC 46	Substation Capacity	20,435	20,435	0	0%
MWC 48	Repl. Sub. Equipment	20,435	20,435	0	0%
MWC 49	Mainline Prot. & Reb.	5,400	5,400	0	0%
MWC 54	Repl. Sub. Trans.	18,300	18,300	0	0%
MWC 56	Cable Replacement	5,000	9,000	4,000	44.4%
MWC 57	Preventive Maint.	57,032	57,032	0	0%
MWC 58	Repl. Sub.-Safety	7,501	7,501	0	0%
MWC 59	Repl. Sub.-Emergency	6,500	6,500	0	0%
TOTAL	All Electric Dist.	596,234	652,655	56,421	8.6%

Addressed below are the programs and MWCs for which ORA is proposing an adjustment for the 2003 test year.

A. Customer Requested Construction

PG&E's proposed capital expenditures for Customer Requested Construction is presented in Exhibit PG&E-2, Chapter 3. This asset program includes capital for new customer connections (MWC 16), work requested by others (WRO, MWC 10), and undergrounding (MWC 30). ORA proposes an adjustment of $25 million to PG&E's forecast for MWC 16 and an adjustment of $16 million for MWC 30. Table 14-5 presents the differences between PG&E's and ORA's forecast for MWCs 16 and 30.

Table 14-5

CUSTOMER REQUESTED CONSTRUCTION
CAPITAL EXPENDITURES
TEST YEAR 2003
(Dollars in thousands)

	ORA	PG&E	PG&E>ORA	Percent
MWC 16	187,722	212,625	24,903	11.7%
MWC 30	38,890	55,000	16,110	29.3%

PG&E states that if the Commission does not adopt PG&E's capital expenditure forecast for customer connection work, PG&E would support the establishment of a two-way balancing account.[28] ORA opposes the use of balancing account treatment for several reasons. First, the variance between PG&E and ORA's 2003 capital expenditure forecast is less than 12%. Compared to PG&E's overall capital expenditure request of $653 million, the difference between ORA and PG&E's forecast is only 4% of PG&E's entire ask. The amount of disparity between PG&E and ORA's forecast does not raise itself to the level of requiring balancing account treatment. Second, ORA's forecast is comparable to historical recorded spending for customer connection work. Third, ratemaking is not an exact science and this Commission, in most instances, has a track record of

[28] PG&E-2, p. 3-2.

adopting spending estimates that are based on the judgment of the parties' who present those estimates, knowing that actual spending will likely differ, to some degree, from the Commission's adopted amount . Balancing account treatment represents a move to micromanaging of PG&E's business, a move that ORA does not support.

1. Major Work Category 16

PG&E's forecast for MWC 16, in the amount of $212,625, is based on an estimate of new customer connections by customer type, multiplied by an allowance provided under Tariff Rules 15 and 16. PG&E relies on many sources to determine its estimate of customer connections, including the trend of residential housing permit activity, the amount of paid building permits, historical data and customer consultation regarding future construction plans.[29] PG&E's customer-specific forecast is presented in Exhibit PG&E-2, Table 3-8. In addition to the customer-specific data, PG&E's forecast includes amounts for non-customer connect distribution transformers, system improvements or betterment, and customer refundable allowances.

ORA reviewed PG&E's forecast data by looking at historical amounts (as available), reviewing building permit data, analyzing PG&E's customer consultation information and reviewing the process that PG&E uses to identify betterment.

Historical spending for MWC 16 is set forth below:

[29] PG&E-2, pp. 3-16 to 3-18.

Table 14-6

MWC 16 CUSTOMER CONNECTIONS
CAPITAL EXPENDITURES
(Nominal Dollars in thousands)

1996	1997	1998	1999	2000	2001	2002 adj.	7 year Avg.
160,263	208,786	210,356	226,500	223,808	194,014	194,142	202,553

PG&E's 2002 recorded capital expenditures for MWC 16 were $219 million. The 2002 expenditures included $24 million for payments to customers required by the United States Bankruptcy Court.[30] For the purpose of estimating 2003 spending, ORA adjusted 2002 recorded cost to exclude the $24 million payment because it is a one-time event. With this adjustment, the 7-year average for spending on electric customer connections is $202.5 million.

ORA recommends using this adjusted 7-year average as a basis for forecasting 2003 customer connection costs. Despite some fluctuations in spending that occurred between 1996 and 2002, the average of $202.5 million is in line with 2002 spending.

ORA assumes that 2003 spending will be similar to 2002, but slightly lower due to a continuing lagging economy. From the base of $202.5 million, ORA made an adjustment of $15 million to exclude PG&E's request for capital expenditures related to betterment, resulting in ORA's capital expenditure forecast of $188 million.

a. Forecast of Customer Connections

In addition to looking at historical spending, ORA reviewed PG&E's forecast for number of connections by customer type. PG&E relied on the May 2002 new building permit data compiled by the Construction Industry

[30] E-CIW-310

Research Board. ORA reviewed the May 2002 edition as well as the October 2002 report. Though both editions of the Construction Industry Research Board report show an increase in residential building permit data, that is not the case for non-residential permit activity. ORA compared the October data to the May data and found that the more recent non-residential permit data indicates that California building activity has decreased.

PG&E forecasted 2003 connections for Telco Customers and Server Farm/Data Center Customers. Though the number of connections are small in comparison to residential and non-residential, this type of investment is more susceptible to a sluggish economy. PG&E's 2002 experience supports a lower forecast for Server Farm/Data Center Customers.[31]

b. Betterment

MWC 16 includes costs associated with system upgrades. These upgrades or betterment work, are charged to ratepayers as a whole rather than to the connecting customer. PG&E's 2003 capital expenditure forecast for betterment work is $15 million. PG&E's estimate is based on a methodology that is inadequate to support these expenditures. ORA has performed considerable discovery in an attempt to validate PG&E's forecast by reviewing the betterment identification process. As ORA will demonstrate, the responses do not support PG&E's request.

The $15 million of betterment cost is derived by estimating the amount of betterment work that was included in projects approved during February and March 2001. During that two month period, PG&E claims that about 8 percent of the projects approved during those months had some type of betterment work included in the total cost. Based on that claim, PG&E assumes that 8 percent of all work performed under MWC 16 includes

[31] E-CIW-213, Question 8.

betterment. PG&E uses a unit cost of $5,000 for betterment work for each project.[32] The 2003 estimate assumes that 3,000 projects out of 37,500 total projects for 2003 will have betterment work totaling $5,000 per job.[33] PG&E did not provide any supporting documentation for this estimate, other than documents that generally describe the fact that PG&E is asking its engineers to identify this work. The documentation does shed light on possible incentives for PG&E engineers and managers as they make decisions regarding work associated with customer connections. For example, one memorandum suggests that "jobs are being over-designed" and that the costs associated with betterment cannot be charged to the customer, unless it meets the tariff rules. PG&E further simplifies the instructions by defining betterment as "…..the difference between what a project costs less the sum of the refundable + non refundable payment + allowances."[34] In other words, PG&E defines betterment as the cost of work performed on a connection project that you cannot charge to the connecting customer. As a result, betterment work, when identified, is charged to the ratepayers through the assignment to a MWC, such as MWC 16. [35]

PG&E's discovery responses provide no assurance that the $15 million forecast for betterment capital expenditures are reliable. Furthermore, PG&E has an incentive to over-estimate betterment costs so that they can shift these costs from the connecting customer to all ratepayers.

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[32] PG&E-2, Workpaper 3-81.

[33] This follows the logic contained in PG&E's response to E-CIW-088, Question 1.

[34] E-CIW-042, Question 19, Attachment 1.

[35] PG&E's response to E-CIW-042, Question 19, includes a list of MWCs to which betterment work can be assigned. However, PG&E claims that the review team that identified betterment work did not and could not charge to multiple MWCs for any single project. This means that all of the betterment work included in the 2003 forecast is charged to MWC 16.

This is the case because PG&E faces competition for connection work, while all ratepayers pay for work assigned to the various MWCs.

PG&E does not provide adequate support for its forecasted betterment expenditure amount and has the incentive to include more costs under the betterment definition. For these reasons, ORA remmends that the $15 million betterment charge be removed from the 2003 forecast for MWC 16 capital expenditures. ORA's 2003 capital expenditure forecast for MWC 16 is $188 million compared to PG&E's forecast of $213 million. ORA's forecast is reasonable given historical spending, current indications of connection activity, and PG&E's lack of support for identifying and charging betterment costs to ratepayers.

2. Major Work Category 30

PG&E's 2003 forecast for MWC 30 is $55 million, a 66 percent increase above the 7-year average for this category. Historical spending for MWC 30 is set forth below:

Table 14-7

MWC 30 UNDERGROUNDING EXPENDITURES
(Dollars in thousands)

1996	1997	1998	1999	2000	2001	2002	7 year Avg.
EXPENDITURES							
29,475	25,147	33,084	33,945	41,476	29,294	37,757	33,064

Tariff Rule 20A provides for a process by which PG&E can replace overhead electric distribution facilities with underground facilities. The requests for this work come from cities and counties. The tariff establishes an annual amount of money (or allocation) that is available for these projects. The total dollars are then allocated to cities and counties based on the number of meters within the city or county. The dollars, if not spent in any given year, can accumulate and be held until the city or county has sufficient funds to go forward with the project. According to PG&E, as of

2001, the fund has accumulated $296 million, and, as a result, PG&E expects to perform a large amount of undergrounding work in 2002 and 2003.[36] PG&E also claims that due to the company's financial crisis, projects were deferred , presumably as part of its cash conservation efforts. However, PG&E's predictions have not come to fruition. As Table 14-7 shows, PG&E's 2002 recorded capital expenditures for MWC 30 was $38 million, $7 million less than PG&E's 2002 forecast of $45 million.[37] In addition, the historical 7-year average capital expenditures for MWC 30 is equal to $33 million. As a result, ORA believes that PG&E has overestimated spending for this MWC. ORA recommends a 2003 capital expenditure forecast of $39 million. The $39 million forecast is reasonable because it provides additional dollars to account for PG&E's expectation for increased spending indicated by the accumulated funds for undergrounding work, is in line with historical spending and takes into account PG&E's actual 2002 expenditures.

B. <u>Pole Asset Management – MWC 07</u>

PG&E's 2003 forecast for capital spending for pole replacement work is $90.9 million, 32 percent higher than 2000 recorded cost.[38] PG&E explains that it anticipates spending more in 2003 as it makes up for the work deferred in 2000 and 2001 to conserve cash.[39]

PG&E's forecast method was to predict the number of poles it intended to replace and the associated unit cost for those poles and multiply the two to come up with forecasted capital expenditures. For the 2003 test

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[36] PG&E-2, p. 3-32.

[37] PG&E-2, Table 3-15. ORA notes that PG&E states that its 2002 forecast is $50 million on page 3-32 of Exhibit PG&E-2.

[38] PG&E-2, p.5-1.

[39] <u>Ibid</u>., pp. 5-1 to 5-2.

year forecast, PG&E assumed it would replace 15,000 poles at a cost of $6,060 per pole.[40] The per pole cost, or unit cost, is a system-wide average cost, based on the unit cost for each of PG&E's eighteen divisions. Though this methodology seems reasonable on its face, the result is a forecast that is higher than PG&E's spending over the last 6 years.

PG&E estimates its 2002 and 2003 spending by identifying the number of poles that would be replaced in each of its divisions, all with varying unit costs. This approach may not be the most appropriate way to forecast spending in this area. For example, PG&E provided ORA with documents to support the 2003 forecast, that show initial forecasts that change as the year progresses. The changes are in both the unit cost and the number of units[41]. In response to another ORA data request, PG&E reported a recorded unit cost of $5187 per pole for 2002[42], compared to a unit cost of $5813 per pole used to develop PG&E's 2002 forecast. The difference between the recorded unit cost and forecasted unit cost is significant when these unit costs are applied to 15,000 poles.[43] There is also evidence that, internally, PG&E has used a lower unit cost of $5000 per pole when preparing job estimates.[44] In addition, in the October 2002 Engineering Audit Report prepared at the Commission's request, Stone and Webster noted that the internal benchmark they use for pole replacement work in high cost areas is $5,000 per pole.[45] Finally, other internal documents used for budgeting and forecasting indicate that construction cost per pole is less than

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[40] PG&E-2, p. 5-3.

[41] E-CIW-075, Question 11.

[42] E-CIW-308, Question 2.

[43] PG&E-2 Workpaper 5-4.

[44] E-CIW-136, Question 2.

[45] Stone & Webster Exhibit, p. 5-48.

$5,000.[46] PG&E's forecast for 2002 is $87.2 million while actual 2002 spending was $78 million. This difference is likely attributable to changing priorities, and changing unit costs.

ORA expects PG&E to re-prioritize its pole replacement work over the year as the company re-assesses its pole inventory and receives new information from its pole inspection team. This means that, even though PG&E may be committed to replacing 15,000 poles per year, the actual poles replaced will likely not match the forecast. As a result, PG&E's forecast is inherently inaccurate since it is based on replacing a certain number of poles in each of its 18 divisions with 18 different associated unit costs. Once the pole mix changes, the forecast is off.

Table 14-8 shows the historical expenditures for MWC 07:

Table 14-8

MWC 07 POLE REPLACEMENT EXPENDITURES[47]

(Nominal Dollars in thousands)

1997	1998	1999	2000	2001	2002	6 year Avg.
45,955	73,167	50,919	71,567	81,241	77,836	66,781

Table 14-9 compares PG&E's and ORA's 2003 capital expenditure forecast for Pole Replacement Work:

Table 14-9

POLE REPLACEMENT CAPITAL EXPENDITURES TEST YEAR 2003

(Nominal Dollars in thousands)

	ORA	PG&E	PG&E>ORA	Percent

[46] E-CIW-075, Question 21. Actual amounts are designated proprietary by PG&E.

[47] The data in this table is from PG&E's response to E-CIW-239. In response to another data request, E-CIW-075REV, PG&E provided recorded capital expenditure amounts that, in most cases, were lower than those reflected in Table 14.8.

MWC 07	79,500	90,908	11,408	12.5%

Despite PG&E's assertion regarding deferred spending, the recorded cost data shows relatively consistent spending over the last three years. PG&E replaced over 13,000 poles in 2001[48], even with the cash crisis that PG&E was experiencing. For 2002, PG&E replaced 15,003 poles, however, the division counts changed slightly, but, more significantly, the unit costs for several of the divisions were much different, resulting in an overall decrease in unit cost and total cost. Table 14-10 compares PG&E's 2002 forecast with actual recorded data.

[48] E-CIW-075, Question 2.

Table 14-10
MWC 07
FORECAST VS. ACTUAL
UNIT COST, UNITS AND TOTAL EXPENDITURES
(Nominal Dollars)

Division	Forecast Unit Cost	Forecast Units	Forecast Total Expenditure.	2002 Unit Cost	2002 Units	2002 Expenditures [49]
Peninsula	$10,156	251	$2,549,097	$6,379	296	$1,888,000
San Francisco	$9,654	251	$2,423,095	$11,674	327	$3818,000
Diablo	$8,423	268	$2,257,301	$8,058	380	$3,062,000
East Bay	$9,567	311	$2,975,264	$10,945	278	$3,043,000
Mission	$8,296	135	$1,119,928	$9,189	158	$1,452,000
Central Coast	$7,430	1,118	$8,306,476	$5359	1,123	$6,018,000
De Anza	$8,306	301	$2,500,035	$8,968	301	$2,699,000
San Jose	$7,548	194	$1,464,363	$9,254	101	$ 935,000
Fresno	$5,048	2,226	$11,236,322	$3,641	2,570	$9,358,000
Kern	$4,743	1,063	$5,041,558	$3,283	1,104	$3,625,000
Los Padres	$4,518	781	$3,528,374	$4,080	611	$2,493,000
Stockton	$4,246	540	$2,292,712	$4,430	570	$2,525,000
Yosemite	$4,773	850	$4,056,849	$4,432	844	$3,741,000
North Valley	$4,195	1,144	$4,799,382	$3,934	1,149	$4,520,000
Sacramento	$4,228	443	$1,872,899	$4,161	443	$1,843,000
Sierra	$4,900	1,080	$5,291,745	$4,532	1,063	$4,818,000
North Bay	$7,103	1,524	$10,824,612	$6,259	1,071	$6,719,000
North Coast	$1,486	2,524	$14,678,988	$5,843	2,614	$15,257,000
System	$5,813	15,004	$87,219,000	$5,187	15,003	$77,813,000

Even if PG&E replaces 15,000 poles again in 2003, based on recent data, the average unit cost to replace those poles should be much less than

[49] E-CIW-308, Question 4, Attachment ORA_0308-04-1. The expenditures exclude reimbursable costs from telecommunication companies.

$6,061. This means that PG&E's capital expenditure forecast of $91 million is overstated.

For purposes of developing its estimate, ORA agrees to PG&E's forecast of 15,000 pole replacements in 2003 but does not agree with PG&E's unit cost. ORA derived its estimated unit cost for pole replacements by applying a 2% escalation factor to PG&E's 2002 reported unit cost of $5,187, resulting in a unit cost of $5,300. The 2% escalation factor was used by PG&E for some asset program forecasts[50] to escalate costs for the test year and provides for a modest increase in unit cost for 2003. Multiplying ORA's unit cost of $5300 by 15,000 poles results in a capital expenditure forecast for 2003 pole replacement work equal to $79.5 million.

C. <u>Underground Asset Management – MWC 56</u>

PG&E is requesting $9 million in capital expenditures for its Underground Asset Management Program for the 2003 test year. This request is over four times[51] the amount PG&E spent in 2001 for underground cable work and 34 percent more than the 2002 recorded amount.[52] PG&E's 2003 forecast relies on the assumption that 2003 spending will be equal to 2002.[53] The 2002 forecast is $9.367 million, however, PG&E's recorded 2002 spending is only $6.7 million.[54] Simply relying on PG&E's own justification for 2003 spending requires an adjustment to the 2003 forecast.

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[50] E-CIW-314, Attachment ORA_0314-01-1.

[51] PG&E-2, p. 6-1.

[52] E-CIW-0239, Question 2, revised.

[53] PG&E-2, p. 6-4.

[54] E-CIW-0239, Question 2, revised.

1. Changing MWC Definitions

ORA's review of historical spending for underground cable work was complicated because this work was previously performed under MWC 08, Mitigate Recurring Outages.[55] According to PG&E, for the years 1997 through 2003 the definition of the work performed under MWCs 08 and 56 has changed. Furthermore, for the years 1997 through 2000, PG&E claims it does not know the dollars spent on Underground Asset Management. Apparently, the changes in accounting were not tracked. PG&E did not provide, or could not provide the historical trend for budgeted and recorded capital expenditures for the Underground Asset Management Program[56]. Since it appears that MWC 56 contained most of the dollars spent on underground cable work, ORA relied on the spending trend for MWC 56 to develop an historical spending average.

2. Historical Spending

Table 14-11 shows the historical recorded cost for MWC 56:

Table 14-11

MWC 56 UNDERGROUND ASSETS EXPENDITURES

(Nominal Dollars in thousands)

1997	1998	1999	2000	2001	2002	6 year Avg.
751	2,279	4,183	3,922	2,097	6,699	3,322

The 6-year average spending is $3.3 million. It is worth noting that while 2002 spending is higher than at any time in the past 5 years, it is well below the $9.4 million that PG&E forecasted for 2002.

PG&E's historical spending record provides evidence that PG&E has a history of budgeting higher than it actually spends on cable asset

[55] E-CIW-0117, Question 1.

[56] PG&E's failure to adequately account for changes in the spending contained in its MWCs is a problem that is not peculiar to the Underground Asset Management Program.

management. Between 1997 through 2001, the average percentage difference between recorded expenditures and budgeted expenditures was 90 percent.[57] In the 1999 GRC, the Commission adopted $15 million for underground asset management work,[58] but PG&E spent only $4.2 million in 1999. Though the accounting issues make comparisons difficult, the historical data demonstrates a trend of under-spending when recorded costs are compared to both PG&E's budget and to Commission-authorized expenditures before the test year, during the test year, and after the test year.

The historical data reveals PG&E's forecasts have been as much as three times the amount of actual expenditures for underground cable replacement work. In addition, PG&E's 2002 capital expenditures of $6.7 million is 28% less than PG&E's capital expenditure forecast of $9.4 million. ORA recommends an adjustment to PG&E's 2003 forecast from $9 million to $5 million. The $5 million is reasonable in light of the average spending for this program. ORA's forecast provides PG&E with 50 percent more than the 6-year average in consideration of the increased spending in 2002. It is also 34% more than the 6-year average of $3.3 million.

V. PLANNING, BUDGETING AND FORECASTING

PG&E plans its asset program work as an input to its internal budgeting process and to develop forecasts for ratemaking purposes. ORA reviewed PG&E's methods and makes recommendations here that, if adopted, should result in improved documentation of the methods PG&E uses to plan, budget and forecast its capital spending.

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[57] E-CIW-0117, Question 1.

[58] PG&E-2, p. 6-3.

A. PLANNING AND BUDGETING

PG&E devotes a considerable portion of testimony to a discussion of the process used to prioritize asset program spending. The company divides its spending programs into three categories: (1)Safety and Compliance; (2) Customer Connection and Franchise Obligations; and (3) Maintain System Performance and Support. The first two categories represent work that PG&E must perform due to safety rules and service obligations. The last category, Maintain System Performance and Support, includes programs for which PG&E has flexibility with respect to how much work is done, and subsequently how much money is spent, as well as *which* projects are completed. Capital work in this category includes substation equipment replacement, underground cable work and dependability projects. The work performed in this category is discretionary in that PG&E can decide to defer a project without safety or compliance concerns. PG&E's methods for prioritizing this discretionary work are not adequately explained in its testimony. Though the testimony and workpapers describe how the company evaluates individual projects and chooses alternatives, there is no description of how an approved project is prioritized. In other words, out of all the projects that PG&E has approved, presumably because of a system need, there is no explanation as to how one project gets put before another. Moreover, during the course of the year the company often re-prioritizes due to changing system needs and/or funding issues. Again, it is not clear how these decisions are made.

Because PG&E does not adequately explain its prioritization process, it is difficult for ORA, other parties and the Commission to understand how discretionary projects are evaluated and re-evaluated. Just as it is important for PG&E to describe the methods used to develop its forecast, it is equally

important that PG&E document how discretionary projects are prioritized and re-prioritized.

PG&E does provide a description of the various levels of planning and review that make up its budget process. First, Program Managers develop program budgets based on the needs identified by the Directors and personnel in PG&E's eighteen divisions. The Program Manager prioritizes the work and presumably may eliminate some projects, though this is not entirely clear. From there, the budget proposal goes to the Engineering and Planning (E&P) Directors where projects are compared across asset programs and more adjustments are made. The E&P Directors then present their recommendations to the Transmission & Distribution (T&D) Finance Team and the T&D Resource Team. This level of review, which includes "…identify(ing) resource bottlenecks" and "…reprioritiz(ing) projects to fit within available resources" produces additional changes in the budget approval process.[59] Throughout the process, it is unclear how PG&E makes decisions to change an asset program budget.

Knowledge of the planning process is a prerequisite to determining the reasonableness of PG&E's requests as well as understanding how the planning process sets priorities for discretionary projects. ORA recommends that the Commission require PG&E in its next GRC to provide documentation of its planning and budgeting process that clearly describes the criteria used to evaluate and re-evaluate discretionary projects.

B. FORECASTING

PG&E's application includes discussions regarding the process PG&E uses to forecast capital additions. The basis of each forecast is the

[59] PG&E Exhibit 2, p. 1-40.

data that is used to develop the company's program asset work plans and budgets. The methods that PG&E uses to collect, utilize and track this data determines the dollar amount of capital expenditures and additions that the company is requesting for 2002 and 2003 in this GRC. Now that recorded 2002 data is available, there is evidence that PG&E over-estimated electric distribution capital additions by $119 million. It appears that the centralization of the planning and budget process has not resulted in increased forecast accuracy.

Historical data shows that PG&E has overestimated GRC capital spending both on an individual program basis and in the aggregate. Table 14-11 compares PG&E's 1999 recorded distribution capital additions compared to the Commission-authorized amounts.

Table 14-11

1999 DISTRIBUTION CAPITAL ADDITIONS[60]

(Dollars in thousands)

Plant Type	1999 Adopted	1999 Actual	Difference
Electric	$959,742	$827,857	**$131,885**
Common	$184,999	$157,092	**$27,907**
Gas	$304,119	$214,174	**$89,945**
Total	$1,448,860	$1,199,123	**$249,737**

Though PG&E was authorized $1.5 billion in capital additions in 1999, the actual recorded amount was less than $1.2 billion, a difference of close to $250 million. PG&E's internal budgeting process has resulted in over-budgeting and under spending for several of its asset programs. These

[60] C-CIW-014

differences are apparent by comparing PG&E's 2002 forecast and 2002 recorded data. As described in Section IV of this chapter, PG&E has over-budgeted its Pole Asset Management Program, Underground Asset Management Program and Undergrounding Programs. Spending in the Electric Distribution Capacity Program was under budget in 2002, and significantly under budget in 2001.[61]

ORA's observation regarding PG&E's forecasting experience is validated by the consultants Stone & Webster in their 1999 Capital Expenditure Audit Report. That report included a finding that "….PG&E routinely under-ran its project budgets".[62] As a result, ORA did not rely on PG&E's forecasting approach alone, and instead attempted to validate the forecast amounts by reviewing historical data. Actual recorded costs are useful as a comparison tool with which to assess PG&E's forecasting approach.

C. TRACKING AND RECORD-KEEPING

One of the shortcomings of PG&E's forecasting methodology is that there is no system in place to track actual project expenditures and compare those to the original budget and original job estimates for those projects. An example is PG&E's Pole Asset Management Program. PG&E does not track actual dollars spent on pole replacement projects against the estimates made in the field, despite the fact that they track both by order number.[63] As a result, PG&E's budget/forecast process is not checked or evaluated against actual experience. For pole projects, the difference between actual expenditures and budget projections were significant. ORA compared these

[61] E-CIW-0084, Questions 5 and 6.

[62] Stone & Webster, p. 7-3.

[63] E-CIW-075, Question 22.

amounts and found them to vary widely. The process, though tedious to do manually, could either be incorporated into PG&E's SAP accounting system, or tracked separately by the Pole Asset Management group. This information would allow PG&E to identify the projects with large variances and engage in further analysis to determine the reasons for the variance.

PG&E could also improve its record-keeping system for pole replacement work by establishing a link between the test and treat program and the pole inspection activities. The test and treat process sometimes results in a pole being identified as needing replacing or reinforcement. However, this information, though recorded, is not tracked in any systematic way and is not reviewed until a pole inspection is done. For example, ORA visited two of PG&E's pole replacement projects and also followed up with discovery requesting records and reports for test and treat, inspections and patrols. For one of the poles in question, the pole was identified as needing replacement when it was surveyed by the test and treat crew. However, it wasn't until a pole inspection occurred, 5 years later, that the pole was officially identified as needing replacement.[64]

For poles identified for replacement or reinforcement by either the test and treat program or by a scheduled pole inspection, ORA recommends that PG&E record the assessment dates, the date when the replacement or reinforcement need is confirmed, and the date that the pole is actually replaced or reinforced. The benefits from these changes will be increased efficiency, better forecasting, and better data for setting priorities for pole replacement and reinforcement work. These same benefits could be realized for all of PG&E's asset programs. ORA recommends that PG&E establish a

[64] E-CIW-075, Question 18 attachments.

process for comparing recorded expenditures to the original budgets and job estimates for all of its asset programs.

D. CHANGES IN MWC DEFINITIONS

As discussed in Chapter 6 of ORA's Report, PG&E's reliance on functional accounting complicated ORA's review of PG&E's expenses. There were also impacts on ORA's review of capital spending. PG&E began using the SAP accounting system in 1996. In general, PG&E has been able to provide MWC historical data as far back as 1997. However, there were several instances where PG&E changed the definition of the MWC. For example, PG&E made considerable changes to the definition of several major work categories between the adoption of the 1999 GRC decision and the recording of 1999 capital expenditures.[65] The previous discussion regarding the Underground Asset Program illustrates the difficulties presented by PG&E's decision to change a definition without any accommodation to track how that change impacts the accounts. For PG&E's capital MWC accounts, almost all have experienced a change in definition, some more than once. According to PG&E, however, there is no way to track the changes to allow for accurate comparisons of spending.[66]

PG&E has an obligation under the Rate Case Plan to track at least five years of historical spending and financial information to accommodate the regulatory process[67]. ORA recommends that the Commission require PG&E to identify all changes to its accounting system and account definitions and adjust MWCs on a historical basis so that recorded information is provided on a consistent basis with any revisions. This will

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[65] E-CIW-111.

[66] G-DAO-214.

[67] D.89-01-040, App. B, p. 22.

allow the Commission and the parties to the proceeding to make meaningful comparisons of historical spending.

VI. CONCLUSIONS

PG&E's 2002 and 2003 forecast of capital expenditures should be adjusted consistent with ORA's recommendations set forth above. For 2002, ORA recommends using actual recorded data. For 2003, ORA recommends adjusting PG&E's forecast by $56.4 million, resulting in capital expenditures of $596 million.

ORA recommends that the Commission require PG&E to institute changes to its planning, budgeting and forecasting methodology to address inadequacies in PG&E's forecasting approach and to facilitate review of PG&E's forecast in the next rate case. ORA recommends the Commission require PG&E to make some accommodation for changes in the functional accounting system that will allow the Commission, parties, and PG&E to review consistent historical data. Finally, ORA requests that the Commission order PG&E to adjust its budgeting process to allow for comparisons of forecasts, job estimates and actual dollars spent. These changes will improve the GRC review process as well as PG&E's forecast and budgeting methodology.

CHAPTER 15

PLANT: COMMON, GENERAL AND INTANGIBLE[1]

I. INTRODUCTION

This chapter addresses the forecast of common plant expenditures and additions for the 2003 test year. PG&E sets forth its request for common plant capital expenditures in Exhibits PG&E-2, PG&E-3 and PG&E-4. PG&E's request for common plant capital additions are shown in Exhibit PG&E-6. This chapter presents ORA's analysis of the company's proposal and presents recommendations for adjustments to PG&E's request for common plant expenditures and additions.[2]

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations. Section III presents ORA's analysis of PG&E's request and support for ORA's forecasts and adjustments to MWCs 04 and 78. Section IV describes the conversion of ORA's adjustments to capital additions. Section V provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

PG&E asks the Commission to adopt its forecast for common plant additions[3] of $315.6 million for 2002 and $208.5 million for 2003.[4] PG&E's common plant additions are based on forecasted capital expenditures of $247 million for 2002 and $210 million for 2003.[5] ORA recommends that the

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[1] ORA did not review or change PG&E's General Plant and Intangible Plant Additions.

[2] ORA's Information Technology testimony is presented in Chapter 12 of this report. The plant accounts associated with IT are not reviewed in this chapter. Common plant allocations are covered in Chapter 11 of this report.

[3] As described in Chapter 14 of ORA's report, PG&E presents its capital forecast as expenditures which are then converted to capital additions by PG&E's RO model.

[4] PG&E-6, p. 8-22.

[5] PG&E-6, p.8-22.

Commission adopt common plant expenditures of $214.4 million[6] and common plant additions of $274 million[7] for 2002 which equal PG&E's 2002 recorded capital expenditures and additions. For 2003, ORA forecasts $161 million in capital expenditures and $153 million in capital additions[8]. ORA's adjustments are based on a review and analysis of specific common plant MWCs. ORA reviewed historical spending and evaluated PG&E's forecasting and budgeting process that led to PG&E's estimates for 2002 and 2003.

As stated in Chapter 14 of ORA's Report, PG&E's forecast is developed by estimating expenditures, not capital additions. ORA analyzed PG&E's expenditure forecasts as well as the resulting capital additions calculated by PG&E's RO model. The RO Model allocates the 2003 Weighted Average (WAVG) common plant to electric distribution, gas distribution and retained generation. ORA's witness Harpster addresses the allocation of common plant to the various plant functions. The allocation of common plant to these functions will be incorporated into the total WAVG plant for each of these plant types and will be included in rate base.

Table 15-1 presents the differences between ORA's and PG&E's capital additions, retirements, end-of-year common plant balances and WAVG additions for the 2002 and 2003 test year.

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[6] E-CIW-239, Attachment ORA_0239-04-1REV.

[7] E-CIW-265, question 1, Attachment ORA_0265-01-1.

[8] ORA's recommendation includes the IT common plant MWCs. PG&E's IT forecasts are reviewed in Chapter 12 of ORA's report.

Table 15-1

COMMON PLANT
FUNCTIONAL PLANT SUMMARY
(In Thousands of Nominal Dollars)

PG&E's Forecast						
2001 EOY Balance	2002 Forecast Additions	2002 Forecast Retmnts.	2002 EOY Balance	2003 Forecast Additions	2003 Forecast Retmnts.	2003 WAVG Additions
3,015,444[9]	315,632[10]	172,856[11]	3,158,220	208,556[12]	149,670[13]	83,620[14]
ORA's Recommendation						
2001 EOY Balance	2002 Recorded Adds.	2002 Recorded Retmnts.	2002 EOY Balance	2003 Forecast Additions	2003 Forecast Retmnts	2003 WAVG Additions
3,015,444	274,302[15]	167,073[16]	2,816,810	153,062	136,917	53,830

Table 15-2 compares PG&E's and ORA's common plant expenditures

[9] PG&E-8, Workpaper 8-22

[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] PG&E-8, Workpaper 8-22.

[14] Ibid.

[15] E-CIW-265, Attachment ORA_0265-01-1

[16] C-CIW-143, Attachment ORA_0143-01-1RevSupp, p. 10.

Table 15-2

COMPARISON OF COMMON PLANT EXPENDITURES
TEST YEAR 2003
(Nominal Dollars in Thousands)

MWC	Description	ORA	PG&E	PG&E>ORA	Percent
MWC 01	IT-Desktop Comp.	11,500	11,500	0	0%
MWC 02	IT-Voice Comm.	5,000	5,000	0	0%
MWC 03	Office Furn.& Equip.	0	0	0	0%
MWC 04	Fleet Services	60,000	72,900	12,900	17.7%
MWC 05	Tools & Equipment	2,454	2,454	0	0%
MWC 12	Environmental	1,631	1,631	0	0%
MWC 28	Electric Vehicle	463	463	0	0%
MWC 31	Natural Gas Vehicle	3,993	3,993	0	0%
MWC 53	IT-Applications	5,819	5,819	0	0%
MWC 77	IT-CIS	8,400	8,400	0	0%
MWC 78	Building & Land	22,893	59,023	36,130	61.2%
MWC 79	Land Management	30	30	0	0%
MWC 80	Comp.Network F&E	5,271	5,271	0	0%
MWC 85	IT-Infrastructure	30,000	30,000	0	0%
MWC 87	Office Equipment	1,500	1,500	0	0%
MWC 88	Office Furniture	2,142	2,142	0	0%
TOTAL		161,096	210,126	49,030	23.3%

Table 15-3 presents the differences between ORA's and PG&E's Weighted Average Plant-In-Service balances for the 2003 test year.

Table 15-3

WEIGHTED AVERAGE PLANT-IN-SERVICE BALANCES
TEST YEAR 2003
(Nominal Dollars in Thousands)

	ORA	PG&E	Difference
	Recommended	Proposed[17]	PG&E - ORA
Common Plant	2,819,132	2,875,924	56,792
General Plant	215,928	210,485	-5,443
Intangible Plant	94,036	97,436	3,400
TOTAL	3,129,096	3,183,845	54,749

Table 15-4 presents the differences between ORA's and PG&E's common plant expenditures for the 2003 test year.

Table 15-4

COMMON PLANT CAPITAL EXPENDITURES AND ADDITIONS
TEST YEAR 2003
(Nominal Dollars in Thousands)

	ORA	PG&E	PG&E>ORA	Percent
Expenditures	160,764	210,126	49,362	23.5%
Additions	153,062	208,556	55,494	26.6%

III. ADJUSTMENTS

PG&E's common plant expenditures forecast for 2003 is $210 million and includes desktop computers, communications equipment, office furniture, fleet services, tools, environmental, electric and natural gas vehicles, building services and land management. As stated in the introduction to this chapter, PG&E's presentation of these costs is contained in several exhibits, and some MWCs are presented in multiple chapters.

ORA's common plant expenditure forecast for 2003 is $161 million. ORA's forecast is $49 million less than PG&E's forecast. Consistent with the approach

[17] PG&E-6, Workpaper 8-451.

discussed in Chapter 14, ORA proposes specific adjustments to some, but not all of the common plant MWCs. ORA prioritized its review of these plant categories by focusing on the programs with the largest dollar forecast expenditures for the test year. Addressed below are the programs and MWCs for which ORA is proposing an adjustment for the 2003 test year.

The capital portion of these programs apply to the entire utility, not just electric and gas distribution. The dollars presented and discussed below represent the costs for the entire company. Once monthly capital expenditures are determined, the costs are re-stated as capital additions by the RO model and then allocated to the 29 unbundled cost categories. This testimony addresses total common plant expenditures and additions, not the assignment of these costs to each type of plant.[18]

A. Fleet Services – MWC 04[19]

PG&E's forecast for fleet services is presented in Exhibit PG&E-4, Chapter 9. MWC 04 includes all costs of purchasing and replacing vehicles. This includes automobiles, trucks, trailers and power-operated equipment. PG&E's 2003 forecast is $72.9 million. The 2003 forecast is high compared to previous years' spending, as illustrated in Table 15-5.

Table 15-5

MWC 04 HISTORICAL AND AVERAGE SPENDING
1997-2002
(Nominal Dollars in Thousands)

1997	1998	1999	2000	2001	2002	6 year Avg.
84,995	29,806	32,705	56,475	48,597	50,833	50,569

[18] The allocation of common plant additions to specific plant types is addressed in Chapter 11.

[19] A portion of MWC 05, Tools and Equipment, is captured by this program. ORA did not make any adjustments to MWC 05.

PG&E's 2002 capital expenditure forecast for Fleet Services is $42 million. As can be discerned from Table 15-5, PG&E actually spent $51 million. PG&E's recorded 2002 spending supports PG&E's argument of increased spending on fleet, but the additional $7.6 million spent in 2002 could also serve to offset 2003 spending. As illustrated in Table 15-6, despite the 2002 experience, PG&E has, with the exception of the year 2000, underspent its fleet budget.

Table 15-6
HISTORICAL FLEET EXPENDITURES
BUDGETED VS. RECORDED[20]
(Nominal Dollars in Thousands)

Year	Budgeted	Recorded	Diff.(Bud.-Rec.)	Percent Difference
1997	108,926	84,995	23,931	22%
1998	66,168	29,806	36,362	55%
1999	37,751	32,705	5,046	13.4%
2000	43,000	56,475	-13,475	-31.3%
2001	50,448	48,597	1,851	3.6%
2002	43,156	50,833[21]	-7,677	-17%

PG&E supports its increase request for fleet services as due to the need to replace aging fleet, setting forth standardized specifications which should reduce future fleet costs, and reconfiguring its fleet by reducing the number of automobiles and increasing the number of "trouble truck" units, and early replacement of vehicles with alternative fueled vehicles.[22] For the most part, ORA does not disagree with PG&E's goals for its fleet services program. However, PG&E has not provided adequate explanation to support

[20] C-CIW-124, Question 2. Budgeted amount represents PG&E's internal budget/forecast, not CPUC authorized.

[21] E-CIW-239, Attachment ORA_0239-04-1REV.

[22] PG&E-4, p. 9-9 to9-10.

its intention to spend additional dollars to replace vehicles before they have exceeded their economic life.

ORA proposes a $13 million adjustment to PG&E's 2003 forecast of $73 million resulting in $60 million for MWC 04. Sixty million dollars is reasonable because it allows for a 20% increase over 2002 spending levels for the 2003 test year and is more in line with the historical capital expenditures. The estimate also exceeds PG&E's capital expenditures in each of the proceeding 5 years.

B. <u>Building and Land Services</u>

PG&E's forecast for Building and Land Services is set forth in Chapter 12 of Exhibit PG&E-4. There are 4 capital MWCs for Building and Land Services, MWC 05, Tools and Equipment, MWC 78, Manage Buildings, MWC 79, Land Management and MWC 88, Office Furniture. ORA made no adjustments to MWCs 5, 79 and 88. ORA 's adjustments to MWC 78 are explained below.

PG&E's 2003 capital expenditure forecast of $59 million is 65 percent more than 2001 recorded. PG&E cites its 2001 cash conservation efforts as the reason for lower spending in 2001. The company also cites seismic upgrade projects and other facility improvements as a justification for the increase.[23]

Table 15-7 contains historical spending data for MWC 78.

[23] PG&E-4, p. 12-2.

Table 15-7

MWC 78 HISTORICAL AND AVERAGE SPENDING
1997-2002
(Dollars in thousands)

1997	1998	1999	2000	2001	2002	6 year Avg.
12,319	18,163	29,081	38,382	18,436	20,878	22,893

ORA reviewed historical spending, including spending in 2002, the company's support for the higher forecast amounts, and the status of several seismic upgrade projects. As shown in Table 15-7, the 6-year average spending for MWC 78 is $23 million. Spending in 1999 and 2000 was higher than previous years. ORA notes that PG&E's 2001 expenditures of $18 million does not vary much from the historical average spending for MWC 78. PG&E's assumption that its cash conservation efforts in 2001 would result in increased spending in 2002 and 2003 is not supported by recorded data. PG&E's 2001 expenditures are consistent with the 6-year historical average spending and PG&E's 2002 expenditures were only $2 million more than 2001. PG&E spent $21 million in 2002 or $20 million less than its forecast.[24]

PG&E explains that the 2002 and 2003 forecasts are based on 2001 recorded expenses that are then verified through competitive bidding and by published industry market data. The company cites necessary expenditures for seismic work, building projects and site redevelopment projects and user-requested projects as justification for the forecasts.[25] ORA reviewed PG&E's estimates for the 2002 and 2003 forecast year compared with 2001. There are large increases associated with Building Systems Projects, Redevelopment Projects, Yard Projects and Seismic Projects that are not

[24] PG&E-4, p. 12-16.

[25] PG&E-4, 12-11 to 12-13.

adequately explained or supported in PG&E's application or by the 2002 spending experience.[26] PG&E has not justified the increase in spending in either its testimony or workpapers.

PG&E's forecasts for seismic work illustrate how the company over-budgets its building and land services program. PG&E estimates that it will spend $8.4 million on seismic projects in 2003, which is close to $3 million more than PG&E planned to spend in 2002. Current and historical spending patterns indicate that PG&E will not spend $8.4 million on seismic upgrades in 2003.

For example, PG&E forecasted $3.423 million for a series of seismic upgrade projects that were scheduled for completion at the end of 2002.[27] PG&E's 2002 recorded capital expenditures for these seismic upgrade projects was only $129,041.[28] However, PG&E's RO model adds $3.423 million to plant by the end of 2002[29]. This example demonstrates the magnitude of difference between PG&E's forecast and recorded data. It also suggests that PG&E has not used actual experience concerning project status and spending to develop and support its forecasts.

As indicated in Table 15-8, historical comparisons of budgeted to actual dollars spent shows a continual pattern of over-budgeting for MWC 78.

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[26] PG&E-4, Workpaper p. 12-8.

[27] PG&E-4, Workpaper 12-24.

[28] C-CIW-340, Question 1, Attachment ORA_0340-01-2.

[29] PG&E's RO Model has this amount going into plant in 2002. The updated model that ORA is using starts at EOY 2002 and should reflect only actual recorded plant, and should exclude the $3.423 million. However, ORA did not have the time to review and verify the updated RO Model.

Table 15-8
HISTORICAL BUILDING AND LAND EXPENDITURES
BUDGETED VS. RECORDED[30]
(Nominal Dollars in Thousands)

Year	Budgeted	Recorded	Diff.(Bud.-Rec.)	Percent Difference
1997	42,183	12,419	29,764	70.5%
1998	53,294	18,163	36,362	68%
1999	43,600	29,081	35,131	80.6%
2000	41,228	38,382	2,846	6.9%
2001	36,068	18,436	17,632	49%
2002	41,737	20,878[31]	20,859	50%

PG&E's forecasts have not been a good indicator of actual spending on the Building and Land Services Program. Based on the above, ORA recommends that PG&E's 2003 capital expenditure forecast of $59 million for MWC 78 be adjusted by $36 million to reflect expenditures of $23 million, which is consistent with historical expenditures for Building and Land Services.

IV. CAPITAL ADDITIONS[32]

ORA made adjustments to the capital expenditures portion of the RO model to incorporate the changes recommended in this chapter for the 2003 test year. PG&E's model included $21.5 million in 2002 CWIP for common plant. The $21.5 million is added to 2003 plant along with the 2003 capital expenditures. This amount is excessive given the fact that PG&E booked $274 million to plant in

[30] ECIW-120, Question 1. Budgeted amount represents PG&E's internal budget/forecast, not CPUC authorized.

[31] E-CIW-239, Attachment ORA_0239-04-1REV.

[32] ORA provides a general discussion of the conversion of expenditures to additions in Chapter 14,Section IV. That general discussion applies to common plant as well as gas distribution plant which is discussed in Chapter 16 of this report.

2002[33]. PG&E's December 2002 CWIP balance was $18.8 million down from $73 million in January 2002, again showing that a significant amount of plant was booked in 2002. As a result, ORA removed the 2002 CWIP amount for common plant. ORA's adjustment is reasonable given the 2002 experience as well as PG&E's historical CWIP balances.

The updated RO model includes an adjustment for 2003 COR to address the double-counting of these costs in the original RO Model. The impact on capital additions from this adjustment is a reduction of $332,000 for the 2003 test year.

V. CONCLUSIONS

PG&E's 2002 and 2003 forecast of common plant capital expenditures and capital additions should be adjusted consistent with ORA's recommendations set forth above. For 2002, ORA recommends adjusting PG&E's capital expenditure forecast of $247 million by replacing it with 2002 recorded expenditures equal to $214 million. PG&E's 2002 capital additions of $315.6 million should be adjusted to $274 million to reflect actual recorded capital additions. For 2003 ORA recommends adjusting PG&E's forecast of $210 million by $49.3 million, resulting in capital expenditures of $161 million. PG&E's 2003 capital additions of $208.5 million should be adjusted to $153 million, a reduction of $55.5 million for the 2003 test year.

[33] E-CIW-265, Attachment ORA_0265-01-1. PG&E's 2002 monthly CWIP balances are consistent with the fact that a large amount of plant was booked in 2002. See E-CIW-143, Attachment ORA_0143-01-1RevSupp.

CHAPTER 16

GAS DISTRIBUTION PLANT

I. INTRODUCTION

Pacific Gas & Electric's (PG&E) plant is made up of functional plant and common, general and intangible plant. PG&E further separates its plant into unbundled cost categories (UCC) and by functional group. For gas distribution plant, the functional plant is allocated under UCC "GD-Gas Distribution Pipes and Services, 23" and under functional groups "GDP," "GDPL," "GLS," and "GLSL." The common, general and intangible plant is allocated under UCC "GD-Gas Procurement Administration, 24," and under UCC "GD-Gas Distribution Pipes and Services, 23, " with the following functional groups: CAU, CCE, CDH, CIS, CNP, COE, COT, CST, CSTL, CSW, GGP, and GGPL. In this GRC, while PG&E is requesting capital expenditures and additions allocated to common plant, this chapter will only address the expenditures and additions as they relate to gas distribution functional plant. See Chapters 10 and 15 for ORA's discussion and allocation of common plant. This chapter also does not address assets allocated to functional groups GDPL, GLS and GLSL. Although these functional groups are part of gas distribution functional plant, they represent plant assets associated with land, land rights, and gas local storage facilities with amounts that carryover from year to year. In this Application, PG&E is not requesting any changes in the amounts of these assets for 2002 or 2003 from 2000 and 2001 recorded end-of-year (EOY) plant.[1] PG&E's gas distribution functional plant request for 2002 and 2003

[1] In 2000, the amount of plant allocated to GDPL was $23.151million, $9.848 million to GLS, and $1.360 million to GLSL. In 2001, there were only minimal changes in these balances with $23.269 million for GDPL, $9.848 million for GLS, and $1.361 million for GLSL. (PG&E-2,

only directly impacts the functional group GDP of UCC GD-Gas Distribution Pipes and Services, 23. This chapter presents ORA's analysis and recommendation regarding PG&E's request for gas distribution functional plant, which will be referred to simply as "gas functional plant" from this point forward.

PG&E requests the adoption of its 2000 and 2001 recorded and 2002 and 2003 forecast for gas distribution plant expenditures with its 2003 General Rate Case (GRC) filing. The company sets forth its request in Exhibit PG&E-2, Chapter 3, "Customer Requested Construction," Chapter 10 "Meter Purchases and Maintenance," and Chapter 13 " Gas Distribution Operations." This chapter presents ORA's analysis of the company's proposal and present recommendations in response to PG&E's requests.

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, and Section III presents ORA's analysis of PG&E's 2002 forecast and actual recorded plant. Section IV presents ORA's analysis of PG&E's 2003 request and support for ORA's forecasts and adjustments by Major Work Category (MWC). Specifically, ORA will address the following MWCs in this chapter: MWC 14, "Gas Pipeline Replacement Program," MWC 27, "Gas Meter Protection-Capital," MWC 29, "Gas Distribution Customer Connects," MWC 47, "Gas Distribution New Capacity," MWC 50, "Gas Distribution Reliability," MWC 51, "Gas Distribution Work Requested by Other," MWC 52, "Gas Distribution Emergency Response," and MWC 74, "Gas Meters." Finally, Section V provides ORA's conclusions.

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p. 8-135 and 8-187 for recorded 2000 and 2001 plant and p. 8-293 and p. 8-399 for 2002 and 2003 forecast plant.

II. SUMMARY AND RECOMMENDATIONS

In its Application, PG&E is requesting that the Commission adopt $5.414 billion as the weighted average (WAVG) gas distribution plant for 2003.[2] This is comprised of $4,430 million in gas functional plant-in-service and $984 million in allocated common plant. ORA recommends a total WAVG gas distribution plant-in-service of $ 5.349 billion, which is comprised of $4,403 million in Gas functional plant and $946 million in allocated common plant. ORA recommends using 2002 recorded data, and the 2003 forecast additions to estimate the EOY plant balance. ORA's gas distribution plant recommendation includes $170.4 million in additions to functional plant for 2003 and $74.3 million in WAVG net additions to functional plant. PG&E has forecasted $190.7 million in gross additions to functional plant[3] and $86.1 million in WAVG net additions to functional plant in 2003. The difference of $ 20.3 million in gross additions and $11.8 million in WAVG net additions to functional plant is due to differences in ORA's and PG&E's estimating methodology. Table 16-1 below presents a summary of PG&E's and ORA's forecast for functional gas distribution plant. Table 16-2 presents a summary of PG&E's and ORA's forecast for total gas distribution plant, which includes expenditures for functional and common plant.

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[2] The amount of WAVG plant balance for 2003 is based on PG&E's forecast of 2002 EOY plant.

[3] This total is $3.900 million less, due to the removal of MWC 91 expenditures and additions from PG&E's 2003 forecast in Table 8-3, PG&E-2, p. 8-6.

Table 16-1

SUMMARY OF PG&E'S AND ORA'S 2003 FORECAST
GAS DISTRIBUTION FUNCTIONAL PLANT SUMMARY
(In Thousands of Nominal Dollars)

PG&E'S 2003 FUNCTIONAL PLANT FORECAST						
	2002 EOY Balance	2003 Forecast Additions	2003 Forecast Retirements	2003 Net Plant Additions	2003 WAVG Net Plant Additions	2003 WAVG Plant
Functional	*4,343,646*	*190,726*[4]	*20,918*[5]	*169,808*	*86,068*	*4,429,714*
ORA's 2003 FUNCTIONAL PLANT FORECAST						
Functional	*4,328,600*[6]	*170,383*[7]	*17,447*	*152,936*	*74,281*	*4,402,881*
PG&E>ORA						
Functional	***15,046***	***20,343***	***3,471***	***16,872***	***11,787***	***26,833***

[4] PG&E did not allocate any amount to UCC 23, Gas Procurement Administration, functional plant.

[5] This amount represents the total functional plant retirement PG&E forecasted for 2003. This amount is allocated under Normal Retirements. PG&E did not forecast any Major or Vintage retirements for Functional plant in 2003.

[6] PG&E informed ORA that its 2002 recorded plant is net of $7.9 million in cost of removal that PG&E provided to ORA in response to ORA DR 328, Q. 1.

[7] This amount represents $170,298,000 of UCC 23, functional plant and $85,000 of UCC 24, functional plant net cost of removal.

Table 16-2

SUMMARY OF PG&E'S AND ORA'S 2003 FORECAST GAS DISTRIBUTION PLANT—PIPES AND SERVICES (UCC 23) AND GAS PROCUREMENT ADMINISTRATION (UCC 24) (FUNCTIONAL, COMMON, GENERAL & INTANGIBLE PLANT)

(In Thousands of Nominal Dollars)

PG&E'S 2003 GAS DISTRIBUTION PLANT FORECAST						
	2002 EOY Balance	**2003 Forecast Additions**	**2003 Forecast Retirements**	**2003 Net Plant Additions**	**2003 WAVG Net Plant Additions**	**2003 WAVG Plant**
Functional	*4,343,646*	*190,726*	*20,918*[8]	*169,808*	*86,068*	*4,429,714*
Common & General	974,493	63,297	41,611[9]	21,687	9,935	984,428
TOTAL	5,318,139	254,023	62,529	191,494	96,003	5,414,142
ORA'S 2003 GAS DISTRIBUTION PLANT FORECAST						
	2002 EOY Balance	**2003 Forecast Additions**	**2003 Forecast Retirements**	**2003 Net Additions**	**2003 WAVG Net Plant Additions**	**2003 WAVG Plant**
Functional	*4,328,600*[10]	*170,383*[11]	*17,447*	*152,936*	*74,281*	*4,402,881*
Common & General	954,819	----------	----------	----------	----------	946,051
TOTAL	**5,283,419**	----------	----------	----------	----------	5,348,932
PG&E>ORA						
Functional	*15,046*	*20,343*	*3,471*	*16,872*	*11,787*	*26,833*
Common & General	19,674	----------	----------	----------	----------	38,377
TOTAL	**34,720**	----------	----------	----------	----------	**65,210**

[8] This amount represents the total functional plant retirement PG&E forecasted for 2003. This amount is allocated under Normal Retirements. PG&E did not forecast any Major or Vintage retirements for functional plant in 2003.

[9] This amount represents the total common and general plant retirement PG&E forecasted for 2003. This amount is allocated under Normal and Vintage retirements. PG&E did not forecast any Major retirement for common and general plant in 2003

[10] PG&E informed ORA that its 2002 recorded plant is net of $7.9 million in cost of removal that PG&E provided to ORA in response to ORA DR 328, Q. 1.

[11] This amount represents $170,298,000 of UCC 23, functional plant and $85,000 of UCC 24, functional plant net cost of removal.

ORA's adjustments represent a decrease of $20.4 million in capital additions to functional plant. Included in ORA's adjustments is the removal of $6.7 million in cost of removal for 2003 that PG&E inappropriately included in its 2003 plant forecast.[12] ORA's analysis and recommendations, which totaled $13.7 million in adjustments to individual MWCs, is discussed below. ORA's adjustments also include a retirement forecast that is $2.7 million less than PG&E's forecast because ORA used a 6-year average, which included 2002 recorded data, in its 2003 estimate. ORA's retirement forecast is 10.24% of gross additions in contrast to PG&E's forecast of 10.97% of gross additions. Additionally, ORA's adjustments resulted in a decrease of $12.2 million in WAVG net additions to functional plant due to ORA's use of an average weighting percentage of 48.57% based on the last 6 years, 1997-2002, of recorded WAVG plant additions in contrast to PG&E's weighting percentage of 50.68%.

ORA's 2003 forecast of capital expenditures is equivalent to capital additions for gas distribution (adjusted for cost of removal). ORA has made allowance for Construction Work In Progress (CWIP) in its adjustments and its 2003 forecast is reflective of this account. ORA acknowledges that there is always an amount of money in the CWIP account, for projects that are not yet completed and not yet booked to plant in service, that carry over from month to month and year to year. ORA's adjustments in capital expenditures and additions to individual MWCs are summarized in Table 16-3 below.

[12] PG&E data response to ORA DR 328, Q. 1 and Q. 4.

Table 16-3

ORA vs. PG&E 2003 CAPITAL EXPENDITURES AND ADDITIONS
SUMMARY OF ADJUSTMENTS BY MWC
(In Thousand of Nominal Dollars)

MWC	PGE	ORA	PGE>ORA	% OF DIFF.
14	67,900	67,900	0	0%
27	700	700	0	0%
29	61,301	52,700	8,601	14.0%
47	4,240	3,540	700	16.5%
50	16,000	14,800	1,200	7.5%
51	18,000	17,000	1,000	5.6%
52	200	200	0	0%
74	22,385	20,200	2,185	9.8%
TOTAL	**190,726**	**177,040**	**13,686**	**7.2%**

III. DISCUSSION/ANALYSIS—2002 EXPENDITURES AND PLANT ADDITIONS

Gas distribution plant includes the cost of assets such as distribution gas mains, gas meters, valves, regulator stations etc. and capitalized labor. These distribution assets represent about 88 % of plant costs assigned to distribution rate base while the other 12 % of distribution plant costs represent common plant costs, such as distribution service centers, call centers, vehicles and a portion of PG&E's utility headquarters.[13]

In its Application, PG&E forecasts $182.1 million in capital expenditures and $204.6 million in capital additions for gas distribution plant in 2002. The difference of $22.1 million between expenditures and additions represents the total amount of CWIP as of December 2001. For 2003, PG&E forecasts $190.7 million in capital expenditures and additions for gas distribution plant.

PG&E was able to provide ORA with recorded 2002 capital expenditures and additions for gas distribution plant. PG&E's 2002 actual expenditures and

[13] PG&E-6, p. 8-1.

additions are $2.4 million and $26.2 million less than what PG&E had originally forecasted for 2002. See Table 16-4 below for a summary of PG&E's 2002 forecast and recorded capital expenditures and additions for gas distribution plant by MWC.[14]

Table 16-4
SUMMARY OF PG&E's 2002 GAS DISTRIBUTION PLANT
(In Thousands of Nominal Dollars)

PG&E's 2002 FORECAST AND ACTUAL							
		Forecast	Recorded		Forecast	Recorded	
MWC	Description	Expenditures	Expenditures	DIFF.	Plant Additions	Plant Additions	DIFF.
14	GPRP	66,349	63,222	(3,127)	78,054	67,705	(10,349)
27	Meter Protection	1,222	420	(802)	1,406	576	(830)
29	Customer Connections	58,600	59,668	1,068	62,518	55,520	(6,998)
47	New Capacity	4,000	3,260	(740)	4,813	3,977	(836)
50	Dist. Reliability	14,599	14,375	(224)	16,900	13,945	(2,955)
51	WRO	18,000	18,382	382	21,131	16,970	(4,161)
52	Emergency Res.	200	132	(68)	230	154	(76)
74	Meters	19,535	20,619	1,084	19,582	19,619	(37)
Total		182,504[15]	180,078	(2,426)	204,635[16]	178,467	(26,168)

As Table 16-3 above shows, in 2002 PG&E spent $180.1 million and added 178.5 million to gas distribution plant in gross additions. PG&E had forecasted $182.5 million in expenditures and $204.6 million in gross additions for 2002. PG&E's 2002 data shows that PG&E spent $2.4 million less in expenditures and

[14] PG&E data response to ORA DR 251, Q. 1

[15] This total is $3.864 million less, due to the removal of MWC 91 expenditures from PG&E's 2003 forecast in Table 8-3, PG&E-2, p. 8-6.

added $26.2 million less to plant in gross additions than originally projected in its Application. PG&E's 2002 actual expenditures and additions are almost the same in amounts with only approximately $1.6 million in variance. The capital expenditures would have been noticeably less than the additions but due to a one-time accrual of $9.1 million in expenditures in September 2002 to MWC 29, (an amount two and three times higher than all other months[17]) as part of the March 25, 2002 Bankruptcy Court order, the difference between capital expenditures and additions is minimal. According to PG&E, the Bankruptcy Court order requires the company to (1) assume executory main line extension contracts and (2) pay outstanding amounts due under non-executory main line extension contracts. PG&E further states that this contract requires the company to reimburse the customer for performing work that is the responsibility of PG&E.

PG&E provided ORA with the 2002 retirements for gas distribution plant, UCC 23, functional group GDP. The total amount of 2002 plant retirements is $11.6 million. This represents 6.5% of total plant additions for 2002. In 2001, PG&E's gas plant retirements were $19.2 million, which represented 10.97% of total plant additions.

ORA finds PG&E's 2002 recorded plant expenditures and additions to be reasonable and accepts the company's overall total of $178.5 million in 2002 capital additions. ORA notes that there is a discrepancy of $3.9 million in capital expenditures and additions for MWC 91 in PG&E's 2003 forecast as presented in Exhibit PG&E-6, Table 8-3, of its Application. The expenditures and additions for this MWC are only summarized in Table 8-3 and do not appear elsewhere in PG&E's Application or workpapers pertaining to gas distribution plant. PG&E's 2003 forecast for gas distribution plant should be corrected. ORA has adjusted its

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[16] This total is $3.607 million less, due to the removal of MWC 91 additions from PG&E's 2003 forecast in Table 8-3, PG&E-2, p. 8-6.

[17] PG&E data response to ORA DR 252, Q. 1

2003 plant estimates by removing the expenditures and additions forecasted for MWC 91.

IV. DISCUSSION/ANALYSIS—2003 EXPENDITURES AND PLANT ADDITIONS

PG&E is requesting a total of $190.7 million in expenditures and additions for gas distribution plant in 2003. PG&E's 2003 request is $10.6 million and $12.3 million above its 2002 recorded expenditures and additions, respectively. PG&E's request is broken down by the following MWCs: 14, 27, 29, 47, 50, 51, 52, 74 and 91. ORA's analysis and recommendations regarding each of these MWCs are discussed below.

A. MWC 14, GAS PIPELINE REPLACEMENT PROGRAM

MWC 14 includes all capital expenditures related to replacing aging pipe under PG&E's Gas Pipeline Replacement Program (GPRP). The GRRP was established in 1985. The program's scope is to replace all cast iron and most pre-1931 steel distribution mains and some transmission pipelines as well. In addition to gas main replacement, PG&E also replaced services and performs meter relocation work at the same time and expenditures are recorded in MWC 14.[18]

PG&E is requesting $67.9 million in capital expenditures to perform GPRP work in 2003. PG&E's unit of measurement for this MWC is the feet of main installed and the number of miles of main retired or deactivated. PG&E's 2002 forecast shows a unit cost of $210.35 per foot of main installed, (or $1.1 million per mile) for 315,418 feet and $1,169,145 per mile of mains retired for 56.75 miles. PG&E's 2002 forecast includes an

[18] PG&E-2, p. 13-55.

increase of work concentrated in San Francisco. PG&E's workload mix shows 37% of San Francisco GPRP work in 2002.

PG&E's data response to ORA's data requests show that through November 2002, PG&E installed 53.64 miles and deactivated 20.72 miles in GPRP work throughout its territory. PG&E informed ORA that all remaining GPRP projects were on track for completion as forecasted.[19] PG&E's 2002 actual expenditures and additions for MWC 14 were $63.2 million and $67.7 million, respectively.

PG&E's 2003 forecast of expenditures for MWC is $67.9 million. PG&E's workload mix shows an increase in San Francisco GPRP work over the 2002 level from 37% to 43%. According to the 2001 Annual Progress Report filed with the Commission, which tracks the GPRP's progress, San Francisco has 206 miles, or 78%, of the remaining cast iron pipe. PG&E states that 60 % of the remaining GPRP distribution pipes exist in four PG&E divisions: San Francisco (37%), Sacramento (9%), North Coast (7%) and East Bay (7%). The GPRP Annual Progress Report also shows that of the total 762 miles of distribution main PG&E plans to retire between 2002 and 2009, 263 miles are cast iron and 499 miles are steel. Between 1985 and 2001, PG&E retired a total of 1,211 miles of main. Of the total number of miles retired, 573 miles were cast iron and 638 miles were steel.

PG&E's 6 year average of plant expenditures from 1997 through 2002 shows that PG&E spent $66.112 million in expenditures and $61.340 in additions for this MWC. ORA finds PG&E's forecast of $67.9 million to be reasonable and expects that PG&E's 2003 goals for the GPRP will be met.

[19] PG&E data response to ORA DR 172, Q.1.

B. MWC 27, METER PROTECTION PROGRAM

MWC 27 includes work and materials necessary to correct gas meter locations that do not conform to current standards. Activities associated with this MWC include replacing and relocating a gas service in order to relocate the meter to a safe location. Historical expenditures and additions for this MWC between the years 1997 and 2002 are presented in Table 16-5 below.

Table 16-5
MWC 27, METER PROTECTION PROGRAM
RECORDED CAPITAL EXPENDITURES & ADDITIONS
(In Thousands of Nominal Dollars)

1997	1998	1999	2000	2001	2002	6 year Avg.
Expenditures						
1,991	1,130	119	581	478	420	786
Additions						
2,457	1,147	107	465	376	576	854

PG&E's 2003 request of $700,000 in capital expenditures and additions for this MWC appears to be reasonable. ORA accepts PG&E's 2003 forecast for this MWC.

C. MWC 29, GAS DISTRIBUTION CUSTOMER CONNECTS

MWC 29 includes expenditures for building new gas underground distribution systems to provide service to new customers, including the associated services and regulation and metering equipment. This MWC also includes the costs of regulators purchased for such purposes as emergency response, regulator change out and system upgrades.

PG&E is requesting $61.3 million in capital expenditures in 2003. This expenditure amount is for 40,000 customer connections (37,000

residential and 3,000 non residential), customer refundable advances, regulators, and betterment.

PG&E's workpapers show that while PG&E's forecasts 40,840 connections for 2002 and 40,000 connections for 2003, the expenditures for 2003 is higher than 2002 even though the number of connections are lower and 2002 expenditures included a one time charge of $9.1 million for the pre-bankruptcy new customer connect contracts.[20] The workpapers also show that PG&E allocated different amounts for "G15R1" and "G15R5" residential, "Standard", and "50% option" non-residential connections under allowance per connect for year 2002 and 2003 while citing the same tariff options.[21]

PG&E's 2002 actual expenditures for MWC 29 were $59.7 million. This total included a <u>one-time</u> accrual of $9.1 million in September 2002 associated with expenditures to be reimbursed to customers as part of the March 25, 2002 Bankruptcy Court order. According to PG&E, this order requires PG&E to reimburse its customers for performing work that is the responsibility of PG&E. The $9.1 million was accrued into CWIP to be added to plant in service as customer payments are made through 2002 and into 2003 for dispute resolution.[22] PG&E informed ORA that as of January 01, 2003, there is $3.1 million left (that had not been booked to plant) of the original $9.1 million reimbursement amount that PG&E plans to pay customers for dispute resolutions in 2003.

PG&E provided inadequate substantiation for the increase in 2003 expenditures for approximately the same number of customer connections

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[20] PG&E-2, P. 3-27.

[21] At the time of ORA's filing, PG&E has not responded to data requests regarding the differences in PG&E's tariff allocations for 2002 and 2003.

[22] PG&E data response to ORA DR 252, Q 1.

forecasted for 2003 as 2002. PG&E's 2002 actual expenditures were $50.6 million, net the one time accrual of $9.1 million, for an estimated 40,840 connections in 2002. Additionally, PG&E's 2003 request is unjustified because it includes $1 million for gas "betterment" work. Gas "betterment" usually involves the installation of larger diameter gas main to serve future development.[23] In 2002, PG&E's recorded expenditures for gas "betterment" were $13,835 although the company had also forecasted $1 million for "betterment". PG&E informed ORA that it has not specifically identified any gas betterment work for 2003.[24]

ORA estimates 2003 expenditures for new customer connections in MWC 29 to be consistent with 2002 actual expenditures of $50.6 million, less $1 million because PG&E has not identified any "betterment" work for 2003. ORA acknowledges that there is $3.1 million remaining balance (of the $9.1 million) accrued in CWIP to be disbursed as dispute resolution and added to plant in service in 2003. For all the reasons stated above, ORA recommends the adoption of $52.7 million as the adjusted 2003 forecast for MWC 29.

D. MWC 47, GAS DISTRIBUTION NEW CAPACITY

MWC 47 tracks expenditures of work and materials required to install facilities needed to meet load growth. Activities in MWC 47 include installing mains parallel to existing mains, replacing existing mains with larger diameter and/or higher pressure mains, adding new regulator stations, and installing mains to interconnect existing systems.[25]

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[23] PG&E-2, p. 3-26.

[24] PG&E data response to ORA DR 269, Q. 2.

[25] PG&E-2, p. 13-49.

PG&E is requesting $4.2 million in capital expenditures for MWC 47. PG&E's recorded expenditures for 2000, 2001, and 2002 were $3.3 million, $3.7 million, and $3.3 million, respectively.

PG&E's calculation of total expenditures is based on the unit cost for feet of main installed, regulator stations installed, and regulators replaced. PG&E forecasts that in 2003, the company will install 52,000 feet of mains and 22 regulator stations, while replacing 14 regulator stations in its system. The level of work forecasted for 2003 is consistent with 2002. For 2002, PG&E forecasted installing 49,500 feet of mains and 24 regulators and replacing 14 regulators in its system.

For 2003, PG&E simply states that the company is requesting $4.2 million to ensure adequate capacity of the gas system. Since the expenditures in this MWC have remained flat for the past 6 years, ORA finds PG&E's request for an increase of $700,000 above the average expenditure level to be unsubstantiated. ORA recommends an adjustment to PG&E's 2003 forecast to reflect recent and historical recorded levels of expenditures in this MWC. ORA's 2003 forecast of $3.5 million, which is $700,000 less than PG&E's 2003 forecast, for this MWC is based on a 6-year average of historical expenditures for the years 1997-2002. ORA's estimate is above 2002 recorded expenditures for this MWC. ORA's 2003 forecast for MWC 47 is $3.5 million is also comparable to recent historical expenditures for this MWC. See Table 16-6 below for a summary of PG&E's historical and forecast expenditures and ORA's 2003 forecast.

Table 16-6
MWC 47, CAPITAL EXPENDITURES
(In Thousands of Nominal Dollars)

							PG&E	ORA
Recorded							Forecast	Forecast
1997	1998	1999	2000	2001	2002	6-year Avg.	2003	2003
3,636	3,961	3,249	3,329	3,726	3,260	3,527	4,240	3,540

E. MWC 50, GAS RELIABILITY

MWC 50 tracks expenditures for work and materials necessary to install equipment and facilities to improve system reliability and replace those aging facilities that are not part of the GPRP.

PG&E is requesting $16 million in capital expenditures for MWC 50 in 2003. The expenditures are spread among work done in general for reliability, low-pressure station upgrades, and cathodic protection remote monitoring. PG&E's request appears to be reasonable, with the exception of expenditures for the cathodic protection remote monitoring project.

ORA recommends that $1.2 million be excluded from the 2003 forecast because PG&E does not expect the CP remote monitoring units to be operative until December 31, 2003.[26] This adjustment results in a 2003 forecast of $14.8 million by ORA in contrast to $16 million that PG&E had forecasted for this MWC.

F. MWC 51, Gas Work at the Request of Others

MWC 51 tracks expenditures for relocating gas distribution facilities at the request of a governmental agency or other third parties (e.g., customers and developers). Work in this MWC is driven by customer

[26] PG&E data response to ORA DR 105, Q.5.

requests and often depends on funding available to governmental agencies for road widening or other infrastructure improvements.[27]

PG&E's 2002 and 2003 forecasts for MWC 51 are identical, with $18 million in expenditures for each year. This forecast is derived by using the average annual expenditures between 1997 and 2001. According to PG&E, work associated with cities and counties tends to be fairly constant.[28]

ORA agrees with PG&E's assertion that work associated with cities and counties tends to be fairly constant. ORA recommends adopting PG&E's 2002 actual record expenditures of $17 million as 2003 expenditures for MWC 51. With the State of California facing a budget crisis of $11 billion[29] the amounts of funding available to government agencies will likely be affected in 2003. Therefore, ORA expects expenditures for 2003 to be consistent with 2002 levels. ORA believes that adopting the 2002 actual expenditures of $17 million for 2003 results in a reasonable forecast. ORA recommends an adjustment of $1 million to MWC 51 bringing the 2003 forecast down to $17 million in contrast to the $18 million PG&E forecasted.

G. <u>MWC 52, Gas Emergency Response</u>

MWC 52 incorporate expenditures for work and materials required to replace damaged or failed facilities, and includes capital replacement of mains and services due to gas dig-ins, natural disasters such as landslide and any other emergency capital replacements.

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[27] PG&E-2, p. 3-33.

[28] PG&E-2, p. 3-33.

[29] "*Hole Gets Deeper by Billions*," LA Times, March 6, 2003.

PG&E is requesting $200,000 in expenditures for this MWC in 2003. This is the same amount that PG&E forecasted for 2002. PG&E's 2002 actual expenditures for this MWC were $132,000.

ORA finds PG&E's 2003 request to be reasonable. ORA accepts PG&E's 2003 forecast in expenditures and additions for this MWC.

H. MWC 74, GAS METERS

MWC 74 tracks expenditures for meter purchases, new meter installation labor costs, and load research programs. In addition, MWC 74 covers the field labor portion of the GPRP. PG&E expects to purchase a higher number of meters in 2002 and 2003 compared to 2001. This is because PG&E buys new meters to serve its expanding customer base and to replace meters which are removed in the field and are not cost-effective to repair.[30]

PG&E is requesting $22.4 million in capital expenditures for 2003. This total includes expenditures for gas meter purchases, capitalized gas meter installation, the gas regulator replacement program (GRRP), gas load research, and gas meter PLC replacement project. In 2002, PG&E recorded a total of $19.6 million in expenditures for MWC 74.

ORA disagrees with PG&E's increase as reflected in the 2003 forecast. PG&E presented the total gas metering costs, both capital and expense, per unit of in-service meter in Table 70-7 of Exhibit PG&E-2. PG&E requests an increase of $1 per unit of in service gas meters and attributed this increase to the 56,000 electronic remote transmitting (ERT) devices that PG&E plans to install on gas meters during 2003 and 2004, with about 50 % being installed each year. This translates to PG&E installing

[30] PG&E-2, p. 10-7.

28,000 ERT devices in 2003 at $60 per unit with a total cost of $1.7 million. With a forecast of 3,986,658 gas meters in service in 2003, the impact on unit cost per gas meter should be an increase of $0.42 per meter.

ORA previously discussed this issue in Chapter 7, Gas Distribution O&M Expenses. ORA agrees with PG&E's 2002 forecast of $8.42 per meter and recommends an increase of $0.42 to the 2002 expenses to arrive at $8.84 (and not $9.42) per gas meter for 2003. This translates to a total adjustment of $2.304 million, which brings the new total amount for gas metering to $35.2 million rather than the $37.5 million that PG&E had forecasted for 2003. Of the total adjustment, 48% or $1.2 million was adjusted from the expenses in MWC EY, as previously discussed in Chapter 7, Gas Distribution O&M Expenses. The remaining 52% or $1.3 million should be adjusted from MWC 74 for gas metering purchases and installation labor.

ORA also recommends an adjustment in the annual expenditures for the GRRP which are included in this MWC. This component of the GRRP program was created by PG&E in June 1984 as a seven-year program to locate and replace all ¾ -inch domestic non-Internal Relief Valve (IRV) gas regulators with new IRV regulators. The program is still in existence. PG&E has performed several "re-surveys" of regulator locations to determine the locations of non-IRV regulators for replacement, with the latest survey done in 1999. Moreover, PG&E has been installing only IRV regulators since 1981. 2001 was the latest year that PG&E was able to provide recorded expenditures for the GRRP and the recorded amount was $1.2 million.[31] ORA recommends an additional adjustment of $947,000 to

[31] PG&E-2, p. 10-9.

PG&E's 2003 forecast for the GRRP to more closely reflect actual expenditure levels.

ORA recommends the overall decrease of $2.2 million in expenditures for MWC 74, so that the total capital expenditures and additions for MWC 74 is $ 20.2 million in contrast to the $22.4 million that PG&E forecasted for 2003.This figure is slightly above the $19.6 million in expenditures incurred for this MWC in 2002.

V. CONCLUSIONS

ORA finds PG&E's 2002 recorded capital expenditures, additions and retirements to be reasonable and recommends that the Commission adopts these expenditures to PG&E's gas distribution plant. ORA also recommends that the Commission adopt the ORA forecast of 2003 capital additions in the amount of $170.4 million rather than PG&E's forecast of $190.7 million. Additionally, ORA recommends the adoption of $5.349 billion[32] as the 2003 WAVG gas distribution plant with $74.3 million in WAVG net functional plant additions. ORA's forecast is more appropriate because it incorporates 2002 recorded plant additions and removes $6.7 million in Cost of Removal expenditures inappropriately included in PG&E's 2003 gas distribution functional plant forecast. ORA's 2003 forecast is also more reasonable because it reflects historical as well as recent actual expenditure levels. Additionally, ORA recommends using a weighting average percentage of 48.57% to develop the WAVG plant additions in 2003 to reflect the average over the past 6 years. ORA finds that using the average percentage of WAVG plant additions in deriving the 2003 forecast is a fair and equitable

[32] This amount includes an illustrative Common Plant amount (PG&E's 2003 forecast for Gas Distribution Common plant) and will be adjusted accordingly if ORA's witnesses for Common Plant and Common Plant Allocations determine that a different amount is more reasonable for Gas Distribution Plant.

approach because this weighting percentage more accurately reflects gas distribution plant activities for the past 6 years.

CHAPTER 17

DEPRECIATION EXPENSE AND RESERVE

I. INTRODUCTION

This chapter presents the analyses and recommendations of ORA regarding Depreciation Expense and Reserve for PG&E's electric and gas distribution systems for the 2003 test year. The company sets forth its request in Chapters 9 (Depreciation Reserve and Expense) and 10 (Depreciation Study) of Exhibit PG&E-6 (Distribution Results of Operation). The majority of this chapter is devoted to discussing and analyzing depreciation expense; the depreciation reserve will automatically be adjusted by the Results of Operations (RO) computer model to reflect any changes to depreciation expense.

Sections II through IV of this chapter discuss general issues that pertain to both the electric and gas distribution systems—Section II summarizes the differences between ORA's and PG&E's recommendations, Section III presents ORA's analyses of PG&E's requests and support for ORA's forecasts and adjustments, and Section IV provides ORA's conclusions. This chapter also includes two appendices that demonstrate that the net salvage costs currently being recovered from ratepayers are greater than PG&E's actual expenditures. These appendices also include account-by-account recommendations regarding net salvage percentages.

II. SUMMARY/RECOMMENDATIONS

In its Test Year 2003 General Rate Case (GRC) application, PG&E forecasts electric distribution depreciation expense levels of $564.7 million, a 49.4 percent <u>increase</u> over the $377.9 million level adopted in PG&E's last GRC decision (D.00-02-046). PG&E also forecasts gas distribution depreciation expense levels of

$179.4 million, a 15.1 percent reduction to the $211.3 million adopted previously. In addition, PG&E is requesting $5,978.6 million for its 2003 electric distribution-related depreciation reserve, and $3,071.7 million for gas distribution-related depreciation reserve.

ORA's estimates for electric and gas distribution depreciation expense and reserve differ from PG&E's estimates for three reasons:

1. ORA had access to recorded 2002 data. Unlike PG&E, which had to estimate capital additions (which directly impact depreciation expense levels), depreciation expense, and reserve amounts for 2002, ORA incorporated recorded data into the RO model. Those recorded amounts were used by the RO computer model to calculate updated depreciation expense levels.
2. ORA is proposing to make a number of adjustments to PG&E's proposed Test Year capital additions. Reduced capital expenditures directly translate into reduced depreciation expense estimates, and hence into decreased levels of depreciation reserve. Details of ORA's proposed capital adjustments are discussed in other chapters of this report, and are not repeated here.
3. As will be discussed at greater length later in this chapter, ORA does not agree with PG&E's proposed changes to the net salvage percentages it uses for its electric distribution system. PG&E's proposed net salvage changes result in higher depreciation expense estimates; those changes are largely due to PG&E increasing its estimates of the costs of removing existing capital items. ORA questions the way PG&E has derived its electric distribution net salvage percentages. ORA is recommending that net salvage percentages for electric distribution remain at the levels adopted by this Commission in the last PG&E GRC decision.

Table 17-1 presents the recommendations of ORA and PG&E for Depreciation Expense and Weighted Average Depreciation Reserve for Test Year 2003; it also shows the differences between the respective estimates.

Table 17-1

DEPRECIATION EXPENSE & RESERVE

TEST YEAR 2003

(Dollars in millions)

	ORA	PG&E	PG&E > ORA	%
Electric				
Depreciation Expense	$460.0	$564.7	$104.7	22.7%
Weighted Avg. Depr. Reserve	$5,924.1	$5,978.6	$54.5	0.9%
Gas				
Depreciation Expense	$175.3	$179.4	$4.1	2.3%
Weighted Avg. Depr. Reserve	$3,082.3	$3,071.7	($10.6)	(0.3%)

III. DISCUSSION/ANALYSIS

The purpose of depreciation is to allow a utility to recover the original cost (less net salvage) of its investment in tangible capital assets over the useful lives of the assets. At its most basic level, depreciation expense is dependent on three factors: the amount of capital expenditures, the expected service lives of the capital items, and the expected amount of net salvage that will be received when the capital items reach the end of their useful lives. Depreciation calculations are made on a straight-line-remaining-life basis using rates generally calculated in accordance with CPUC Standard Practice U-4.

PG&E's plant is grouped into various accounts or asset classes. The depreciation rates PG&E is using in this application are based on a new depreciation study that proposes changes to the service lives and net salvage rates of various asset classes. PG&E is requesting that the Commission adopt its 2003 forecast of $564.7 million for depreciation expense for electric distribution plant, and $179.4 million for depreciation expense for gas distribution plant. These

expense levels represent an increase of $186.8 million over existing authorized rates for electric, and a decrease of $31.9 million for gas.[1] The following table provides a further breakdown on the causes of these proposed increases:

Table 17-2

PG&E'S PROPOSED DEPRECIATION INCREASES[2]

TEST YEAR 2003

(Dollars in millions)

	Due To Plant Growth	Due To Changed Service Lives	Due To Net Salvage Changes	Total Increase (Decrease)
Electric Depr. Expense Increase	$66.8	$22.4	$97.6	$186.8
Gas Depr. Expense Increase	$27.6	($38.9)	($20.6)	($31.9)

In its analyses of these proposed depreciation expense increases, ORA has concentrated on the changes due to plant growth and the changes due to net salvage differences. Because of staffing/timing constraints, and because the dollar impacts are not as large as the other two areas, ORA spent little time analyzing PG&E's proposed changes to the service lives. ORA is not recommending any changes to PG&E's proposed changes to service lives. The remainder of this section discusses ORA's recommendations concerning depreciation increases due to plant growth and net salvage changes.

A. <u>ORA's Use of Recorded 2002 Data</u>

When PG&E prepared its estimates for this application, it did not have access to recorded 2002 data. As a result, PG&E's exhibits and workpapers contain estimates for 2002 plant additions, depreciation expense, and depreciation reserves. Since depreciation expense calculations are based

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[1] PG&E-6, p. 9-1 and 9-2.

[2] PG&E data response to ORA DR 207, Q. 1 and 2.

on plant-in-service balances, it is important to use the most current plant data available.

Plant balances are cumulative in nature; additions during a year are added to that year's beginning-of-year (BOY) plant balance. Therefore, the last (most recently) recorded BOY plant balance serves as the "starting point" to which all future estimates for capital expenditures are added. Because of access to recorded 2002 data, the "starting point" for ORA is the recorded 2003 BOY balance. For PG&E, this "starting point" is the recorded 2002 BOY balance; it then needs to add its estimates for 2002 capital additions to derive its estimate for the 2003 BOY balance. At ORA's request, PG&E updated its RO computer model to include 2002 recorded data.

Without doing a separate computer analysis (where all inputs are held constant except for the updated 2002 plant data), ORA cannot compute the exact impact this recorded plant will have on depreciation expense. ORA's RO computer model is being run once, with all of ORA's proposed adjustments included. Whether recorded 2002 plant balances are higher or lower than the estimated balances, the RO computer model will recalculate depreciation expense using these new plant balances, with a corresponding adjustment flowing to the depreciation reserve.

B. <u>Adjustments To Test Year 2003 Capital Additions</u>

As part of its investigation of PG&E's GRC application, ORA is analyzing PG&E's proposed capital additions for electric and gas distribution plant, as well as common, general, and intangible plant. The results of ORA's capital analyses can be found in Chapters 14 (Electric), 15 (Common, General, and Intangible), and 16 (Gas) of this report.

As was discussed in the previous section, depreciation expenses are based on plant balances. Therefore, any capital adjustments proposed by ORA will impact the calculation of depreciation expenses. All of ORA's recommended capital adjustments are incorporated into the RO computer model. Without preparing a special RO run (with only ORA's proposed capital adjustments being included in the model), the exact impact on depreciation expense of the recommended adjustments cannot be determined. However, since ORA's proposed capital adjustments result in lower 2003 plant balances, it follows that depreciation expenses will be reduced, with a corresponding reduction flowing to the depreciation reserve.

C. <u>Net Salvage Adjustments</u>

Net salvage is made up of two components: the gross salvage (which is the total amount the utility receives when it sells a plant item), and the cost of removal (which are the costs that are incurred when the utility removes the plant that is being retired). Net salvage can be either positive or negative, depending on whether the gross salvage or the cost of removal is greater. Positive net salvage reduces depreciation expense, while negative net salvage increases it.

Whether net salvage is positive or negative is of great importance in determining the levels of depreciation expense. As noted previously, the purpose of depreciation is to recover the original cost of a utility's capital investment. Therefore, if a positive net salvage of 10% exists, the utility is only required to recover 90% of its original investment through depreciation expense, with the remaining 10% being obtained when the capital item is sold. Alternatively, if the net salvage is a negative 10%, then depreciation expense must recover 110% of the original investment, the extra 10% being necessary to cover the cost of removal of the capital item.

As Table 17-2 shows, net salvage changes are responsible for the majority of the depreciation expense changes. Unfortunately, net salvage adjustments are very volatile and unpredictable, with estimates changing dramatically from one rate case to another. A good example of this is Account 380, a gas account that includes the cost of pipes, services, and accessories leading to a customer's premises. As discussed on pages 358 and 359 of the last PG&E GRC decision (D.00-02-046), PG&E was proposing to change the then-authorized net salvage percentage of negative 120% to an even more negative value of negative 350%. As the decision points out, that one change would have resulted in ratepayers paying $3.4 billion more in depreciation expense over the life of the investment.

In this current GRC, PG&E states that 3-year moving averages of net salvage for Account 380 vary from negative 64% to negative 1253%, a considerable range.[3] In this current application, PG&E is requesting that the net salvage percentage for Account 380 be changed to negative 85%, a less negative (closer to zero) amount than the negative 120% figure that is currently authorized and that PG&E sought to change in the previous GRC. In hindsight, ratepayers are extremely fortunate that the Commission declined to grant PG&E's requested net salvage change in the last GRC. Had PG&E's request been granted for Account 380, for the last four years (1999 through 2002), ratepayers would have been paying gas depreciation expenses based on a net salvage of negative 350%, a percentage that PG&E now believes should be negative 85%. Changing the net salvage from negative 120% to negative 350% would have resulted in an additional depreciation expense (for this single gas account) of over $120 million[4]

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[3] Workpapers to PG&E-6, Chapter 10, p.10-225.

[4] Prepared Testimony of Jacob Pous, A.97-12-020, p. 7.

more per year; this would have caused ratepayers to pay more than $480 million in additional depreciation expense over the four year period.

Because of their apparent unpredictability and because they cause the majority of the changes listed in Table 17-2, it is clear that net salvage percentages must be analyzed carefully. As part of its investigation, ORA studied PG&E's net salvage workpapers, issued data requests, and reviewed the net salvage issues that were of concern in the last GRC. In performing its analysis of net salvage, PG&E looked at recorded plant retirements, gross salvage amounts, and cost of removal figures for the period 1969 through 1999. For each of those years, PG&E calculated gross salvage and cost of removal as a percentage of the plant that was retired during the year. Those values were then combined into a net salvage percentage. To smooth the yearly fluctuations in the data, PG&E generated three-year and five-year moving averages over the entire study period. Utilizing the trends of these moving averages, and combining them with interviews with field personnel and industry comparisons, PG&E used judgment to estimate an appropriate net salvage percentage for each asset class.

ORA questions whether the recorded net salvage data that PG&E relied on as part of its judgment process included all of the salvage dollars that were actually received. ORA is concerned that reimbursed retirement dollars (which are defined in the next paragraph) were not included in the recorded net salvage. It appears that PG&E still uses the same methodology it employed in the last GRC—PG&E continues to credit reimbursed retirements to the cost of replacement, rather than including it with the net salvage.

In general, reimbursed retirements are dollars received by PG&E from outside parties when unexpected retirements occur that result in compensation. As an example, a utility may receive compensation from

insurance companies if a storm knocks over power poles and downs power lines. As another example, PG&E may seek compensation from a driver if that driver hits and breaks a power pole. As a third example, PG&E may receive compensation from governmental agencies if those agencies require PG&E to relocate facilities, perhaps due to road widening. In both the last GRC and this current application, PG&E recorded the amounts received from reimbursed retirements as a reduction to the cost of the new replacement item, rather than including it as part of the net salvage. In response to an ORA data request, PG&E stated that reimbursed retirements are considered as contributions in aid of construction, thereby lowering the cost of the replacement project.[5] ORA believes that this practice lowers net salvage estimates, increasing the amount of depreciation expense. As an example, suppose that for a given class of plant for a given year, the recorded retirements were $1000 and the recorded net salvage was negative $150 (meaning that the cost of removal exceeded the gross salvage by $150, a common occurrence). Let's further suppose that PG&E received $200 in reimbursed retirements that it applied to the cost of the new plant that is replacing the old plant that is being retired. Using PG&E's methodology, the recorded net salvage percentage would be a negative 15% (negative $150 in net salvage divided by $1000 in retirements). A more appropriate method of making this calculation would be to remove the $200 in reimbursed retirements that PG&E had credited to the replacement project, and instead, add it to the net salvage. Therefore, the net salvage is increased by $200, going from a negative $150 to a positive $50. This results in a net salvage percentage of 5% ($50 in net salvage divided by $1000 in retirements). This

[5] PG&E data response to ORA DR 207, Q. 3a.

simple change in booking reimbursed retirements causes the net salvage percentage to shift form a negative 15% to a positive 5%.

ORA requested that PG&E recalculate its net salvage amounts by including reimbursed retirements; PG&E responded that it could not do so.[6] Absent that information, it is impossible to know precisely how much the net salvage percentages would change if the reimbursed retirements were shifted to net salvage. However, as the above example illustrates, shifting reimbursed retirements will cause the net salvage percentages to increase (positive percentages will get larger; negative percentages will move closer to zero or go positive). In the last PG&E GRC, TURN raised this same issue, pointing out that ratepayers benefit when reimbursed retirements are included in net salvage.[7] It should also be noted that when calculating its net salvage percentages, Southern California Edison includes reimbursed retirements in with the net salvage.

ORA believes that special attention should be paid to the Commission's discussion of depreciation in the last PG&E GRC. On page 359 of that decision, the Commission stated:

> "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

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[6] PG&E data response to ORA DR 207, Q. 4b.

[7] Prepared Testimony of Jacob Pous, A. 97-12-020, pp. 30 through 32.

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."

ORA does not believe that PG&E has presented "compelling reasons" for changing its electric distribution net salvage levels. On the contrary, there are "compelling reasons" for keeping net salvage percentages at their currently authorized levels, or even increasing them (making positive percentages larger, and/or making negative percentages closer to zero or positive). As will be discussed in Appendices A and B, PG&E is currently receiving in rates more net salvage dollars than it is actually spending; this is especially true for gas distribution. ORA's analysis of how reimbursed retirements are booked, the prior testimony of TURN's depreciation witness on the reimbursed retirements issue, and the practice of Southern California Edison to include reimbursed retirements in its net salvage data, all call into question the validity of the recorded net salvage data that PG&E relied on to help form its judgment regarding net salvage changes. Additionally, a comparison of the recorded net salvage dollars actually received and the net salvage dollars actually spent reveals that PG&E is accruing much more than it is spending. This causes ORA to question the reasonableness of PG&E's requested net salvage changes for electric distribution, which, if adopted, would further increase the net salvage amounts paid by ratepayers. Since the validity of the recorded data relied upon by PG&E is questionable, and since the need for additional net salvage dollars has not been shown, ORA recommends that PG&E's proposed changes to net salvage percentages for electric distribution be denied. Instead, ORA recommends that net salvage percentages for electric distribution be kept at the levels currently authorized (per D.00-02-046).

It should be pointed out that the net salvage percentages used in the currently authorized electric distribution depreciation rates likely have excluded reimbursed retirements. Therefore, it is possible that even the currently authorized percentages should be changed so that ratepayers are paying less. However, absent a detailed reexamination of the currently authorized electric distribution depreciation rates to see how reimbursed retirements are handled, ORA believes that the net salvage percentages currently included in the adopted depreciation rates should continue to be used.

For gas distribution plant, PG&E's own proposed adjustments to net salvage percentages result in the overall net salvage amounts paid by ratepayers decreasing in comparison to the level currently authorized. ORA agrees with the direction PG&E's proposed net salvage levels are heading. As will be discussed in Appendix B, currently authorized net salvage rates provide far more net salvage dollars than are actually spent. Therefore, even the net salvage percentages included in the currently authorized gas distribution depreciation rates result in too much money being paid by ratepayers. Because PG&E's proposed changes to net salvage percentages cause the overall net salvage levels paid by ratepayers to decrease, ORA recommends that the proposed changes be adopted.

V. CONCLUSIONS

The burden is on PG&E to persuasively show that the requested changes to the net salvage percentages are reasonable and appropriate. Page 359 of PG&E's last GRC decision (D.00-02-046) states that changes to authorized depreciation parameters will be made only when there are "compelling reasons" to do so. For electric distribution, PG&E has failed to provide "compelling reasons" for requesting changes to net salvage percentages that would result in increased costs

for ratepayers. ORA's investigation of the general methodology used to develop net salvage, the analysis of how reimbursed retirements are booked, the prior testimony of TURN's depreciation witness on the reimbursed retirements issue, the practice of Southern California Edison to include reimbursed retirements in its net salvage data, and an examination of recorded net salvage dollars actually received/spent by PG&E, all suggest that PG&E's proposed net salvage changes are not reasonable. ORA recommends that for electric distribution plant, the net salvage percentages should remain at their currently authorized levels.

For gas distribution plant, PG&E is proposing changes to the currently authorized net salvage percentages that would cause the amount of net salvage dollars received by PG&E to decrease. Based on the data contained in Table 17-5 in Appendix B, ORA agrees that the net salvage dollars received by PG&E should be lower than the currently authorized levels. Therefore, ORA recommends that PG&E's proposed changes to the current net salvage percentages for gas distribution be adopted.

ORA recommends that its depreciation expense and weighted average depreciation reserve amounts contained in Table 17-1 be adopted.

APPENDIX A – ELECTRIC

ORA is recommending that PG&E's proposed changes to electric distribution net salvage percentages be denied. Instead, ORA recommends that net salvage percentages be kept at the levels currently authorized by the Commission (per D.00-02-046). Earlier sections of this chapter have discussed why ORA believes PG&E has failed to provide "compelling reasons" for changing these percentages. As a check of the reasonableness of this recommendation, ORA wanted to answer the fundamental question, "Do current electric distribution depreciation rates include net salvage percentages at a level sufficient for PG&E to cover ongoing net salvage costs?" Table 17-3 shows that the answer to that question is "Yes."

Table 17-3

NET SALVAGE DOLLARS RECEIVED VS. ACTUALLY SPENT[8]

TEST YEAR 2003

(Dollars in thousands)

	1993	1994	1995	1996	1997	1998
Net Salvage Received In Rates						
Electric Distribution	$84,450	$89,808	$94,834	$66,308	$71,564	$77,121
Net Salvage Actually Spent						
Electric Distribution	($2,046)	$9,517	$8,760	$1,578	$39,505	$22,250

(Continued)	1999	2000	2001	2002	Total
Net Salvage Received In Rates					
Electric Distribution	$82,142	$86,169	$91,361	$96,771	$840,528
Net Salvage Actually Spent					
Electric Distribution	$20,353	$21,439	$29,463	$43,652	$194,471

[8] PG&E data response to ORA DR 266, Q. 2. Note that net salvage amounts associated with allocated plant (Common, General, etc.) have been excluded from both the "Received In Rates" and "Actually Spent" lines. Those amounts are small in comparison, and will not impact the conclusion that PG&E is receiving far more net salvage dollars than it is actually spending.

As Table 17-3 clearly indicates, both on a yearly basis and on a cumulative basis over the past 10 years, PG&E is accruing net salvage dollars in rates well above actual expenditures. The data in this table leads to the obvious conclusion that PG&E's proposed changes to net salvage percentages, which would cause the net salvage dollars received in rates to increase, are not reasonable. Currently authorized depreciation rates already generate a sufficient accrual of net salvage dollars for PG&E. ORA can see no reason for changing the net salvage percentages and generating even greater surpluses. Table 17-4 (on the next page) provides an account-by-account listing of the electric net salvage percentages being recommended by PG&E and ORA.

Table 17-4

ELECTRIC NET SALVAGE RECOMMENDATIONS BY FERC ACCOUNT

TEST YEAR 2003

Asset Class	FERC Account	Currently Authorized	PG&E Proposed	ORA Recommended (Same as Currently Authorized)
Electric Transmission				
Structures & Improvements	352	-10%	-10%	-10%
Structures & Improvements/Equip	352	-5%	-10%	-5%
Station Equipment	353	0%	-30%	0%
Step Up Transformers	353	0%	0%	0%
Towers & Fixtures	354	-40%	-50%	-40%
Poles & Fixtures	355	-50%	-100%	-50%
OH Conductor/Devices	356	-31%	-100%	-31%
UG Conduit	357	0%	0%	0%
UG Conductor/Devices	358	0%	0%	0%
Roads & Trails	359	0%	0%	0%
Electric Distribution				
Structures & Improvements	361	-10%	-20%	-10%
Structures & Improvements/Equip	361	0%	-20%	0%
Station Equipment	362	0%	-20%	0%
Storage Battery	363	0%	0%	0%
Poles, Towers, & Fixtures	364	-35%	-80%	-35%
OH Conductor/Devices	365	-49%	-100%	-49%
Underground Conduit	366	10%	-30%	10%
UG Conductor/Devices	367	-19%	-30%	-19%
Line Transformers - Overhead	368	10%	5%	10%
Line Transformers - Underground	368	0%	2%	0%
Services - Overhead	369	-60%	-60%	-60%
Services - Underground	369	-40%	-35%	-40%
Meters	370	0%	0%	0%
Installation on Customer Premises	371	0%	0%	0%
Leased Property on Customer Premises	372	75%	75%	75%
Street Light - Overhead Conductors	373	-95%	-50%	-95%
Street Light - Conduit & Cables	373	-10%	-10%	-10%
Street Light - Lamps & Equipment	373	-10%	0%	-10%
Street Light - Electroliers	373	0%	-5%	0%
Electric General				
Structures & Improve - Office	390	2%	2%	2%
Office Furniture & Equipment	391	20%	20%	20%
Shop Equipment	394	10%	10%	10%
Laboratory Equipment	395	0%	0%	0%
Power Operated Equipment	396	10%	10%	10%
Communication Equipment	397	-4%	-4%	-4%
Miscellaneous Equipment	398	20%	20%	20%

APPENDIX B – GAS

ORA is recommending that PG&E's proposed changes to gas distribution net salvage percentages be adopted. ORA agrees with PG&E that the net salvage percentages currently included in the adopted gas distribution depreciation rates must be changed so that net salvage dollars currently received in rates is lowered. A look at Table 17-5 reveals why this is so.

Table 17-5

NET SALVAGE DOLLARS RECEIVED VS. ACTUALLY SPENT[9]

TEST YEAR 2003

(Dollars in thousands)

	1993	1994	1995	1996	1997	1998
Net Salvage Received In Rates						
Gas Distribution	$91,798	$98,214	$104,621	$87,616	$93,229	$97,427
Net Salvage Actually Spent						
Gas Distribution	$4,690	$2,646	$2,457	$4,291	$8,304	$4,979

(Continued)	1999	2000	2001	2002	Total
Net Salvage Received In Rates					
Gas Distribution	$100,774	$104,835	$110,096	$115,831	$1,004,441
Net Salvage Actually Spent					
Gas Distribution	$6,308	$5,035	$6,385	$7,867	$52,962

As Table 17-5 clearly indicates, both on a yearly basis and on a cumulative basis over the past 10 years, PG&E accrues much more net salvage dollars in rates than it actually spends. This is especially apparent when looking at the 10-year cumulative total. Over that 10-year period, PG&E has received in rates nearly 19 times more net salvage dollars than it has actually spent. Obviously, currently authorized net salvage rates are not reasonable and must be adjusted to more

[9] PG&E data response to ORA DR 266, Q. 2. Note that net salvage amounts associated with allocated plant (Common, General, etc.) have been excluded from both the "Received In Rates" and "Actually Spent" lines. Those amounts are small in comparison, and will not impact the conclusion that PG&E is receiving far more net salvage dollars than it is actually spending.

realistically reflect the actual dollars that are spent. ORA believes that the net salvage rates proposed by PG&E may still result in ratepayers paying too much for net salvage. However, PG&E's proposed net salvage adjustments move in the right direction and result in a decrease in depreciation expense. ORA recommends that they be adopted. The following table provides an account-by-account listing of the gas net salvage percentages being recommended by PG&E and ORA.

Table 17-6

GAS NET SALVAGE RECOMMENDATIONS BY FERC ACCOUNT

TEST YEAR 2003

Asset Class	FERC Account	Currently Authorized	PG&E Proposed	ORA Recommended (Same as PG&E Proposed)
Intangible Plant				
Franchises/Consents	302	0%	0%	0%
Software	303	0%	0%	0%
Local Storage Plant				
Structures & Improvements	361	10%	10%	10%
Gas Holders	362	-15%	-15%	-15%
Purification Equipment	363	--	--	--
Compressor Equipment	363.3	-20%	-20%	-20%
Measuring & Regulating Equipment	363.4	10%	10%	10%
Other Equipment	363.5	-5%	-5%	-5%
Gas Distribution				
Structures & Improvements	375	-20%	-20%	-20%
Mains	376	-55%	-45%	-45%
Compressor Station Equipment	377	-15%	-10%	-10%
Odorizing/Meas & Reg Station Equip	378	-30%	-55%	-55%
Services	380	-120%	-85%	-85%
Meters	381	5%	0%	0%
House Regulators	383	0%	0%	0%
Meas & Reg Station Equip - Industrial	385	-10%	-15%	-15%
Other Property on Customer Premises	386	0%	0%	0%
Other Equipment	387	-10%	0%	0%
Gas General				
Structures & Improvements	390	-10%	-10%	-10%
Office Furniture & Equipment	391	0%	0%	0%
Shop Equipment	394	9%	9%	9%
Laboratory Equipment	395	0%	0%	0%
Power Operated Equipment	396	10%	10%	10%
Miscellaneous Equipment	398	20%	20%	20%
Other Tangible Equipment	399	20%	20%	20%

CHAPTER 18

RATE BASE

I. INTRODUCTION

PG&E presents its proposal for rate base for electric and gas distribution in Exhibit PG&E-6, "Distribution Results of Operation", Chapter 13 "Rate Base". This chapter contains ORA's analyses and recommendations in response to that proposal. Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, Section III presents ORA's analysis of PG&E's request, support for ORA's estimates and adjustments, and provides ORA's conclusions.

II. SUMMARY/RECOMMENDATIONS

The four major components of Rate Base are Plant in Service, Depreciation Expense and Reserve, Working Capital, and Adjustments.

ORA recommends reductions to PG&E's estimates for rate base in four components: Plant in Service, Depreciation, Working Capital, and Deferred Taxes. Together, these reductions total $240,283,000, or 2.4% less than the company's total estimate.

Table 18-1 compares ORA's recommended and PG&E's proposed estimates for 2003 Electric Distribution Rate Base.

TABLE 18-1
RATE BASE – ELECTRIC DISTRIBUTION
Test Year 2003
($000)

	ORA Recommended	PG&E Proposed	Difference PG&E-ORA	Percent PG&E-ORA
Plant in Service	$14,506,291	$14,640,970	$134,679	0.9%
Depreciation	$5,917,840	$5,978,600	$60,761	1.0%
Working Capital	$28,493	$91,481	$62,988	68.9%
Adjustments				
TRA86 Adj	$198,144	$198,144	$0	0%
Customer Adv	$78,308	$78,308	$0	0%
Deferred Taxes	$1,038,450	$1,041,908	$3,458	0.3%
Total	$7,698,331	$7,831,780	$133,448	1.7%

ORA recommends reductions to PG&E's estimates for rate base in four components: Plant in Service, Depreciation, Working Capital, and Deferred Taxes. Together, these reductions total $133,448,000, or 1.7% less than the company's total estimate.

Table 18-2 compares ORA's recommended and PG&E's proposed estimates for 2003 Gas Distribution Rate Base.

TABLE 18-2
RATE BASE – GAS DISTRIBUTION
Test Year 2003
($000)

	ORA Recommended	PG&E Proposed	Difference PG&E-ORA	Percent PG&E-ORA
Plant in Service	$5,349,028	$5,414,309	$65,281	1.2%
Depreciation	$3,082,296	$3,071,740	-$10,556	-0.3%
Working Capital	$6,987	$44,091	$37,103	84.2%
Adjustments				
TRA86 Adj	$46,780	$46,780	$0	0%
Customer Adv	$15,510	$15,510	$0	0%
Deferred Taxes	$242,748	$248,855	$3,458	2.5%
Total	$2,062,241	$2,169,074	$106,833	4.9%

As Tables 18-1 and 18-2 show, ORA's recommendation for Rate Base is lower than PG&E's estimate. ORA's estimate reflects adjustments made by several different witnesses. Working Capital, TRA86 Adjustments, and Customer Advances are discussed in this chapter. Plant in Service is discussed in Chapter 14, Depreciation Expense and Reserve in Chapter 17, and Deferred Taxes in Chapter 13.

III. ANALYSIS/CONCLUSIONS

The four major components of Rate Base are Plant in Service, Depreciation Expense and Reserve, Working Capital, and Adjustments. The remainder of this chapter discusses the analyses and recommendation made by ORA with respect to the various components of Rate Base for electric and gas distribution, respectively.

A. Electric Distribution Rate Base

1. Plant in Service

ORA's estimate of total plant in service for electric distribution in test year 2003 is $14,506,291,000, compared to PG&E's estimate of $14,640,970,000. This is discussed in Chapter 14 of this report.

2. Depreciation Expense and Reserve

Net plant in service consists of plant in service minus the depreciation reserve. ORA estimates the depreciation reserve for the test year to be $5,917,840, compared with PG&E's estimate of $5,978,600,000. The development of ORA's estimate is covered in Chapter 17 of this report.

3. Working Capital

Working capital is material and cash the company must have on hand in order to conduct day-to-day business. Working capital is added to net plant in service in determining rate base. It consists of two components: Materials and

Supplies and Working Cash Capital. These components are discussed separately, below.

a. Materials and Supplies:

PG&E has undertaken a number of initiatives (described in Exhibit PG&E-4, Chapter 10) to streamline the acquisition of materials and supplies and reduce inventory on hand. As a result, the company has reduced its estimate for M&S for electric distribution by nearly 70% from that approved in the 1999 GRC. ORA reviewed the historical data and accepts PG&E's M&S estimate for electric distribution of $20,398,000 for the test year 2003.

b. Working Cash Capital:

Working cash capital is the amount of cash the company needs to have on hand to account for any lag between the time the company has to pay its bills and the time its customers pay their bills. This is determined by combining the results of the estimate of the total operational cash requirements with the estimate of the lag between the company's payment of bills and receipt of revenue. This lag is estimated using a lead/lag study.

PG&E estimates a total working cash capital requirement for $71,083,000 for electric distribution for the test year 2003. The corresponding ORA estimate is $8,095,000. Table 18-3 compares PG&E's and ORA's estimates for working cash capital.

TABLE 18-3

ELECTRIC DISTRIBUTION

WORKING CASH CAPITAL ($000)

	ORA Recommended	PG&E Proposed	Difference PG&E – ORA	Percent PG&E - ORA
Spcl Deposits	$182	$182	$0	0%
Other Recvbls	$25,247	$25,247	$0	0%
Prepayments	$3,191	$3,191	$0	0%
Deferred Debt	-$314	-$314	$0	0%
Less				
$ Not Supplied by Investors	$4,085	$4,085	$0	0%
Goods Delivered to Construction Sites	$2,243	$2,243	$0	0%
Accrued Vacation	$62,988	$0	-$68,649	-100%
Plus				
Lag Requirement	$49,104	$49,104	$0	0%
Total	$8,095	$71,083	-$68,649	-96.6%

ORA has reviewed PG&E's lead/lag study and accepts the resulting lag requirement as reasonable. ORA does, however, recommend an adjustment to the Accrued Vacation element of the Operational Cash Requirement.

PG&E asserts that there is no "accrual account" for vacation pay and sets this component at zero. ORA obtained data from PG&E allowing a computation for vacation accrual for 2003[1] using the previously approved methodology. The test year 2003 forecast for accrued vacation from PG&E's data is $62,988,000. ORA recommends that this amount, and not zero, be used to reduce the operational cash requirement The policy rationale for making this adjustment is discussed in Chapter 5 of ORA's "Results of Examination Report".

[1] PG&E response to ORA 0332-01

4. Other Adjustments

Adjustments include Tax Reform Act of 1986 adjustments (TRA86), Customer Advances, and Accumulated Deferred Taxes. Deferred Taxes are discussed in Chapter 13 of this report. TRA86 and customer advance adjustments are discussed here.

a. TRA86 Adjustments

TRA86 adjustments include Capitalized Interest, Contributions in Aid of Construction (CIAC) Deferral, and Deferred Vacation. TRA86 adjustments are added to net plant in service and working capital in determining rate base. ORA reviewed historical recorded data for each component from 1996 through 2001 and finds that the companies estimates of TRA86 adjustments totaling $198,144,000 are within reasonable expectations.

b. Customer Advances

Customer Advances represent refundable deposits new customers make to PG&E for extension of services. PG&E estimates customer advances attributable to electric Distribution to be $78,308,000 for the test year. This estimate is based on end-of-year recorded data for 2000 and discounts the substantially higher 2001 weighted average of $89,649,000 for this component as an aberration resulting from the bankruptcy filing. The company explains that it was impeded from promptly refunding deposits and that this resulted in a larger than expected balance in this account. ORA does not disagree with this explanation and accepts the company's estimate as reasonable.

5. Conclusion – Electric Distribution

Table 18-1 summarizes and compares ORA's and PG&E's rate base estimates for electric distribution. ORA recommends that its estimates be adopted. This results in an electric distribution rate base of $7,698,331,000 compared to the $7,831,780,000 proposed by PG&E

B. Gas Distribution Rate Base

Rate base for gas distribution consists of the same general components and calculated the same as that for electric distribution. These elements include: Plant in Service, Depreciation Expense and Reserve, Working Capital, and Adjustments PG&E estimates and ORA analysis for each component are discussed below.

1. Plant in Service

ORA's estimate of total plant in service for gas distribution in test year 2003 is $2,062,241, compared to PG&E's estimate of $5,414,309,000. This is discussed in Chapter 16 of this report.

2. Depreciation Expense and Reserve

Net plant in service consists of plant in service minus the depreciation reserve. ORA estimates this reserve for the test year to be $3,082,296, compared with PG&E's estimate of $3,071,740,000. This is discussed in Chapter 17 of this report.

3. Working Capital

As in electric distribution, working capital consists of two components: Materials and Supplies (M&S) and Working Cash.

a. Materials and Supplies

PG&E has undertaken a number of initiatives (described in Exhibit PG&E-4, Chapter 10) to streamline the acquisition of materials and supplies and reduce inventory on hand. As a result, the company has reduced its estimate for M&S for gas distribution by more than 70% from that approved in the 1999 GRC. ORA reviewed the historical data and accepts PG&E's M&S estimate for gas distribution of $2,714,000 for the test year 2003.

b. Working Cash Capital

The working cash capital requirement for gas distribution is calculated in the same manner as discussed above for electric distribution. A comparison of ORA and PG&E's forecasts for working cash capital is set forth in Table 18-4.

TABLE 18-4

GAS DISTRIBUTION

WORKING CASH CAPITAL ($000)

	ORA Recommended	PG&E Proposed	Difference PG&E – ORA	Percent PG&E – ORA
Spcl Deposits	$107	$107	$0	0%
Other Recvbls	$14,852	$14,852	$0	0%
Prepayments	$1,828	$1,828	$0	0%
Deferred Debt	-$186	-$186	$0	0%
Less				
$ Not Supplied by Investors	$2,340	$2,340	$0	0%
Goods Delivered to Construction Sites	$1,285	$1,285	$0	0%
Accrued Vacation	$37,104	$0	-$37,104	-100%
Plus				
Lag Requirement	$28,400	$28,400	$0	0%
Total	$4,273	$41,377	-$39,321	-95.0%

ORA has reviewed PG&E's lead/lag study and accepts the resulting lag requirement as reasonable. ORA does, however, recommend an adjustment to the Accrued Vacation element of the Operational Cash Requirement.

As in electric distribution, PG&E sets this gas Working Cash Capital component to zero on the assertion that there is no accrual account for vacation pay. Using traditional methodology previously adopted by this Commission,

however, this amount would be $37,104,000[2]. ORA recommends that this amount, and not zero, be used in calculating the working cash requirement. This results in a reduction in the overall working cash requirement for gas to $4,273,000, compared to PG&E's estimate of $41,377,000

4. Other Adjustments

Adjustments include Tax Reform Act of 1986 adjustments (TRA86), Customer Advances, and Accumulated Deferred Taxes. Deferred Taxes are discussed in Chapter 13 of this report. TRA86 and customer advance adjustments are discussed here.

a. TRA86 Adjustments

TRA86 adjustments include Capitalized Interest, Contributions in aid of Construction (CIAC) Deferral, and Deferred Vacation. TRA86 adjustments are added to net plant in service and working capital in determining rate base. ORA reviewed historical recorded data for each component from 1996 through 2001 and finds that the companies estimates of TRA86 adjustments totaling $46,780,000 is within historical expectation.

b. Customer Advances

Customer Advances represent refundable deposits new customers make to PG&E for extension of services.

PG&E estimates customer advances attributable to gas distribution to be $15,510,000 for the test year. This estimate is based on end-of-year recorded data for 2000 and discounts the substantially higher 2001 weighted average of $17,756,000 for this component as an aberration resulting from the bankruptcy filing. The company explains that it was impeded from promptly refunding

[2] PG&E response to ORA 0332-01

deposits and that this resulted in a larger than expected balance in this account. ORA does not disagree with this explanation and accepts the company's estimate as reasonable.

5. Conclusion – Gas Distribution

Table 18-2 summarizes and compares ORA's and PG&E's rate base estimates for gas distribution. ORA recommends that its estimates be adopted. This results in a gas distribution rate base of $2,062,241,000 compared to the $2,169,074,000 proposed by PG&E.

CHAPTER 19
POST TEST YEAR RATEMAKING

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) requests Post Test Year Ratemaking (PTR) for the years 2004 and 2005 for both its distribution and utility retained generation. The company sets forth its requests in Exhibit PG&E-8, "Attrition" and in Exhibit PG&E-10, "Retained Generation Results of Operations (Revised)," Chapter 16, "Attrition Proposal." This chapter only addresses the company's request for distribution-related attrition (PG&E-8). PG&E's request for attrition for its retained generation is addressed separately in ORA's "Report on the Results of Operations for Utility Retained Generation."

Section II of this chapter summarizes the differences between ORA's and PG&E's recommendations, Section III presents ORA's analysis of PG&E's request and support for ORA's forecasts and recommended adjustments and policy proposals, and Section IV provides ORA's conclusions.

II. SUMMARY AND RECOMMENDATIONS

For distribution attrition, both ORA and PG&E propose traditional attrition rate treatment for 2004 and 2005. A major policy difference is that ORA recommends third attrition year (2006) in order to stagger the processing of general rate cases for PG&E and the Southern California Edison Company.

A. <u>Post Test Year 2004 and 2005 Distribution Revenue Request</u>

PG&E is requesting increases of $64 million and $85 million for its electric distribution for years 2004 and 2005 respectively. The utility

is also requesting increases of $26 million and $32 million for its gas distribution operations for 2004 and 2005. ORA recommends as preliminary post test year increases of $58 million and $83 million for electric distribution for the years 2004 and 2005 and $23 million and $29 million for gas operations for the same period.

Table 19-1 summarizes the differences between PG&E's and ORA's recommendations for electric distribution.

Table 19-1

ELECTRIC DISTRIBUTION

POST TEST YEAR REVENUE INCREASE
(Dollars in millions)

	ORA	PG&E	PG&E>ORA	Percent
Post Test Year 2004				
Present Rate Revenues	$2,444	$2,722	$278	11.4%
Post Test Year Revenues	2,517	2,786	269	10.7%
Increase (decrease)	$58	$64	($6)	10.3%
% Increase (decrease)	2.4%	2.4%		
Post Test Year 2005				
Present Rate Revenues	$2,517	$2,786	$269	10.7%
Post Test Year Revenues	2,600	2,871	271	10.4%
Increase (decrease)	$83	$85	2	2.4%
% Increase (decrease)	3.0%	3.0%		

Table 19-2 depicts the differences between PG&E's request for increases revenues for its gas operations and ORA's recommendations for 2004 and 2005.

Table 19-2

GAS DISTRIBUTION

POST TEST YEAR REVENUE INCREASE
(Dollars in millions)

	ORA	PG&E	PG&E>ORA	Percent
Post Test Year 2004				
Present Rate Revenues	$908	$1,006	$98	10.8%
Post Test Year Revenues	931	1,032	101	10.8%
Increase (decrease)	$23	$26	$3	13.0%
% Increase (decrease)	2.5%	2.6%		
Post Test Year 2005				
Present Rate Revenues	$931	$1,032	101	10.8%
Post Test Year Revenues	960	1,064	104	10.8%
Increase (decrease)	$29	$32	3	10.3%
% Increase (decrease)	3.1%	3.1%		

ORA's differences with PG&E's PTR request is the result of a variety of factors, which originate primarily from:

1. The difference in the respective proposed test year 2003 estimates for all expenses, and
2. ORA's lower estimates of 2003 capital additions and related functions.

PG&E proposes using a traditional ratemaking attrition mechanism for its Distribution operations. This includes escalating 2003 expenses and applying a seven year average to estimate the post test year plant additions. ORA finds that the use of a traditional attrition mechanism is acceptable for purposes of this proceeding. This matter is discussed in greater detail in Section III (A) of this chapter.

B. Post Test Year Ratemaking in 2006

PG&E proposes that 2006 be approved as its next test year following its second attrition year 2005. ORA recommends that PTR be extended to include the year 2006, i.e. 2006 should be identified as a third attrition year following test year 2003 and that 2007 should consequently be PG&E's next test year. Section III (B) of this chapter provides ORA's explanations and reasoning for this recommendation.

III. DISCUSSION/ANALYSIS

A. Post Test Year 2004 and 2005 Distribution Revenue Request

1. Expenses

Attrition projections are initially based on test year results. Hence, differences in this proceeding arise partially due to estimated results of the respective witnesses. For example, PG&E is requesting more for test year 2003 for A&G and O&M expenses than ORA is recommending. These differences in A&G and O&M expenses in the test year establish the foundation for the attrition year projections. The difference in test year cost estimates accounts for a major portion of the differences in the attrition projections of ORA and PG&E for attrition years 2004 and 2005.

To arrive at attrition year expense projections for 2004 and 2005, PG&E escalated 2003 data by factors obtained from forecasts prepared by Global Insight (formerly DRI) in the first quarter 2002. According to the Rate Case Plan these numbers will be updated on Day 280 to provide the most recent data upon which the Commission will base its 2003 test year and 2004 and 2005 attrition years decision. Also, PG&E should provide an update of all estimates used as a basis for its future rate requests at the

time PG&E files for each attrition year. Overall ORA finds PG&E's approach to projecting attrition distribution expenses to be reasonable.

2. Capital Additions

With respect to PG&E's request for funding for attrition year distribution capital additions, ORA does not dispute the traditional Attrition Rate Adjustment (ARA) methodology that PG&E applied to arrive at its capital addition estimates. The approach projects attrition year capital spending by averaging seven historic years of data including estimated year 2002 and test year 2003.

B. Post Test Year Ratemaking in 2006

ORA recommends that 2006 serve as a third attrition year for PG&E rather than be designated as test year for PG&E's next GRC. ORA recommends that attrition for 2006 be developed using the same methodology as applied in 2004 and 2005. ORA recognizes that PG&E may require funding for specific capital projects or face expenses which could possibly exceed the level provided under the traditional ARA mechanism. To address this issue, ORA proposes that the company be permitted to file an application and request expedited rate relief in lieu of the traditional attrition. This would allow the utility the option to file an expedited application to seek rate relief to cover those anticipated expenses and capital additions, which the company believes justifiably warrant a request for funding above that afforded by the ARA.

In addressing issues set forth in PG&E's current application, ORA finds its limited resources stretched due to the number of general rate case filings. ORA notes in particular Southern California Edison Company's (SCE) current 2003 test year GRC (A.02-05-004) filing coincides with PG&E current 2003 test year filing. The Edison case alone requires the

use of 19 witnesses of which nine were also ultimately assigned to PG&E's 2003 GRC. Many of the staff witnesses are involved in various phases of these cases from discovery to testifying to working with the assigned attorney on opening briefs or responding to interrogatories or preparing or delivering testimony. Hence, the resources of ORA have been very strained. Commission Resolution No. A-4693 (July 6, 1977) recognized that in adopting the Rate Case Plan "…that regulatory lag is a substantial problem confronting the administrative process. Its causes are many and include not only the actions of the utilities under our jurisdiction and their participants in the process, but also inadequate Commission staffing and sometimes burdensome procedures." Hence, ORA reasonably contends that the current problem of regulatory lag (both the 1999 and 2003 test year PG&E GRC's are coincidently slated to have had decisions rendered two months following their test years) will be mitigated by placing SCE and PG&E off-cycle by adopting 2006 as a third attrition year for PG&E and moving PG&E's next test year to 2007, while SCE would retain a 2006 test year. Given the nearly concurrent processing of the Edison and PG&E test year 2003 general rate cases, the most logical approach is to extend the test year of PG&E to 2007 while retaining a 2006 test year for SCE.

ORA additionally notes that if PG&E were to file a 2006 test year GRC, the utility would have to file in August of 2004. This would be approximately six months from the anticipated February 5, 2004, date of the Commission's decision for PG&E's current 2003 test year GRC filing. ("Assigned Commissioner's Ruling Establishing Scope, Schedule, and Procedures for Proceeding," p. 10.)

Another benefit of extending the rate case cycle through a third attrition year is that it will provide the Commission with more information

on which to base its next decision. Designating 2006 as the next test year would possibly mean the use of 2003 as a base year. This would afford the Commission more limited, new information for the record with which to establish a factual basis for PG&E's 2006 GRC decision. Approving 2007 as the next test year will allow Edison and PG&E to move off-cycle and will afford the Commission an additional year of recorded data. This may prove to be vital given PG&E's federal bankruptcy proceeding and the utility's attempt to comport with ABx1-6 by ramping up its capital outlays.

ORA recognizes that the purpose of the attrition mechanism is to allow utilities to have a reasonable opportunity to earn their authorized rate of return between test years. Consequently, ORA proposes to allow PG&E the option to file an application of limited scope in 2006 for rate relief for expenses and capital additions that it encounters following test attrition years 2004 and 2005 beyond that provided by the tradition attrition mechanism.[1] This would include specific charges, which are not reflected through inflation or a seven-year average of recorded capital additions. ORA recommends this approach because it recognizes that 2006 would have been a test year for a full general rate case for which ORA is seeking an alternative to mitigate high workload. ORA believes this approach is reasonable given current circumstances.

IV. CONCLUSION

ORA has analyzed and evaluated PG&E-8, "Attrition" and agrees with the attrition mechanism proposed by PG&E for electric and gas distribution. ORA's

[1] The traditional attrition mechanism would remain the default method to develop the 2006 attrition rate increase. The submittal of an application is an optional filing to be made at PG&E's discretion.

estimated expense and capital expenditure levels for the attrition years are lower than PG&E's primarily due to ORA's lower test year estimates. ORA also proposes an additional attrition year for 2006 primarily as a means of staggering the processing of the next GRCs for PG&E and SCE.