STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

April 6, 2004

TO: PARTIES OF RECORD IN APPLICATION 02-11-017 ET AL.

RE: NOTICE OF AVAILABILITY OF PROPOSED DECISIONS ON:
(1) INTERIM OPINION ON STORM AND RELIABILITY ISSUES (AGENDA ID #3431)
(2) OPINION: PHASE 1 ISSUES (AGENDA ID #3432)

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decisions. These proposed decisions are issued by Administrative Law Judge (ALJ) Julie M. Halligan on April 6, 2004. An Internet link to these documents were sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of these documents can be viewed and downloaded at the Commission's Website (www.cpuc.ca.gov).

Any recipient of this Notice of Availability who is not receiving service by electronic mail in this proceeding or who is unable to access the link to the Commission's web site given above may request a paper copy of the above documents from the Commission's Central Files Office, at (415) 703-2045; e-mail cen@cpuc.ca.gov.

These are the proposed decisions of ALJ Halligan, previously designated as the principal hearing officer in this proceeding. They will not appear on the Commission's agenda for at least 30 days after the date they are mailed. This proceeding was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting to consider these proposed decisions may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the Ratesetting Deliberative Meeting 10 days before hand, and will advise the parties of this fact, and of the related ex parte communications prohibition period.

When the Commission acts on the proposed decisions, it may adopt all or part of them as written, amend or modify them, or set them aside and prepare its own decisions. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file separate sets of comments on each of the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages for each proposed decision.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Halligan at jmh@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ Halligan, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission's Web page, www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:jva

Attachment

Decision **PROPOSED DECISION OF ALJ HALLIGAN (Mailed 04/06/2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, To Increase Revenue Requirements for Electric and Gas Service and to Increase Rates and Charges for Gas Service Effective on January 1, 2003. (U 39 M)	Application 02-11-017 (Filed November 8, 2002)
Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company.	Investigation 03-01-012 (Filed January 16, 2003)
Application of Pacific Gas and Electric Company Pursuant to Resolution E-3770 for Reimbursement of Costs Associated with Delay in Implementation of PG&E's New Customer Information System Caused by the 2002 20/20 Customer Rebate Program. (U 39 E)	Application 02-09-005 (Filed September 6, 2002)

(See Attachment E for List of Appearances)

OPINION: PHASE 1 ISSUES

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OPINION: PHASE I ISSUES

1. Summary

This decision resolves issues litigated in the revenue requirement phase (Phase 1) of Pacific Gas and Electric Company's (PG&E) test year (TY) 2003 General Rate Case (GRC). In this decision, we consider two comprehensive settlements filed by the majority of parties in this proceeding. Pursuant to Rule 51 *et seq*. of the Commission's Rules of Practice and Procedure, we consider a Settlement Agreement proposed by PG&E, the Office of Ratepayer Advocates (ORA), the Utility Reform Network (TURN), Aglet Consumer Alliance (Aglet), Modesto Irrigation District (MID), the Natural Resources Defense Council (NRDC), and the Agricultural Energy Consumers Association (AECA), (collectively, "the Settling Parties"), that resolves all but one of the issues raised by the Settling Parties regarding PG&E's forecast TY 2003 electric and gas revenue requirements and 2004, 2005, and 2006 attrition requests (the Distribution Settlement). We also consider a separate Settlement Agreement proposed by PG&E, ORA, TURN, Aglet, and the City and County of San Francisco (CCSF) regarding PG&E's forecast TY 2003 generation revenue requirements and related attrition, (the Generation Settlement).

Taken together, the Distribution Settlement and the Generation Settlement (also referred to jointly as the Settlements) provide for a TY 2003 revenue requirement of approximately $2.493 billion for electric distribution, $927 million for gas distribution, and $912 million for generation. Excluding revenues related to procurement, this represents an increase of approximately $236 million, or 10.44% in electric distribution revenues, $52 million, or 5.90% in gas distribution revenues, and $38 million, or 4.35% in generation revenues. A portion of the increase in GRC-related revenues is collected as other operating revenues, rather than from sales of electricity and gas. Therefore, the increase in revenues from sales to customers resulting from the Settlements is 8.46% electric distribution, 4.60% gas distribution and 3.90% generation.

With one modification, we find that the Settlements are reasonable in light of the whole record, consistent with the law, and in the public interest. While the Settlements are to a certain extent "black box" settlements that do not represent the increased level of precision we sought when we approved PG&E's TY 1999 revenue requirement request, we are satisfied that they are in the public interest.

The 2003 base revenues authorized today are effective as of January 1, 2003, consistent with our decision in Decision (D.) 02-12-073. However, as a result of our recent approval in D.02-04-062 of a Rate Design Settlement lowering PG&E's rates by $799 million, the increase in PG&E's revenue requirements for electric distribution and generation authorized today has already been reflected, and to a large degree, offset, as part of the revenue requirement reductions approved in D.02-04-062.

PG&E's bundled gas distribution base revenues are changed by this decision as shown in the following table.[1]

Table 1

Class	**Changes in Annual Revenues ($000's)**	**Revenue Change Percent**
Core Customers		
Residential	$30,147	1.8
Small Commercial	9,355	1.9
Large Commercial	126	0.9
	0	0
Wholesale		
Non-Core Customers		
Industrial Distribution	1,349	3.4
Industrial Transmission	0	0
Electric Generation	54	0.2
Cogeneration	30	0.2
Shareholder Absorption[2]	115	4.7
Total Change	$41,176[3]	1.8%

[1] Revenue changes are allocated to customer classes using the marginal cost revenues adopted in PG&E's 2000 Biannual Cost Allocation Proceeding (BCAP) (D.01-11-001).

[2] Amount represents 50% of the scaled distribution marginal cost revenue allocated to industrial transmission customers. D.98-06-073 (p. 20) ordered PG&E to reduce the distribution revenue requirement by 50% of the amount allocable to this customer class through the end of the Gas Accord period.

[3] This is the total increase in CPUC revenue from sales; an additional amount of $10,442 from Other Operating Revenue (OOR) must be added to this amount to get the total rate case CPUC revenue increase of $51,618.

As a result of this decision, a residential gas customer using an average of 50-therms per month on a year-round basis would see average monthly bill increases of 67 cents.

As part of the Distribution Settlement considered and adopted in this decision, the next test year for PG&E will be 2007. We therefore direct PG&E to tender its Notice of Intent for the TY 2007 GRC consistent with the Rate Case Plan.[4]

In addition to the issues addressed in the Settlements, we consider Applicant's request for approval of a $128.6 million (total Company) contribution to the Company's Retirement Plan trust. Today's decision denies PG&E's request, finding that PG&E did not provide clear and convincing evidence that a contribution is needed at this time.

We also resolve disputed issues related to the Diablo Canyon Independent Safety Committee (DCISC). Today's decision approves a Stipulation filed by PG&E, ORA, the DCISC, TURN, and the Mothers for Peace, which provides that the DCISC shall continue with its current responsibilities and funding through "the term of this GRC." Today's decision also grants, in part, the Mothers for Peace Petition to modify D.88-12-083.

Finally, in this decision, we examine issues related to PG&E's executive compensation. We review and comment on certain executive bonuses designed to promote the retention of certain corporate officers during the difficult period of the energy crisis and the financial insolvency and bankruptcy of PG&E and PG&E Corp.'s non-utility affiliates. We find that the Senior Executive Retention

Bonus Program has been, or will be, funded by shareholders, not ratepayers, and we adopt additional accounting and reporting measures to ensure that this remains the case.

This decision resolves all issues in Phase 1 of PG&E's TY 2003 GRC. Phase 2 of this proceeding will address marginal cost, revenue allocation and rate design. This proceeding remains open.

2. Procedural History

PG&E's last general rate increase was authorized in D.00-02-046. D.00-02-046 ordered PG&E to file a TY 2002 GRC in accordance with the Rate Case Plan. The Rate Case Plan schedule called for PG&E to file a Notice of Intent (NOI) for the TY 2002 GRC in summer 2000, and its GRC application in the fall of 2000. D.00-07-050 subsequently modified D.00-02-046 to delay the scheduled filing date of the TY 2002 GRC by nine months and directed PG&E to tender its NOI on May 1, 2001.

In response to a request from PG&E, in D.01-03-052 dated March 27, 2001, the Commission extended the date for tendering the NOI on a day-to-day basis while it considered possible further modifications to the plan for processing PG&E's TY 2002 GRC. The Commission observed that there was a need to ensure that its resources and those of PG&E and the other parties were not diverted from more critical efforts to respond to the California energy crisis. In D.01-10-059, dated October 25, 2001, the Commission changed the test year for PG&E's next GRC from 2002 to 2003 and directed PG&E to tender its NOI by November 14, 2001. PG&E failed to do so, leading to D.02-04-018, in which the

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[4] The Rate Case Plan was adopted in D.89-01-040.

Commission ordered PG&E to tender its NOI for the TY 2003 GRC no later than April 15, 2002. Applicant tendered its NOI in accordance with D.02-04-018.

On June 7, 2002, the Commission issued D.02-06-003, modifying the schedule for processing PG&E's TY 2003 GRC and adopting a goal of having new rates in place by June 1, 2003. Consistent with its determination in D.98-12-078, issued in connection with PG&E's TY 1999 GRC, the Commission then issued D.02-12-073, dated December 23, 2002, directing that any revisions to PG&E's revenue requirements resulting from the TY 2003 GRC may be made effective January 1, 2003.

PG&E filed its formal application for its TY 2003 GRC, Application (A.) 02-11-017, on November 8, 2002. On January 16, 2003, the Commission instituted Investigation (I.) 03-01-012 into the rates, charges and practices of PG&E and consolidated the investigation with the GRC application for purposes of considering recommendations beyond the scope of PG&E's application. Prehearing conferences were held on January 28, 2003, and May 21, 2003 to address procedural matters and schedule hearing dates. On February 13, 2003, Assigned Commissioner Peevey issued an "Assigned Commissioner's Ruling Establishing Scope, Schedule, and Procedures for Proceeding" (ACR) establishing the procedural schedule and calling for hearings to begin on May 28, 2003.

The ACR directed PG&E to file supplemental testimony to address several issues, including, but not limited to: (1) storm response and reliability performance issues;[5] (2) workforce diversity; and (3) compliance with Pub. Util.

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[5] The Commission addressed the storm and reliability issues as a separate phase of this proceeding. With the exception of the agreement regarding PG&E's Safety Net Program, addressed in Section 7.23 below, all storm and reliability issues are dealt with in the storm and reliability phase.

Code § 739.10. PG&E filed and served supplemental testimony on these issues on March 17, 2003. In addition, on April 7, 2003, pursuant to the ACR, PG&E filed testimony regarding integrated resource planning, in which PG&E was advised to "assume that it will remain a vertically integrated utility responsible for procuring and providing resources to its customers and should identify the costs of staffing and supporting this responsibility."

PG&E initially requested a revenue requirement of $3.042 billion for retained generation, including forecast costs for fuel and purchased power. Pursuant to D.02-10-062, which directed that fuel and purchased power costs would be reviewed as part of each utility's ERRA proceeding, PG&E served revised testimony on February 20, 2003, removing fuel costs ($286 million) and purchased power costs ($1.735 billion) from its forecast 2003 retained generation request requirement.

On April 11, 2003, ORA served testimony in response to PG&E's November 8, 2002 Application. TURN, Aglet and other intervenors served their testimony on May 2, 2003. Rebuttal testimony was served on May 22, 2003.

Evidentiary hearings began on May 28, 2003, and continued through July 29.[6] 24 parties filed appearances in this proceeding. Of those, eight participated in the evidentiary hearings, filed briefs, or both. Testimony was presented by PG&E, the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), Aglet Consumer Alliance (Aglet), the California Coalition of Utility Employees (CUE), Modesto Irrigation District (MID), The

[6] The first phase of the hearings related to PG&E's response to the December 2002 storm and reliability issue are not addressed in this decision.

Greenlining Institute/Latino Issues Forum (Greenlining), the San Luis Obispo Mothers For Peace (Mothers for Peace), the City and County of San Francisco (CCSF), the Natural Resources Defense Council (NRDC), and William Adams (Adams).

Public Participation Hearings were held in San Mateo, San Francisco, Santa Rosa, Fresno, and San Luis Obispo during the month of August, 2003. Altogether, the Commission held two prehearing conferences, 36 days of evidentiary hearings, and five public participation hearings in this proceeding. The Assigned Commissioner was in attendance at the first prehearing conference and at two of the public participation hearings.

On July 31, 2003, PG&E, ORA, TURN, Aglet, and CCSF filed a joint motion for approval of a settlement of the contested issues raised in connection with PG&E's forecast 2003 electric generation revenue requirement and electric generation attrition request. As required by Rule 51 of the Commission's Rules of Practice and Procedure (Rules), PG&E convened a noticed settlement conference on July 14, 2003.[7] Pursuant to Rule 51.4, comments on the Generation Settlement were to be filed within 30 days from the date of mailing of the settlement. No party filed comments on the Generation Settlement.

On August 18, 2003, TURN and ORA requested and were granted a two-week extension of the briefing schedule. On September 2, 2003, PG&E, TURN, ORA and Aglet requested an additional extension of the briefing schedule to allow parties to discuss possible settlement of the remaining issues.

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[7] Representatives from NRDC and the Mothers For Peace attended the settlement conference but did not join in the Generation Settlement.

In compliance with Rule 51, PG&E convened a second noticed settlement conference on September 9, 2003.

On September 15, 2003, PG&E, ORA, TURN, Aglet, MID, NRDC, and AECA, collectively, the "Settling Parties," filed a Motion for Approval of a Settlement Agreement (hereinafter referred to as the Distribution Settlement) and a Request to Shorten Time to file comments on the Distribution Settlement. The Settling Parties also requested that the Commission extend or waive the deadline in Rule 51.2.[8] No objections were raised to the motion to extend or waive Rule 51.2. Good cause having been shown, we will waive Rule 51.2.

On September 16, 2003, the Administrative Law Judge (ALJ) directed interested parties to file responses to the Request to Shorten Time by September 19, 2003. No party filed a response. The ALJ then directed that comments on the Motion for Approval of Settlement Agreement were to be filed by October 1, 2003 with reply comments to be filed by October 7, 2003. On October 1, 2003, the California Department of Water Resources (DWR) submitted a memorandum commenting on the Distribution Settlement. The Settling Parties filed a joint response to DWR's memorandum on October 7, 2003.[9] No other party commented on the Distribution Settlement.

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[8] Rule 51.2 provides that parties may propose a settlement for adoption by the Commission within 30 days after the last day of hearing. The last day of hearing in Phase 1 was July 29, 2003, and the Distribution Settlement was filed on September 15, 2003.

[9] NRDC did not join in the section of the Distribution Settlement, which is the subject of DWR's memorandum and therefore did not join in the Reply.

Opening Briefs were filed by PG&E, ORA, Aglet, Greenlining, and the Mothers for Peace on September 17, 2003. Reply Briefs were filed by PG&E, ORA, Greenlining, CUE and Mothers for Peace on October 8, 2003. Phase 1 was submitted on October 8, 2003, upon receipt of the Reply Briefs.

At the Commission's January 8, 2004 meeting, two Commissioners commented on applicant's recent award of over $80 million in retention bonuses to its topmost executives. On January 15, 2004, Latino Issues Forum wrote the Commission urging an investigation into PG&E's "excessive" retention bonuses. On January 15, 2004, Greenlining filed a motion asking the Commission to take official notice of a recent newspaper article regarding PG&E's executive bonuses and to reopen the record. On January 30, 2004, Greenlining filed a notice of withdrawal of the motion.

On February 3, 2004, the assigned ALJs issued a Ruling setting aside submission and taking further evidence regarding executive compensation and bonuses. Among other things, the Ruling asked applicant to file a report by February 10, 2004 addressing 11 issues. On February 6, 2004, applicant filed a motion seeking to revise the Ruling to narrow the scope of the inquiry to two issues, but committed to comply with the original ruling absent a grant its motion. No Ruling was issued on the February 6, 2004 motion.

As a result, in compliance with the February 3, 2004 Ruling, applicant filed a report on February 10, 2004. On February 13, 2004, applicant filed an errata to the February 10 report. On February 18, 2004, Greenlining filed comments on the February 10, 2004 report. On February 20, 2004, applicant filed reply comments.

By Ruling dated February 23, 2004, the ALJs asked applicant to provide limited additional information. On February 27, 2004, applicant filed a supplemental report, and the matter was resubmitted for Commission decision.

This GRC is being processed in two phases; Phase 1, which considers revenue requirement issues and Phase 2, which considers rate design and revenue allocation issues. Today's decision resolves the issues litigated in Phase 1.

3. PG&E's Request

The energy industry has undergone significant changes since PG&E's last GRC. At that time, California was in the process of restructuring the electric industry consistent with the requirements of Assembly Bill (AB) 1890 (Stats.1996, Ch. 854) and PG&E was the only large electric utility in the state that had not shifted from cost of service ratemaking to Performance-Based Ratemaking. When we issued D.00-02-046, we expressed concern regarding the large difference between the revenue requirement requested by PG&E and the revenue requirement recommended by ORA and other parties as well as the "history of divergence between authorized revenues and actual expenditures in mission critical areas." We observed that, "after two years of proceedings…we are still faced with making significant decisions about PG&E's revenue requirements, accounting and costing practices and service levels based on judgments that are informed by less than clear or precise information." (D.00-02-046 *mimeo.*, 28.) We adopted certain measures designed to improve the accuracy of PG&E's next GRC filing,[10] in the hope that, these measures, combined with the concerted effort of all the parties, would result in a much more accurate and much less

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[10] In particular, in order to get a better handle on PG&E's actual cost of service, we adopted a one-way balancing account for vegetation management activities and an audit of 1999 capital spending.

controversial TY 2003 GRC filing. As a result of the energy crisis in 2001 and the subsequent filing by PG&E for Chapter 11 bankruptcy protection on April 6, 2001, not only do we continue to face many of the same issues we had hoped to eliminate, but additional complications have emerged.

On September 20, 2001, PG&E and PG&E Corporation, as co-proponents, filed a Plan of Reorganization (POR) in PG&E's bankruptcy case. The POR provided for the disaggregation of PG&E's business into four companies, removing PG&E's hydroelectric generation facilities, natural gas transmission assets, and nuclear facilities from Commission regulation.

In its initial application, PG&E proposed overall forecast test year 2003 electric and gas distribution revenue requirements of $2,716 million and $1,000 million, respectively, which would result in increases of $447 million, or 19.7%, in electric distribution revenues and $105 million, or 11.7%, in gas distribution revenues over then current authorized revenue requirements. (Exhibit 1, p. 1-1.)

PG&E also sought attrition year revenue requirement increases in 2004 and 2005. PG&E proposed that attrition year increases would be updated just prior to each attrition year, based upon current escalation and other information. PG&E estimated its attrition year increases at $64 million in 2004 and $85 million in 2005 for its electric distribution operations and $26 million for 2004 and $32 million for 2005 for its gas distribution operations. (Exhibit 8, p. 2-8 and 2-9.)

In its February 20, 2003 update pursuant to the ACR, PG&E requested a TY 2003 generation revenue requirement of $1,022 million, representing a $149 million increase over the authorized 2002 revenue requirement (Exhibit 10, pp. A-1 to A-2) and forecast generation attrition changes for 2004 and 2005 of a

$33.7 million increase and a $39.3 million decrease, respectively. (Exhibit 10, p. 16-1.)

Applicant claims that its request is reasonable in light of rising costs over the four-year period since PG&E's last GRC including: cost increases caused by: continuing wage and price inflation; the costs of new programs; the cumulative increase in capital investment as customers and activity continue to grow; and the need to replace aging infrastructure with new facilities. In addition to these general cost increases, applicant states that there are at least four special cost drivers reflected in its request: (1) the updating of electric and gas distribution rates to ensure that depreciation costs are allocated fairly to ratepayers over time; (2) resuming contributions to PG&E's Retirement Plan trust; (3) the inclusion of certain A&G elements that were not included in the costs adopted in the 1999 GRC (*e.g.*, a portion of Performance Incentive Plan payments and certain support costs billed by PG&E Corporation); and (4) a substantial "ramp-up" in generation expenditures required by the recent shift in regulatory policy direction away from the short-term maintenance and back toward long-term investment.

When PG&E filed its application, it indicated that it was not seeking a change in total electric rates related to the increased electric revenues it was requesting, due to the electric rate freeze that was in effect at that time. PG&E acknowledged that future rates may be affected if the Commission approves its request. PG&E's requested increase in gas distribution revenues was expected to increase a typical residential customer's total gas bill by 4.1 %, or $1.56 per month.

PG&E also stated that the Chapter 11 protection for which PG&E filed in April 2001 allows PG&E to operate its distribution business in the "ordinary course," *i.e.*, continuing to provide safe and reliable electric and gas distribution service to its customers. PG&E states that its GRC request covers only the costs of continuing to provide distribution services to its customers and does not reflect its POR.

4. The Distribution Settlement

The Distribution Settlement is 24 pages long and has four separate appendices; it is reproduced as Attachment A to this decision. As required by Rule 51.1(c), Attachment B to the Distribution Settlement is a comparison exhibit (the Agreement Comparison Exhibit) indicating the effect of the Distribution Settlement in relation to PG&E's showing and to issues ORA contested.

The Distribution Settlement would resolve all issues raised by the Settling Parties regarding PG&E's forecast TY 2003 electric and gas distribution and generation revenue requirements, and 2004, 2005, and 2006 electric and gas distribution and generation revenue requirements, with one exception. The Distribution Settlement does not address applicant's request that the Commission approve a $128.6 million (total Company) contribution to PG&E's Retirement Plan trust.

The Settling Parties request that the Commission: (1) resolve the single remaining disputed issue among the Settling Parties related to PG&E's request that the Commission adopt PG&E's forecast contribution to its pension fund; (2) adjust the revenue requirements set forth in the Distribution Settlement according to the Commission's resolution of the disputed issue; (3) resolve any issues raised by non-settling parties; (4) extend or waive the deadline in Rule 51.2 of the Commission's Rules of Practice and Procedure requiring a proposed settlement to be filed within 30 days of the last day of hearing; and (5) issue a final decision approving the Distribution Settlement. Key provisions of the Distribution Settlement include:

- Section 1 of the Distribution Settlement provides for TY 2003 revenue requirements of $2,493 million for electric distribution, and $927 million for gas distribution ($2003), representing a 10.44% increase in electric distribution revenues and a 5.90% increase in gas distribution revenues.

- Section 2 of the Distribution Settlement provides for a TY 2003 generation revenue requirement of $912 million, a $38 million or 4.35% increase from present revenues. This amount reflects reductions from the Generation Settlement associated with A&G expense, common plant, and tax issues, as discussed below.
- Section 3.1 of the Distribution Settlement provides for A&G expenses of $585 million ($2000 total utility). This amount for A&G expense does not include a pension contribution. The agreement does include an amount for net wage-related pension expense of $1.7 million. In Section 3.1.3 the Settling Parties agree on capitalization rates for those A&G items that are capitalized.
- Section 3.1.4 of the Distribution Settlement provides that the A&G expenses allocated to the Unbundled Cost Categories (UCCs) adopted in this GRC should be used in determining the A&G expenses in related proceedings in 2003 and future years until the 2007 test year, if the outcome of those proceedings would otherwise require specific calculation of A&G expenses. The specific UCCs and related proceedings are: Gas Transmission (Gas Accord II and Gas Accord III), Humboldt (Nuclear Decommissioning Cost Triennial Proceeding), Gas Public Purpose Programs (PPP) and Electric PPP.
- Section 3.2.1 provides that PG&E’s distribution Operations and Maintenance (O&M) expenses will be $391.5 million electric and $118.5 million gas (expressed in $2000 FERC dollars). Section 3.2.2 provides that Vegetation Management expense (included in the above O&M total) will be $124.7 million. The one-way balancing account for Vegetation Management and the Vegetation Management Quality Assurance Program adopted in D.00-02-046 would continue, as would the tree removal program. Shareholders would no longer share in the cost of the Vegetation Management Quality Assurance Program.

- The Settling Parties agree that PG&E's distribution Customer Accounts expenses will be $199.9 million electric and $154.7 million gas. Customer Accounts expenses include several changes in PG&E's administration of the line extension process to ensure that expenses related to new customer connection applicants are charged to those applicants as opposed to the general body of ratepayers.
- The Settling Parties agree that PG&E's distribution Customer Services expenses will be $1.363 million electric and $3.483 gas ($2000). This reflects zero expense in the Account 912 revenue requirement for customer retention and economic development.
- The Settling Parties agree to the depreciation parameters resulting from ORA's position on electric, gas and common plant depreciation.
- The Settling Parties agree to use recorded 2002 plant as the starting point for calculating 2003 rate base. The Settling Parties agree to allocate residual common plant and depreciation reserve using the allocation method presented in PG&E's rebuttal testimony.
- The Settling Parties agree that net weighted capital additions for 2003 will be $292 million for the electric distribution UCCs and $89.2 million for the gas distribution UCCs ($2003).
- Section 4.8 of the Distribution Settlement provides for an annual $7 million credit against the revenue requirement to resolve TURN's recommended CIS capital disallowance. PG&E will retain the capital in question in rate base and continue depreciation using the applicable depreciation schedule for CIS.

- Section 5 of the Distribution Settlement defers PG&E's next GRC until TY 2007 and provides for an additional attrition adjustment for 2006. Section 5.2 and 5.3 provide that attrition relief for 2004, 2005, and 2006 will be authorized in this GRC and implemented by advice letter. The annual attrition adjustments in 2004 and 2005 will be equal to the previous year authorized revenue requirement times the forecast change in Consumer Price Index (CPI) – All Urban Consumers. The attrition adjustment for 2006 will be equal to the previous year authorized revenue requirement times the forecast change in CPI – All Urban Consumers, plus one percent. Notwithstanding the forecast change in CPI, Section 5.3 provides for minimum and maximum attrition adjustments.

5. The Generation Settlement

On July 31, 2003, PG&E, ORA, TURN, Aglet and CCSF filed a Generation Settlement resolving disputed issues regarding the forecast test year 2003 generation revenue requirements and 2004, 2005, and if applicable, 2006 attrition adjustments.[11] The Generation Settlement is included as Attachment B to this decision. The Parties to the Generation Settlement maintain that the Generation Settlement resolves all issues specifically related to generation raised in PG&E's TY 2003 GRC (with the exception of the general A&G and tax issues). The Parties believe that the Generation Settlement represents a reasonable compromise of strongly held positions, permitting PG&E to recover reasonable costs of necessary capital investment in, and operations and maintenance of, its generation assets at a cost lower than the generation

[11] CCSF joined in the Generation Settlement only to the extent it addresses the selective catalytic reductions project at the Hunters Point Power Plant. CCSF takes no position on the other issues resolved by the Generation Settlement.

revenue requirement initially requested by PG&E. Key provisions of the Generation Settlement include:

- A TY 2003 electric generation revenue requirement of $955 million, subject to adjustment for generic A&G and tax issues.
- Generation regulatory assets will be amortized over the remainder of the 10-year schedule adopted in D.02-04-016. For purposes of this agreement, the generation regulatory assets include Western Area Power Administration (WAPA), Helms, and Loss on Sale of Power Plants.
- Major components of Diablo Canyon will be amortized over 19 years beginning in 2003.
- Attrition adjustments in 2004, 2005, and, and if applicable, 2006, equal to the previous year authorized revenue requirement times the CPI, plus specific adjustments for the costs of increased security requirements and refueling outages at Diablo Canyon.
- PG&E's proposed low-pressure turbine rotor replacement projects will be reviewed as part of the TY 2007 GRC and PG&E will file a separate application for steam generator replacement project.
- Adjusts PG&E's 2004 and 2005 capital forecast by $500,000 and $15 million, respectively, to eliminate funding for the installation of Selective Catalytic Reduction pollution control equipment at Hunters Point.

6. Commission Review of the Settlements

The primary purpose of this proceeding is to determine the base revenue requirements necessary for PG&E's electric and gas distribution and electric generation operations. As noted above, the Settlements would address our core question in this proceeding by resolving virtually all of the disputed issues in the revenue requirement phase of PG&E TY 2003 GRC. The Settling Parties maintain that the Distribution Settlement and the Generation Settlement are reasonable in light of the whole record, consistent with the law, and in the public interest. They point to the fact that the revenue requirements contemplated by the Settlements are within the range of dispute as the primary indication of the reasonableness of the Settlements. The proposed Settlements, including the addendum, set forth the Settling Parties' initial litigation positions and final agreement on the disputed issues. The Parties request that the Commission treat the Settlements as unified, interrelated agreements and adopt them unconditionally and without modification. The Settling Parties state that they are aware of no statutory provision or prior Commission decision that would be contravened by the Generation Settlement.[12]

Under Rule 51.1(e), we will not approve a settlement unless the settlement is "reasonable in light of the whole record, consistent with the law, and in the public interest." In evaluating whether a settlement meets these criteria, we consider a variety of factors, including the strength of the applicant's case, the development of the record, including the extent to which discovery has been completed, whether the major issues are addressed by the settlement, and the reaction and/or support of interested parties. `

Because the Settlements presented are not all-party settlements subject to the guidance in D.92-12-019, we follow the criteria set forth in Rule 51.1(e), as explained in D.96-01-011.

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[12] The Settling Parties note that although PG&E requested that the Commission reconsider several of the findings adopted in D.00-02-046 in its showing, the Distribution Settlement takes no position on these policy issues.

> "[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (*Re Southern California Edison Company*, 64 CPUC 2d 241,267, citing D.94-04-088.)

Although the Settlements are not all-party settlements, they are supported by all parties who actively contested PG&E's forecasted TY 2003 revenue requirement request.[13] Only one party opposes the Settlements, and that party, DWR, takes issue with a single aspect of the Settlements. We address DWR's concern in Section 7.19, below.

In order to put the Settlements in context and determine whether they are in the public interest, we review the individual elements of the Settlements, focusing on the main points of contention. We do not base our conclusion on whether each one of the elements is, in and of itself, the optimal outcome. Instead, we consider whether the elements of the settlements, individually and taken as a whole, are consistent with the public interest. We do not attempt to summarize every nuance of the parties' individual positions, nor do we summarize minor issues.

We address issues not resolved by the Distribution Settlement or the Generation Settlement in Section 9, below.

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[13] We note that while AECA joined in the Distribution Settlement, it is unclear what issues, if any, were of concern to AECA because they did not file testimony or participate in the evidentiary hearings.

7. Terms of the Distribution Settlement

7.1 Total Revenue Requirement

The Distribution Settlement adopts a 2003 electric distribution revenue requirement of approximately $2,493 million and a gas distribution revenue requirement of $927 million. The Settling Parties agree that PG&E's revenues at present rates are $2,257.44 million for electric distribution and $874.895 million for gas distribution. Therefore, the Distribution Settlement would result in an increase from present rates of approximately $236 million for electric distribution and $52 million for gas distribution.

When combined with the Generation Settlement, the Distribution Settlement would result in a 2003 generation revenue requirement of approximately $912 million ($2003). Compared to present rates of $874.264 million for generation, the Settlements would provide for an increase of approximately $38 million, or 4.35%.

As shown in Table 2, below, the TY 2003 revenue requirement adopted by the Settlements represents a significant compromise on the part of all parties.

Table 2
Comparison of Settlement to PG&E and ORA Litigation Positions
(Millions of Dollars)

	PG&E Comparison Exhibit	ORA Comparison Exhibit	Settlement Agreement	PG&E exceeds Settlement	ORA exceeds Settlement
Electric	2710	2446	2493	217	(47)
Gas	982	909	927	55	(18)
Generation	944	895	912	32	(17)
Total				304	(82)

On an overall basis, we agree with the Settling Parties that the TY 2003 revenue requirements provided in the Settlements are reasonable in light of the record before us. The Settlements represent a significant reduction to PG&E's

TY 2003 revenue requirement request, and represent a reasonable compromise of the Settling Parties' positions regarding the issues resolved by the Settlement.

It is not clear that PG&E's revenue requirement would be as favorable to ratepayers through continued litigation as the revenue requirement provided in the Settlements, and as discussed further below, the Settlements resolve the issues within the zone of reasonableness such that we can find PG&E's rates to be just and reasonable.

7.2 Attrition

Attrition is the year-to-year decline in a utility's earnings caused by increased costs that are not offset by increased rates or sales. In order to protect utility shareholders from the effects of attrition to some extent, the Commission has adopted a ratemaking mechanism called the Attrition Rate Adjustment (ARA). The ARA mechanism was designed to "provide utilities with the reasonable opportunity of achieving their authorized rates of return during years in which they are not permitted under the Commission's rate case plan procedures to file for general rate relief but in which they still face volatile economic conditions." (D.85-12-076, Finding of Fact 1, 9 CPUC 2d 453,476.)

The traditional attrition mechanism provides for an advice letter filing, just prior to the attrition year, by the utility seeking increased rates based on the escalation of adopted TY GRC expense and rate base. A seven-year average of plant additions is used to account for rate base growth during the attrition period. The escalation rates are conventional indices such as the U.S. Department of Labor, Bureau of Labor Statistics' CPI, and DRI.

PG&E requested that we approve an ARA mechanism for the years 2004, 2005, and if applicable, 2006. PG&E's proposed mechanism was based on the traditional attrition mechanism adopted in D.85-12-076, and modified in

D.92-12-057, with two additional components. First, for distribution attrition, PG&E proposed to modify the attrition mechanism to account for a higher-than-usual increase to medical benefits costs. PG&E also proposed to replace the Materials and Services Index (MSI) previously used to forecast non-labor escalation rates with individual price indices drawn from DRI/WEFA's Utility Cost Information Service (UCIS).[14]

Second, for generation attrition, PG&E proposed to modify the attrition mechanism to reflect its anticipated "ramp-up" in generation capital spending and O&M expense. PG&E's proposed method results in capital additions that significantly exceed the amount resulting from a seven-year average.

PG&E's proposed attrition mechanism would result in 2004, 2005, and 2006 revenue requirement increases of $74 million, $83 million, and $82 million for electric distribution and $28 million, $31 million, and $31 million for gas distribution. PG&E's proposal would result in estimated generation attrition increases of $56 million, $9 million, and $33 million for 2004, 2005, and 2006, respectively.

For distribution attrition, ORA supported PG&E's method. For generation attrition, ORA also approved PG&E's proposed method – but not PG&E's forecast of 2004 and 2005 capital expenditures. Instead, ORA proposed that the Commission use PG&E's 2003 forecast of electric generation capital additions. ORA also proposed an additional year of attrition in 2006 and deferral of PG&E's next GRC to test year 2007. (Exhibit 304, p. 19-8.) ORA agreed with PG&E's

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[14] DRI/WEFA is an internationally recognized economic forecasting firm formed from a merger of WEFA and Standard and Poors' DRI.

request to file for attrition through an advice letter for attrition years 2004 and 2005, but proposed that PG&E be allowed the option to file an application rather than an advice letter for the 2006 attrition year if the traditional ARA mechanism did not allow PG&E a reasonable opportunity to earn the authorized rate of return.

Aglet advocated an attrition method that would calculate a revenue requirement for 2005 based on the 2003 revenue requirement times one year of forecast change in CPI. Aglet requested that the Commission deny PG&E's request for 2004 and 2006 revenue requirement adjustments, arguing that in light of the continuing low inflation and interest rates, a single distribution attrition allowance in 2005 would be appropriate. As for the change in the method of forecasting capital additions, Aglet argued that PG&E's request was unfairly slanted toward higher rates by isolating operational areas where it intends to spend more than prior year attrition formulas would indicate while providing no offsetting revenue reductions in areas where PG&E may intend to spend less. Aglet recommended that we require PG&E to file separate applications supporting its request for Diablo Canyon refueling outage adjustments and the Low Pressure Turbine Rotor Replacement project (LPTRR). Like ORA, Aglet supported deferral of PG&E's next GRC. (Exhibit 550, p. 13-14 and 15-17.)

The Distribution Settlement reflects the Settling Parties' agreement to defer the test year for PG&E's next GRC until 2007, and to provide PG&E attrition adjustments for 2004, 2005, and 2006, based upon an agreed-upon formula and implemented through advice letter filings. The proposed annual electric and gas distribution attrition adjustments for 2004 and 2005 would be equal to the previous year's authorized revenue requirement times the forecast change in the CPI for All Urban Consumers.[15] For 2006, the proposed annual electric and gas distribution attrition adjustments would be equal to the previous year's authorized revenue requirements times the forecast change in CPI-All Urban Consumers plus one percent.

Notwithstanding the forecast change in CPI-All Urban Consumers, the Distribution Settlement provides for minimum and maximum revenue requirement attrition adjustments as follows:

	2004	**2005**	**2006**
Minimum	2.0%	2.25%	3.0%
Maximum	3.0%	3.25%	4.0%

The Distribution Settlement would result in 2004, 2005, and 2006 estimated attrition increases of $62 million, $64 million, and $89 million for electric distribution and $23 million, $24 million, and $33 million for gas distribution.[16]

The Generation Settlement also provides for annual electric generation attrition increases for 2004, 2005, and 2006, equal to the previous year authorized revenue requirement times the forecast change in CPI-All Urban Consumers,

[15] The CPI change equals the latest Global Insight forecast prior to filing (for example October 2003, for year 2004) divided by the concurrent forecast for the current year (for example October 2003, for year 2003), minus one.

[16] Agreement Comparison Exhibit, p. 3-2. Based upon CPI of 2.5%, 2.5%, and 2.4% in 2004, 2005, and 2006, respectively, consistent with the underlying escalation rates assumed in this GRC. Actual CPI forecasts to be used to calculate attrition would be determined in October of each year for the following year.

including a minimum increase of 1.5% and a maximum of 3% for 2004 and 2005, and an additional 1% for 2006.

Under the Generation Settlement, the base revenue requirement for Diablo Canyon includes one refueling outage. If PG&E forecasts a second refueling outage in any one year, the authorized revenue requirement would be increased by $32 million ($2003) per refueling outage, adjusted for CPI using the same formula described above for attrition adjustments. The Generation Settlement also authorizes $3 million ($2003) per year for 2004, 2005, and 2006, for additional security costs at Diablo Canyon, plus an attrition allowance using the same formula described above for attrition adjustments. This would result in an estimated increase of $56 million for 2004, decrease of $9 million in 2003, and an increase of $33 million in 2006.

7.3 Discussion

The attrition mechanism originated in SoCalGas' 1981 GRC (D.92497, 4 CPUC2d 725,770 (1980)). An attrition adjustment for PG&E was first adopted in PG&E's TY 1982 GRC. In that decision, the Commission found that "an attrition mechanism is a necessity in this period, where the economy is unpredictable and volatile. We believe the adoption of indexing under these circumstances is a necessity to assure that PG&E will be able to recover its costs and also to protect ratepayers from possible overestimates of expenses."

In the same decision, at PG&E's request, the Commission adopted a new rate mechanism called the Electric Revenue Adjustment Mechanism (ERAM). The ERAM functioned in the same manner as the balancing accounts adopted to implement Public Utilities Code Section 739.10, discussed in Section 7.20 below, ensuring the full recovery of electric revenue requirements regardless of actual sales.

In D.85-12-076, the Commission reconsidered the attrition mechanism and declined to eliminate it at that time, finding that even though attrition may create a "disincentive to manage cost escalation and seek cost efficiencies,"…a "three year rate case cycle with but one year of rate relief would not give the utilities a reasonable opportunity to earn their authorized rate of return." (19 CPUC2d, 453, 456.) The Commission also considered and rejected a staff proposal to apply an earnings test to the calculation of attrition year revenue requirements.

The Commission has since approved attrition adjustments in four of PG&E's GRCs (D.86-12-095, D.89-12-057, D.92-12-057, and D.00-02-046). In D.89-12-057, the Commission rejected PG&E's request to adjust the seven-year average to reflect a higher than usual increase in capital additions, finding that although the average approach may understate the costs of some projects and overstate the costs of other projects, the overall outcome is fair. In D.00-02-046, the Commission denied PG&E's request for an attrition increase for 2000, finding that neither high inflation, nor unpredictable changes in financial markets warranted attrition relief in that year, but allowed PG&E to file an application for attrition in 2001.

In this case, as in previous GRCs, the question we consider when deciding whether and through what method to grant attrition relief is whether the utility will have a reasonable opportunity to earn its authorized rate of return in the attrition year based on current and forecast economic conditions. PG&E acknowledges that this is the critical question, stating "if PG&E believes that it has the opportunity to earn its rate of return in a non-GRC year without attrition, then PG&E should, and has historically, forgone making a request for attrition." (Exhibit 24, p. 5-6.)

PG&E and Aglet each refer us to particular periods during which the Commission has granted or denied attrition as suits their objective. PG&E pointed to a twelve-year period during which the Commission has granted attrition in all but two of the years. Aglet pointed to the more recent five-year period in which the Commission has granted attrition relief only once. Viewed from either perspective, this history is consistent with our policy that attrition relief is not an entitlement or a method of insulating the company from the economic pressures which all businesses experience. This history is also consistent with the our prior finding that "Neither the Constitution nor case law has ever required automatic rate increases between general rate case applications." (D.93-12-043, 52 CPUC 2d 471,492.)

The attrition mechanism proposed in the Settlements would grant PG&E attrition adjustments in each of the years 2004, 2005, and 2006, with the adjustment tied to the level of inflation, as measured by the CPI- All Urban Consumers. The annual changes in the adopted revenue requirement would be calculated by escalating the previous year authorized Revenue Requirement using CPI. The attrition mechanism would also "guarantee" a minimum attrition adjustment regardless of the level of inflation or the level of the utility's earnings.

As with the other areas of the Settlements, the Settling Parties assert that the attrition agreement is reasonable because it represents a compromise between the positions of the parties, and because the revenue requirement adjustments calculated by the CPI method are estimated to be less than the revenue requirements that would have been calculated by PG&E's proposed model under a variety of inflation rates. However, the parties' agreement to the particular number or approach is not sufficient to deem it reasonable; we must be able to find the settlement reasonable in light of the whole record in order to approve it.

We believe that approving a "minimum" increase in the adopted revenue requirement regardless of whether or not PG&E has been able to earn its authorized rate of return is inconsistent with the Commission's policy that attrition adjustment should reflect an "opportunity" to earn the authorized rate of return and not a "guarantee." Taken to an extreme, approval of the proposal would grant PG&E a guaranteed increase in revenue requirement even in the event of deflation, an outcome that is clearly unreasonable.

Although we are generally reluctant to alter the results of a good faith negotiation process, we must do so if we find that the public interest is in jeopardy, as is the case here. We approve the framework offered by the Settling Parties that provides for automatic attrition adjustments for each of the attrition years 2004, 2005, and 2006, tied to the level of CPI-All Urban Consumers, but modify the Distribution Settlement to eliminate the provision for a "minimum" attrition increase. We do not believe that this modification deprives PG&E of the opportunity to earn its authorized rate of return. Although initially PG&E requested a higher-than-usual forecast of generation capital additions, according to PG&E witness Berman, the increase in the generation capital additions forecast was primarily associated with reliability work in hydro operations and the replacement of low-pressure turbine rotors in nuclear generation.
(RT 1494:11-15.) As part of the Generation Settlement, the Settling Parties have agreed that PG&E's proposed low-pressure turbine rotor replacement projects

will be reviewed as part of the TY 2007 GRC and PG&E will file a separate application for the steam generator replacement project.[17] The Generation Settlement also includes PG&E's agreement to remove the Selective Catalytic Reduction Project from its forecast.

We find that authorizing an automatic CPI–based attrition mechanism by advice letter for the years 2004, 2005, and 2006, including a one percent adder to the attrition adjustment in 2006, as well as specific adjustments for additional refueling outages and increased security costs at Diablo Canyon, will provide PG&E with a reasonable opportunity to earn its rate of return in the attrition years, consistent with our attrition policy. Although the adopted attrition mechanism will significantly reduce the risk PG&E will face in the attrition years, it will not completely eliminate risk. This is also consistent with our attrition policy.

7.4 Administrative and General (A&G) Expense

7.4.1 Introduction

A&G expenses are general expenses not directly chargeable to any specific utility function. They include general office labor and supply expenses and items such as insurance, casualty payments, pensions and benefit expenses, consultant fees, regulatory expenses, and stock and bond expenses.

PG&E, ORA and TURN all took positions on A&G expense issues. Based on a detailed audit of PG&E's A&G expense forecast, ORA recommended adjustments to PG&E's TY 2003 A&G expense forecast in the following areas: the allocation of holding company costs to the utility, Corporate Services

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[17] PG&E has now filed this application, A.04-01-009.

Department total costs and the allocation of those costs to capital, below-the-line (*e.g.*, bankruptcy-related costs) or to affiliates, the Performance Incentive Plan, Benefits (including medical, dental, and vision plans, service awards, employee relocation, and tuition reimbursement), Property Insurance, Third Party Claims, Directors and Officers Liability insurance, seismic upgrade projects, and various accounting adjustments. PG&E and ORA also differed on the amount of various A&G costs to capitalize.

TURN also recommended reductions to PG&E's A&G expenses in the areas of Holding Company costs and allocation of additional costs below-the-line for the Revenue Requirements, Internal and External Communications, and Affiliate Rules and Regulatory Compliance Departments.

TURN generally agreed with ORA's recommended adjustments, and offered additional testimony in areas where TURN recommended further adjustments to PG&E's request. For example, TURN would allocate a small percentage of the costs of the Internal and External Communications Department to below-the-line on the basis that ratepayers should not be funding anti-municipalization efforts. TURN notes that a number of the publications developed by this department related to municipalization. In the Revenue Requirements Department, TURN recommended that a normalization adjustment is required to reduce GRC contract expenses to take into account that a GRC is not filed each year. TURN's adjustment would provide for a contract cost of approximately $1.3 million, compared to PG&E's requested $2.58 million. TURN also recommended that the cost of affiliate compliance for non-tariffed products services should be allocated on a 50/50 basis between ratepayers and shareholders, instead of entirely to ratepayers as ORA proposed. TURN noted that the difference in allocation is small, only $28,225, but the principle of assuring that shareholders pay all relevant affiliate compliance costs is important.

TURN's position on A&G expense is $853,700 lower than ORA's Comparison Exhibit position. (Exhibit 100, p. 3-6.) The following table compares PG&E's A&G request and ORA's recommendations.

Table 3
PG&E's and ORA's Positions on Total Utility A&G Expenses[18]
(Thousands of 2000 dollars)

Account	Description	PG&E	ORA	Difference
920	Salaries	139,035	112,416	(26,619)
921	Office Supplies and Expenses	23,334	17,276	(6,059)
922	A&G Capital Transfer	(20,960)	(17,066)	3,893
923	Outside Services	116,979	60,161	(56,818)
924	Property Insurance	15,531	10,859	(4,492)
925	Injuries and Damages	75,970	70,458	(5,511)
926	Pensions and Benefits	287,917	192,843	(95,074)
928	Regulatory Commission Expenses	(0)	(0)	(0)
930	Miscellaneous General Expenses	86,909	86,909	(0)
935	Maintenance of General Plant	11,233	6,310	(4,922)
	Total A&G Expenses (2000 $)	735,767	540,165	(195,602)

As can be seen in Table 3, the largest differences between the two forecasts appear in Account 920 (Salaries), Account 923 (Outside Services), and Account 926 (Pensions and Benefits). Account 923 includes the charges to PG&E from PG&E Corporation, its parent company (the holding company). The difference in Account 926 relates primarily to PG&E's requested contribution to the Retirement Plan trust, discussed in Section 9.1 below.

ORA recommended a reduction of $26,619,000 in Account 920 primarily related to PG&E's Performance Incentive Plan (PIP) forecast. The PIP is a short-term incentive pay plan that covers approximately one-third of PG&E's workforce. PIP payments are earned during the plan year and paid in March of the following year. The annual payments are based on the employee's

[18] Exhibit 100, App. A, page 24.

participation rate and the PIP score for the department in which the employee works. The participation rate is a fixed percentage of the employee's base pay, and varies by employee category. The PIP score can range from 0.0 to 2.0 and reflects the department's actual performance compared to annual performance measures. PG&E requested $139,035,000 in Account 920, of which $41,622,000 ($2000) is PG&E's 2003 PIP forecast. ORA recommended adjusting Account 920 to require shareholders to fund 50% of the PG&E's forecast PIP expenses, consistent with the Commission's decision in D.00-02-046.

ORA recommended a reduction of $56,818,000 in Account 923, the majority of which ($40 million) is related to ORA's contention that PG&E failed to comply with the Commission's holding company policies as explained and affirmed in D.00-02-046. In D.00-02-046, the Commission found that PG&E does not benefit from the non-regulated activities of PG&E Corporation or PG&E's affiliates and that it is reasonable to allow in utility rates only holding company charges that reflect services that are clearly needed by the utility and that are provided efficiently, without duplication of effort. ORA maintains that PG&E's holding company cost allocations result in a significantly overstated A&G expense forecast, by including in the forecast costs for services that are not clearly needed by the utility as well as costs for services that provide no benefit to the utility. (Exhibit 306, p. 1-3.) ORA recommended adjustments include, but are not limited to the following:

- Allocating 100% of the Holding Company General Counsel Department costs to affiliates to reflect that the Utility has its own SVP General Counsel and a Deputy General Counsel. (Exhibit 306 p. 7-17.)
- Reducing PG&E's proposed allocation of Holding Company Law Department costs to the Utility from 75.98% to 20%. (Exhibit 306 p. 7-24.)

- Allocating 100% of the Holding Company CFO Department labor and material costs to affiliates to reflect the fact that PG&E has its own CFO and does not need to purchase financial management services from the utility. (Exhibit 306 p. 8-6.)
- Reducing the utility allocation of the Holding Company Human Resources department from PG&E's allocation of 89.5% to 28.32% to reflect the actual activities of the department.
- Reducing the utility allocation of Corporate Accounting costs by 68.85% to reflect the fact that the need for the Holding Company stand-alone general ledger, consolidated SEC reporting, and separate Holding Company budget reporting functions are incremental requirements directly attributable to the formation of the Holding Company. (Exhibit 306 p. 8-15.)

ORA also noted that PG&E expects to continue to incur substantial bankruptcy litigation and POR costs in TY 2003. Although PG&E's stated policy is to charge incremental bankruptcy and POR costs to shareholder funded below-the-line accounts, ORA believes that PG&E failed to allocate all of the incremental costs attributable to its bankruptcy proceeding and POR implementation activities to the below-the-line accounts. ORA also recommended several adjustments to the below-the-line category related to the costs of public relations activities designed to enhance PG&E's general corporate reputation, and costs associated with influencing elections and the decisions of elected government officials. ORA's recommended allocation factors allocate $5.5 million more to the below-the-line accounts for utility departments than PG&E's request. Examples of ORA's allocation adjustments include:

- Increasing the allocation of the Media Relations Department costs to the below-the-line category by 15.73%

to remove incremental POR costs and the costs of corporate image enhancement.

- Allocated 58.28% of the VP Governmental Relations Department's costs to the below-the-line category to eliminate political advocacy, image enhancement and incremental bankruptcy costs.
- Increased the below-the-line allocation of the Local Governmental Relations Department to 31.4%.
- Allocated an additional 35.6 % of the External Relations Department's cost below-the line to reflect the costs of political advocacy and image enhancement. ORA notes that key activities of the External Relations Department include organizing support from individuals and organizations for company initiatives such as the POR, GRC and legislation.

ORA also argued that PG&E's capital allocations in its TY 2003 forecast are inconsistent with the incremental cost approach adopted in D.00-02-046 and significantly overstate A&G expense. ORA explained that under the adopted 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. (D.00-02-046, *mimeo.*, p. 287.) ORA recommended specific adjustments to utility department labor and materials costs resulting in the allocation of $5.6 million more ($2000) to capital than PG&E's factors. Examples of specific adjustments include:

- ORA allocated 14.42% of the Benefits Department cost to capital to reflect the fact that the activities in this department are a function of employee levels. Construction activities accounted for 31.3% of PG&E's total labor costs in 2002; therefore, PG&E's workforce would be approximately 30% lower in the absence of its ongoing construction program.

- ORA allocated 14.29% of the Compensation Department cost to capital to reflect the fact that a reduction in construction activities would reduce PG&E's workforce, resulting in a reduction in the compensation workload. PG&E allocated 0% of this Department's cost to capital.
- ORA also argued that PG&E made an error in its allocation of PIP costs to construction, resulting in an overstatement of A&G expenses by $10.6 million. PG&E allocated 6.76% of its 2003 PIP forecast to capital. ORA argues that a correct application of the labor burden procedure (using O&M labor to allocate costs) results in the capitalization of approximately 32% of PIP costs at the target payout of 1.0 in 2002.

ORA also recommended several forecast adjustments related to labor, materials, and contract amounts. The labor adjustments reflect ORA's position that PG&E's forecasts for 9 of the 42 utility departments reflect staffing levels that significantly exceed historical and current levels. For each staffing adjustment, ORA also made a corresponding adjustment to materials.

7.4.2 Settlement Amount

The Distribution Settlement would adopt overall (total utility) A&G expense of $585 million ($2000). This compares to PG&E's total A&G forecast of $735.8 million as presented in the Joint Comparison Exhibit. (Exhibit 100, p. A-24) and ORA's recommended overall A&G expenses of $540 million.

The Settlement amount for A&G expense does not include PG&E's request for the pension contribution.[19] After adjusting to remove the amount associated with PG&E's pension fund request, the Distribution Settlement represents a

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[19] The Distribution Settlement does include an amount for net wage-related pension expense of $1.7 million.

$64 million reduction from PG&E's request in total A&G and an increase of $45 million in costs compared to ORA's position.[20] The Settlement would also adopt specific capitalization rates for the A&G accounts to which they apply.[21]

7.4.3 Discussion

The difference between the agreed-upon amount for A&G expenses, $585 million, and the parties' positions, is extremely large, ranging from a $64 million reduction to PG&E's request to a $45 million increase in ORA's recommendation. That the Settling Parties were able to bridge this gap and reach agreement is remarkable.

While ORA's and TURN's analyses have cast substantial doubt on the reasonableness of PG&E's A&G forecast, all of ORA's and TURN's recommendations are not equally persuasive. The primary areas of concern to ORA and TURN include: (1) the allocating of holding company costs to the utility, (2) the allocation of below-the-line costs to the utility, (3) the request for

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[20] This figure is derived by subtracting the $585 million agreed upon by the Parties from the $735.8 million shown as PG&E's position in the Comparison Exhibit (Ex. 100, App. A, p. 24) and then subtracting the $86.5 million expense portion of the $128.6 million pension fund request. (Ex. 100, p. F-28, Line 57.)

[21] Section 3.1.3 of the Distribution Settlement adopts the 24% factor for Account 920 (PIP Capitalization) as set forth by PG&E in its rebuttal testimony and agreed to by ORA during the hearings. (Ex. 22, p. 2-3; Tr. 3148, ORA/Harpster.) The 10.9%, 7.6%, and 1.9% factors for Account 920 (Salaries), Account 921 (Office Supplies), and 923 (Outside Services), respectively, are the weighted average results of the A&G Study capitalization rates (PG&E column) set forth on pages F-73 through F-145 of Ex. 100. The 32.22% factor for Workers Compensation in Account 925 and for all Pensions and Benefits in Account 926, as well as the 19.9% factor for Third Party Claims in Account 925, were recommended by ORA (Ex. 306, pp. 11-4, 11-6, and 11-9) and agreed to by PG&E.

ratepayer funding of 100% of the PIP costs, (4) certain of PG&E's allocations to capital, and (5) forecast adjustments.

PG&E admits that its forecast includes the costs of certain items not adopted in PG&E's last GRC (*e.g.* a portion of Performance Incentive Plan payments and certain support costs billed by PG&E Corporation) but argues that its showing in the instant proceeding clearly demonstrates that these costs are reasonable.

ORA does not question that the holding company provides, in certain areas, services that are both needed by the utility and that benefit the utility, but nevertheless contends that certain adjustments are necessary. PG&E takes issue with ORA's function-by-function adjustments to PG&E's holding company allocations. PG&E contends that ORA's analysis is fundamentally unfair because it calculates the incremental costs that would be avoided but for the holding company without giving due consideration to the benefits created by the formation of the holding company. In rebuttal, PG&E provided general estimates of the cost that the utility would have to incur to replace the services provided by the holding company if the holding company did not exist. Based on these estimates, PG&E argues that the existence of the holding company provides substantial benefits in terms of economies of scale.

When tested under cross-examination, certain of PG&E's estimates were not convincing. For example, when asked why the utility would need to add four individuals in the relocation services section of the Human Resources department to perform less work than is currently being performed by three individuals in the holding company Human Resources department, PG&E witness Clark simply responded that four individuals represents the staffing level initially transferred to the holding company in 1998, (RT 2510:8-9) without adjusting for potential changes in the number of employees since 1998. Furthermore, PG&E failed to provide any evidence corroborating its estimates.

We also question PG&E's contention that because it cannot have shared services among subsidiaries without consolidating subsidiaries, and because PG&E benefits from the efficiencies associated with those shared services, PG&E should share in the cost of the consolidation. We have already held that the utility does not benefit from the existence of the Holding Company. This fact has become even more evident in light of the unwillingness of the Holding Company to provide any financial support to the utility during the energy crisis.

We have held that it is appropriate for the utility to pay for those services provided by the Holding Company that are both needed, and that are provided efficiently, without duplication of effort. The "consolidation" services provided by certain departments fail the first test, *i.e.*, they are not independently needed by the utility.

PG&E also argued that ORA's analysis unfairly confuses titles with functions. We agree with the general premise of PG&E's argument, that is, the fact that two individuals carry the same title or work in departments with the same name does not mean that those individuals perform the same tasks or functions, but note that the burden remains on PG&E to demonstrate that a title is indeed all they share.

Notwithstanding the concerns raised by ORA and TURN's initial testimony, we are willing to approve the A&G element as part of the broader Distribution Settlement. It is clear that the parties have each made substantial concessions relative to their individual positions in order to achieve the Settlement. One of the factors we use in evaluating the reasonableness of a settlement is whether the interests of the parties supporting the settlement are fairly reflective of the interests of the parties that would be affected by the settlement. In this case, the Distribution Settlement commands the support of all parties taking positions on PG&E's TY 2003 revenue requirement request, including those parties challenging PG&E's A&G forecast. Moreover, the Settling Parties represent residential and small commercial customers of PG&E; the parties that are likely to be the most sensitive to any revenue or rate increases. When parties with very different viewpoints agree on a solution to a problem, it is an indication that it is a reasonable proposal.

Because the A&G settlement represents a sizable reduction to PG&E's request, that is part of a broader settlement, representing various trade-offs by all the parties, we find it reasonable in light of the record.

7.5 Unbundling of A&G Expenses

In Section 3.1.4 of the Agreement, the Settling Parties agree that it is more efficient to litigate common costs like A&G expenses only once, in the GRC, and then to use the results in other CPUC proceedings, rather than re-litigating these common A&G expenses multiple times. The Settling Parties request that A&G expenses allocated to Unbundled Cost Categories (UCCs) adopted in this 2003 GRC be used in determining the A&G expenses in related proceedings in 2003 and future years until the 2007 test year GRC, if those proceedings would otherwise require litigation of A&G expenses. The Settling Parties maintain that this approach would ensure consistent recovery of the A&G expenses approved in this GRC.[22] The affected UCCs and related proceedings are: Gas Transmission (Gas Accord II and Gas Accord III); Humboldt (Nuclear Decommissioning Cost Triennial Proceeding); Gas Public Purpose Programs (PPP) and Electric PPP (various gas and electric PPP filings.)

In addition, the Settling Parties agree that, to the extent that Commission decisions in 2004 through 2006 on PPP include less A&G expense than the amounts allocated to PPP UCCs in this Agreement, any shortfall would be recovered through GRC distribution attrition revenues. The Settling Parties agree that the revenue requirements included in this Agreement are sufficient to address the issue of a possible shortfall in electric PPP revenues in 2003.[23]

We accept the Settling Parties' approach as reasonable; however, we remind the Parties that we cannot bind future Commissions to this approach. Pub. Util. Code § 1708 provides that, with proper notice and opportunity to be heard, a future Commission may rescind, alter, or amend previous decisions to the extent deemed necessary to provide for just and reasonable rates.

7.6 Nuclear Decommissioning Trust Administrative Fees

PG&E's Application included $2.97 million of nuclear decommissioning trust fund administrative fees charged to A&G Account 930, Miscellaneous and General Expense. TURN initially argued that this expense should be directly

[22] This Agreement does not require Parties to support the use of forecasts, as opposed to escalation methods, in other cases. For example, some Parties may argue in a Gas Accord proceeding that simple escalation is preferable to forecasting a new test year.

[23] PG&E reserved the right to argue in its brief that if PG&E's position on pension contribution is upheld, then there is a shortfall in the PPP (and possibly other non-GRC UCCs) revenue requirement in 2003.

assigned to a "nuclear decommissioning" UCC rather than the "generation UCC where PG&E and ORA have assigned it." (Exhibit 405, p. 15.) PG&E explained on rebuttal that TURN's recommendation would effectively eliminate PG&E's opportunity to recover these costs through 2005 by shifting them to an already completed proceeding, A.02-03-020, which did not include them.

In response to PG&E's rebuttal, TURN proposed and PG&E agreed to a "Joint Recommendation of PG&E and TURN--Account 930 Nuclear Decommissioning Trust Fund A&G Expenses." (Exhibit 426.) The joint recommendation provides that the $2.97 million ($2000) in this cost category will remain classified to generation UCCs in this GRC. In its next triennial nuclear decommissioning proceeding, PG&E will include this cost as a nuclear decommissioning cost in its application, and will include in its application in that case a provision to reduce the generation revenue requirement by an equal and offsetting amount.

PG&E and TURN agree to jointly propose a class allocation of these nuclear decommissioning trust fund expenses in Phase 2 of this GRC that is consistent with the allocation of nuclear decommissioning costs.

The Distribution Settlement adopts the joint recommendation that resolves the issue raised by TURN. The Joint Recommendation is a reasonable compromise of the positions presented by the Settling Parties, and is fully supported by the evidence in the record.

7.7 Distribution Operations and Maintenance Expense

Distribution Operations and Maintenance (O&M) expenses cover the cost of operating and maintaining PG&E's electric and gas distribution systems. PG&E requested distribution O&M expenses of $399.873 million electric and $119.940 million gas. ORA recommended O&M expenses of $382.806 million for electric distribution and $116.949 million for gas distribution. (Exhibit 100, pp. 2-4; 2-15.)

ORA recommended adjustments to PG&E's requested electric distribution O&M expenses in the following MWCs: Operate Distribution System

(MWC BA), Line Patrols and Inspections (MWC BF), Preventive Maintenance (MWC BG), Work Required of Others (MWC EW), Test and Treat and Pole Restoration (MWC GA), and Vegetation Management (MWC HN). (Exhibit 100, pp. C-1 to C-3.) ORA requested adjustments to PG&E requested expenses for gas distribution O&M in the following MWCs: Catholic Protection (MWC DG), Install Meters and Devices (MWC EY), Preventative Maintenance (MWC FH), and Perform Maintenance to Correct Failure (MWC FI). (Exhibit 100, C-4-C-5.) ORA stated that its adjustments were focused on MWCs for which PG&E had requested "dramatic" increases in incremental spending without providing sufficient support for its requests. ORA also recommended adjustments in areas where PG&E "proposed additional funding for maintenance activities that were previously funded." (Exhibit 303, p.6-8.)

TURN recommended further reductions compared to the expense level recommended by ORA of approximately $8.85 million ($2000 FERC). TURN proposed expense reductions in the following areas: CAISO-Ordered Stage 3 Events (MWC BA), Corrective Maintenance (MWC BH), and Customer Connections (MWC EV). ORA and TURN disagreed with some of PG&E's underlying estimation methodologies based on anticipated units of work and forecast unit costs, and differed with PG&E on how to use historical data to forecast future expenses.

The Distribution Settlement adopts 2003 distribution O&M expenses of $391.5 million electric and $118.5 million gas ($2000 FERC). The Distribution Settlement also adopts a Vegetation Management expense (included in the above electric total) of $124.7 million. This amount includes funding for the Vegetation Management Quality Assurance Program, but eliminates the requirement adopted in D.00-02-046 that shareholders share in the cost of this program. The one-way balancing account for Vegetation Management and the associated Quality Assurance Plan would continue in effect, as would the tree removal program. The $124.7 million ($2000 FERC) for the Vegetation Management account represents a compromise between PG&E's position of $126.857 million and ORA's position of $118.122 million.

The Settling Parties' agreement on O&M expenses falls between the litigation positions of each of the Settling Parties. The settlement represents a reasonable compromise, at a high level, between the positions held by the Settling Parties on specific detailed issues. The Settling Parties state that their high-level agreement is not intended to imply any specific resolution of issues at a detailed level, with the exception of the one way balancing account for Vegetation Management, nor it is intended to create any future precedent.

7.8 Customer Accounts and Services Expense

PG&E's Customer Accounts and Services activities include the processes, technology, and people that together form the vital communication link between PG&E and its 4.7 million electric and 3.8 million gas customers. PG&E TY 2003 forecast for distribution Customer Accounts expenses was $206.025 million electric and $159.492 million gas, compared to ORA's estimate of $194.982 million electric and $151.129 million gas. ($2000 FERC.)

PG&E's forecast for distribution Customer Services expenses was $3.662 million electric and $3.618 million gas, whereas ORA estimated $1.912 million electric and $3.515 million gas.

TURN and Aglet also conducted detailed analysis of PG&E's proposed Customer Accounts and Services expenses by MWC. TURN recommended reductions in PG&E's Customer Accounts and Services expenses of approximately $16.1 million.[24] A portion of these reductions overlaps with the recommendations of ORA and Aglet. Aglet recommended reductions in PG&E's Customer Accounts and Services expenses of approximately $4.2 million;[25] a portion of these reductions overlap with the recommendations of ORA and TURN. TURN proposed expense reductions in the following areas: Customer Retention (MWC FK), Utility Operations (UO) Internet Projects (MWC AB), and Customer Information Systems (MWC BJ). Aglet proposed expense reductions in the following areas: Meter Reading (MWC AR), Customer Retention (MWC FK), and Economic Development (MWC FK).

The most significant areas of controversy affecting the forecast of 2003 expense included: the forecast ongoing expense required to operate PG&E's Customer Information System; whether PG&E should recover in rates the costs of customer retention programs; whether PG&E should recover in rates the costs of programs to attract customers to PG&E's service area in conjunction with state and regional development efforts; whether PG&E's per customer cost to serve Commercial, Industrial and Agricultural customers is higher than Southern California Edison Company's; and the amount of overtime PG&E will need, principally in the customer services area, for 2003 and beyond.

The Settlement adopts Customer Accounts distribution expenses of $199.9 million electric and $154.7 million gas and Customer Services distribution expenses of $1.363 million electric and $3.483 million gas. The Customer Services

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[24] $2000 FERC.

[25] $2000 FERC.

forecast reflects a zero expense amount in Account 912 for customer retention and economic development.

The Settling Parties' agreement on Customer Accounts and Services expenses represents a compromise from the parties' litigation positions and is fully supported by the record developed in this proceeding.

7.9 Line Extension Administration

PG&E requested $10.163 million for Major Work Category (MWC) EV (Customer Connection Expenses) ($5.590 million allocated to the Electric Distribution and $4.573 million allocated to Gas Distribution). TURN proposed that PG&E recover $4.332 million, arguing that the "majority of costs contained in this expense account are for tasks associated with connecting new customers to PG&E's system and, therefore, should be subject to the line extension allowances (and considered as a portion of PG&E's forecast for MWC 16)." (Exhibit 401, p. 4.)

The Distribution Settlement provides that PG&E will, beginning in 2004, charge processing expenses to new customer connection applicants in a manner to be determined by PG&E. In addition, non-residential customer revenue estimate expenses incurred in 2004 and subsequent years will be charged to new customer connection applicants in a manner to be determined by PG&E. Finally, new customer connection process improvement expense incurred in 2004 and in subsequent years will be included in the overheads charged to all new application projects.

This resolution is consistent with the record and represents a reasonable compromise of the litigation positions of TURN and PG&E.

7.10 Uncollectibles

PG&E uses an "uncollectibles factor" to forecast the expense associated with uncollectible utility revenues. This forecast is included in FERC Account 904. The uncollectibles factor the Commission last adopted for PG&E is 0.267 %. In this case, PG&E proposed a lower factor of: 0.250 %. PG&E calculated its proposed factor using the five-year average from 1997-2001, 0.209 %, and adding an adjustment of 0.041 % to take into account the "poor state of the economy as evidenced by the increase in the number of bankruptcy filings that have occurred in recent years." (Exhibit 6, p. 4-7 to 4-8.)

Aglet recommended a factor of 0.182 percent, an amount equal to the recorded, unweighted three-year average for 1999-2000. Aglet argued PG&E's adjustment of 0.041 % is unreasonable because PG&E had not demonstrated that an increased number of bankruptcy filings indicate that more people are unable to pay their bills.

In Section 3.4 of the Distribution Settlement, the Parties agree to an uncollectibles factor of 0.200 %. This agreement is reasonable and is fully supported by the record.

7.11 Depreciation

The purpose of depreciation expense is to distribute the recovery of the original cost of fixed capital assets less estimated net salvage over the useful life of the assets. Depreciation expense is a function of plant in service, the rate at which various classes of plant are expected to depreciate (service lives), and estimated net salvage. Public Utilities Code Section 795 empowers the Commission to "ascertain and by order fix the proper and adequate rates of depreciation of the several classes of property of each public utility."

PG&E requested that the Commission use the depreciation parameters developed in its depreciation study to determine the electric and gas depreciation rates. The depreciation study proposed new depreciation parameters (*i.e.*, average service lives, curve type, and net salvage percents) based on a review of PG&E's historical records, company practices with respect to plant maintenance, and expected future events that may affect service life and net salvage. Based on the depreciation study, PG&E proposed changes to net salvage rate, average service life, and mortality curve.

The depreciation parameters proposed by PG&E translate into a TY 2003 forecast of $564.7 million for electric distribution-related depreciation expense, a 49.4 % increase over the $377.9 million level adopted in PG&E's last GRC. PG&E also forecast $179.4 million for gas distribution-related depreciation expense, a 15.1 % decrease in the $211.3 million adopted previously.

TURN and ORA also presented testimony on depreciation issues. ORA recommended that the Commission reject PG&E's proposed changes to electric distribution net salvage percentages.[26] Instead, ORA argued, the net salvage percentages for electric distribution should remain at their currently authorized levels. ORA's position reflected its concern regarding PG&E's accounting treatment of monies received from third parties, crediting reimbursed retirements to the cost of replacement, rather than including it with net salvage. (Exhibit 304, p.17-8.) ORA's position also reflected its concern that not only are

[26] Due to staffing constraints and the relative amount of the increase requested, ORA focused on the requested change to net salvage percentages and did not analyze PG&E's proposed changes to average service lives.

the proposed net salvage percentages too high, but currently authorized net salvage percentages may also be too high. To explain the basis for its concern, ORA provided the following comparison of the net salvage received in rates to the net salvage actually spent over the ten-year period from 1993-2002:

Table 4
Net Salvage Dollars Received vs. Actually Spent[27]
(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	

[27] Exhibit 304, p. 17-14, Table 17-3. Net salvage amounts associated with allocated plant (Common, general) have been excluded from both the "Received in Rates" and "Actually Spent" lines, however, these amount are small in comparison and do not affect the conclusion that PG&E is receiving more net salvage dollars than it is spending.

ORA agreed with PG&E's proposed changes to its net salvage percentages for the gas distribution function because they result in a decrease in depreciation expense.

TURN presented testimony addressing PG&E's proposed net salvage values, average service lives and survivor curves. With respect to net salvage values, TURN raised concerns regarding: (1) the use of PG&E's SAP accounting system as a basis for making net salvage proposals; (2) PG&E's accounting treatment of "reimbursed retirements" (3) the allocation of replacement costs between installation of new plant and removal of replaced plant; (4) the effect of economies of scale on historic and future costs of removal; (5) the effect of the additional costs incurred for emergency replacements on historic and future costs of removal; (6) the effect of the "investment mix" of historic retirements as compared to the current plant in service on the analyses of service life and net salvage; (7) the occurrence of instances of negative gross salvage in certain years; (8) consideration of future inflation when estimating future net salvage; and (9) the effect of overtime pay and outside contractor costs on the historic and future costs of removal. (Exhibit 439, pp. 14-41.)

TURN recommended adjustments to net salvage for 14 mass property accounts, arguing that PG&E's proposals regarding net salvage values were, in many instances, "much more negative than the industry and almost always more negative than the industry average." (Exhibit 439, p. 5.) TURN also recommended longer average service lives for 5 plant accounts, arguing that PG&E's depreciation study "often ignored the best fitting statistical results of its life analyses or gave weight to insufficiently supported expectations from in-house technical operational personnel to arrive at inappropriate average service lives." (*Id.*)

Relative to PG&E's request, ORA's and TURN's depreciation proposals would decrease PG&E's distribution depreciation expense by $102 million and $172 million, respectively. In Section 3.6 of the Distribution Settlement, the Settling Parties agree to the depreciation parameters resulting from ORA's position on electric, gas, and common plant depreciation.[28]

7.12 Rate Base

PG&E's revenue requirement includes "return on rate base," an amount that compensates PG&E's shareholders for their investment in PG&E's plant and equipment. The calculation of PG&E's rate base has a number of steps, starting with determining the correct beginning plant balance to which capital additions will be added during the test year. The working cash calculation and the capital additions calculation, both components of the rate base calculation, are addressed in other sections of this decision. Ultimately, the rate base must be assigned to UCCs, with residual common plant allocated to all UCCs, including gas and electric distribution and generation UCCs.

PG&E developed its 2003 rate base forecast using 2001 recorded plant as the starting point then adding forecast capital additions for 2002 and 2003. ORA recommended use of 2002, rather than 2001, recorded plant as a starting point. PG&E agreed with ORA's recommendation on rebuttal. (Exhibit 24, p.6-3.)

PG&E and ORA also both advocated the use of O&M labor factors to unbundle residual common plant and reserve, but initially disagreed over which

[28] ORA's depreciation parameters are set forth on pages 5-1 through 5-4 of the Agreement Comparison Exhibit (Attachment B to the Distribution Settlement) and pages D6-1 through D6-4 of Attachment D..

data to use in the calculation. During the hearings, ORA and PG&E agreed to use 2002 recorded adjusted O&M labor factors.

Section 3.7 of the Distribution Settlement adopts recorded 2002 plant as the starting point for calculating 2003 rate base and uses 2002 recorded adjusted O&M labor factors to allocate residual common plant and reserve.

This agreement is reasonable and is fully supported by the record.

7.13 Capital Additions

PG&E's rate base has several components, the largest being plant and depreciation reserve. After establishing the year-end 2002-plant balance, 2003 net weighted average capital additions must be added to determine a 2003 weighted average plant balance. Those capital additions associated with common, general, and intangible plant must then be allocated to all UCCs, including the electric and gas distribution and generation UCCs.

PG&E prepared its forecast of 2003 net weighted average capital additions as follows: First, PG&E prepared a forecast of 2003 capital expenditures by month. This process includes subtracting a forecast of certain customer contributions that offset PG&E's capital expenditures (including joint pole receipts). Second, PG&E converted capital expenditures to capital additions. For large projects, this conversion was based on expected dates of operation. For smaller, on-going expenditures, expenditures may be converted to additions as spent. Third, PG&E converted gross capital additions to net additions (net of retirements) based primarily on ratios developed through analysis of historic information. Finally, PG&E used the monthly forecast of net capital additions to calculate a weighted average for the year.

ORA analyzed PG&E's forecast step-by-step, making specific recommendations on many aspects of the forecasting process, then recommending its own forecast. During the course of rebuttal and hearings, PG&E and ORA came to agreement on many of the issues raised by ORA.

By the time the Comparison Exhibit was filed on August 8, 2003, the scope of disagreement had narrowed to only a few issues: (1) PG&E's and ORA's differing forecasts of electric and gas distribution and common capital expenditures; (2) PG&E's and ORA's different methods for transferring recorded 2002 Construction Work in Progress (CWIP) to electric and gas distribution and common plant in service in 2003; (3) PG&E's and ORA's different operative dates for various distribution and common projects; and (4) PG&E's and ORA's different methods of forecasting weighted average gas distribution plant.

Aglet also raised an issue regarding the forecast of joint pole receipts (representing the joint pole owner's share of capital projects). TURN joined Aglet in the recommendation that PG&E's forecast of joint pole receipts should be $21 million, an increase of $4.1 million over PG&E's initial forecast.

In the Distribution Settlement, the parties agreed that net weighted average capital additions for 2003 ($2003) will be $292 million for the electric distribution UCCs and $89.2 million for the gas distribution UCCs. The Settling Parties further agreed that the above net capital additions reflect a 2003 forecast for joint pole receipts (representing the joint pole owner's share of capital projects) of $21 million.

The net weighted average capital additions for 2003 adopted in the settlement assume the incorporation of higher capitalization rates for A&G and reflect an allocation of net weighted average additions for common, general and intangible plant of $17.4 million for the electric distribution UCCs, $10.9 million for the gas distribution UCCs, and $7.765 million for the electric generation UCCs.

PG&E forecast 2003 net weighted average capital additions for the electric distribution UCCs at $351.335 million, compared to ORA's forecast of $223.738 million. The Settling Parties compromised on this issue, resulting in net weighted capital additions of $292 million.

PG&E forecasts 2003 net weighted average capital additions for the gas distribution UCCs at $107.767 million, compared to ORA's forecast of $72.786 million. The Settling Parties compromised and agreed to $89.2 million for gas distribution. Embedded in these forecasts were allocations of common, general, and intangible plant to the electric distribution UCCs of $17.392 million for PG&E and ($0.386) million for ORA, and to the gas distribution UCCs of $10.889 million for PG&E and ($1.326) million for ORA.

PG&E and ORA reached agreement on the 2003 net weighted average capital additions for generation assets in the Generation Settlement. However, the Comparison Exhibit reflects the unresolved issues concerning the amount and allocation of common, general, and intangible plant to the generation UCC. PG&E's forecast allocation of 2003 net weighted average capital additions for common, general, and intangible plant to the generation UCCs was $7.765 million, compared to ORA's forecast of $6.042 million.[29]

The Distribution Settlement adopts PG&E's forecast and allocation of common, general, and intangible plant and compromises between PG&E's and ORA's positions on electric and gas distribution plant. In addition, the perspective offered by Aglet and TURN on joint pole receipts was recognized in the development of the electric distribution plant forecast. Based on the record developed in this GRC, the Settling Parties were able to agree to a reasonable compromise that establishes 2003 net weighted average capital additions for the electric and gas distribution and generation UCCs, as well as the allocation of common, general, and intangible plant to the electric and gas distribution and generation UCCs.

7.14 Working Cash

The working cash forecast consists of two elements: (1) working funds needed for PG&E's daily operations; and (2) funds needed to cover operating expenses paid before PG&E receives customer revenues. These funds are included in PG&E's rate base and therefore affect the computation of the amount of operating income.

In their litigation positions, both ORA and TURN recommended a significant further reduction of approximately $99 million combined electric and gas distribution working cash based on PG&E's accrued vacation liability account. TURN also recommended that interest-bearing customer deposits should be an offset to rate base, resulting in a further reduction of $116 million.[30] In addition, TURN suggested two relatively small adjustments reducing accounts receivable ($3.406 million) and accounts and tax collections payable ($1.678 million).

In Section 3.9 of the Distribution Settlement, the Settling Parties agree to reduce working cash by $63 million electric and $37 million gas ($2003) relative to the amount in PG&E's Comparison Exhibit, representing a compromise from

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[29] Ex. 100, p. 2-30.

[30] Ex. 405, p. 26.

the litigation positions of each of the Settling Parties. In the Comparison Exhibit, PG&E forecast working cash of $74.626 million and $41.575 million ($2003) for electric and gas distribution, respectively. ORA forecasts working cash of $6.200 million and $2.864 million ($2003) for electric and gas distribution, respectively.

7.15 Taxes

Although a broad range of tax issues was addressed in PG&E's testimony, and in the testimony of ORA and TURN, only a small number of issues remained unresolved by the completion of rebuttal and filing of the Comparison Exhibit. The Distribution Settlement (Section 3.10) adopts the following agreements:

1. Settling Parties agree to use PG&E's method for calculating vehicle clearing depreciation for purposes of determining income taxes,
2. Settling Parties agree to recognize the current year deduction for capitalized A&G overheads for the calculation of test year income taxes; and
3. Settling Parties agree that the effect of the 50 % bonus depreciation, a change in the tax code, will not be recognized for the calculation of 2003 income taxes.

In addition to the tax issues addressed by the Distribution Settlement, there were a number of uncontested tax issues presented in PG&E's testimony, as well as a number of tax issues that were initially contested but were resolved by the time the Comparison Exhibit was filed. These issues are not specifically addressed in the Distribution Settlement, but they are included in the underlying assumptions used to calculate the revenue requirements associated with the Settlement.[31]

Only two tax issues remained contested by ORA: PG&E's income tax adjustments for certain past capitalized A&G overhead costs, and whether an increase in "Bonus Depreciation" as a result of legislation enacted earlier this year (2003) should be reflected in the test year revenue requirement computation.

Before 2000, PG&E's practice was to capitalize certain A&G costs in the same amount for both tax and book purposes. Beginning in 2000, PG&E took advantage of a Treasury Regulation that permits a taxpayer, under certain circumstances, to take an immediate tax deduction rather than capitalizing the A&G costs.[32] ORA took the position that PG&E's tax forecast "does not reflect any deduction for the A&G overheads that can be deducted under the de minimis rule," and therefore PG&E's tax expense is overstated.

In 2003, PG&E's tax return will reflect deductions pertaining to: (1) retroactive application of the de minimis rule to the period 1989 to 1999; and

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[31] In addition to income and property taxes, PG&E presented testimony and forecasts of other taxes PG&E must pay. These taxes include payroll, business license, federal highway use and timber yield taxes. PG&E's testimony and forecasts of such taxes are uncontested. (Ex. 304, p. 13-20.) As to income and property taxes, PG&E's treatment of: (1) software expenditures; (2) cost of removal; (3) repair allowance; (4) investment tax credits; and (5) the federal tax deduction of prior year California Corporate Franchise Tax were all undisputed. (Ex. 24, p. 1-1.) Only ORA and TURN submitted testimony on tax-related issues. ORA and TURN both disputed PG&E's proposed three-year amortization period of the Financial Accounting Standards No. 109 Tax Regulatory Asset. TURN proposed balancing account treatment for property taxes for Diablo Canyon Nuclear Power Plant. These issues were resolved in the Generation Settlement.

[32] Ex. 24, pp. 1-5 to 1-6.

(2) and current application of the de minimis rule to certain, current A&G overhead costs. PG&E agreed with ORA that this annual "going forward" deduction for current A&G overhead costs should be reflected in the revenue requirement calculation.[33] PG&E's position in the Comparison Exhibit reflects the immediate deduction of these A&G costs for tax purposes. The Distribution Settlement provides that the deduction pertaining to the retroactive period should not be reflected in the revenue requirement calculation for 2003.

The Distribution Settlement represents a reasonable compromise of the positions held by the parties and is fully supported by the record developed in this proceeding. The retroactive application of the de minimis rule is the result of an Internal Revenue Service (IRS)-approved change in accounting methodology that PG&E instituted in 2000. The IRS permitted PG&E to implement this change not only for the future, but also to realize a deduction for the years 1989 through 1999. By law, PG&E was required to take this deduction over a four-year period beginning in 2000 through 2003. The final deduction installment of $11.32 million will occur during 2003; thereafter there will be no further "additional deductions" related to the 1989-1999 period. The $11.32 million relates to a period before the test year and is not representative of future conditions and therefore, by agreement of the Settling Parties, will not be included in the test year revenue requirement calculation.

The bonus depreciation issue was raised during ORA's cross-examination of PG&E's tax witness, and concerns a new provision of the tax code that became effective in May 2003. (TR 1439:18-27.) Therefore, the Settling Parties' agreement

[33] Ex. 24, p. 1-7.

not to incorporate this change in the tax code in the 2003 revenue requirement calculation is consistent with the intent of the ACR issued February 13, 2003, to prohibit the use of 2003 recorded data.

7.16 O & M Labor Factors

The 1999 GRC Decision adopted the use of O&M labor factors to unbundle residual common costs that cannot be directly assigned based on cost causation. In this 2003 GRC, PG&E and ORA agreed that the same approach should be used, but did not agree on the specific O&M labor factors.

Initially, PG&E proposed using 2003 forecast O&M labor factors in unbundling. ORA disagreed with PG&E's proposal, suggesting that the Commission adopt O&M labor factors used in PG&E's electric transmission rate application made before the FERC on January 13, 2003 (PG&E's Transmission Owner (TO) 6 filing, ER03-409-000). (Exhibit 306, p. 1-25 to 1-26.)

In rebuttal testimony, PG&E proposed using 2002 recorded adjusted O&M labor factors. (Exhibit 22, p.4-2.) ORA agreed with PG&E's proposal during the hearings. (TR 3150: 3-8.)

Section 4.2 of the Distribution Settlement provides that 2002 recorded adjusted data shall be used to calculate the O&M labor factors used to unbundle common costs to UCCs in the revenue requirement calculation.

7.17 Other Operating Revenues

Other Operating Revenues (OORs) are revenues from transactions not directly associated with the transportation or sale of gas and electricity. OORs are estimated separately and subtracted from the revenue requirement in the rate design process because OORs reduce the amounts that must be collected from customers in rates.

PG&E forecast electric and gas distribution-related OORs of $65.004 million and $15.992 million, respectively,

In Section 4.3 of the Agreement, the Settling Parties agree that CPUC-jurisdictional distribution OORs shall be $67.3 million electric and $16.3 million gas ($2003).

Initially, ORA and TURN both questioned PG&E's OOR forecast. ORA forecasted OOR of $68.879 million electric and $16.642 million gas. ORA's recommended adjustments to PG&E's forecast were based on its position with regard to insufficient funds (NSF) fees.

ORA also took issue with PG&E's OOR forecast for three accounts: 454 (Rent From Electric Property), 488 (Gas Miscellaneous Service Revenues), and 493 (Rent From Gas Properties). The revenues recorded within these accounts fluctuate from year to year, as do all of the OOR accounts. Given these fluctuations, PG&E has historically based its OOR estimates on the last recorded year. Based on the history of fluctuation in the accounts, ORA forecasted that the revenues should be increased by 11% in the case of Accounts 454 and 493, and 2% for Account 488.

In errata, TURN withdrew its recommendation to increase OORs by $2.1 million to account for higher joint pole revenues; TURN now supports Aglet's recommendation on the issue of joint pole receipts.

The Distribution Settlement reflects a compromise of the positions of the parties. It recalculates the OOR forecast based on the agreement of the parties on the NSF fee, and represents a compromise of PG&E's and ORA's positions on forecasts of rent from properties and miscellaneous service revenues, items that fluctuate considerably from year to year. This compromise result is fully supported by the record created on this issue.

7.18 New Customer Connections and E-Net Costs

PG&E requested that the Commission adopt two-way balancing accounts for: (1) capital expenditures related to new customer connections in MWC 16 (Electric Distribution Customer Connects) and MWC 29 (Gas Distribution Customer Connects), and (2) the costs related to PG&E's processing of customers' requests to connect self-generation equipment to PG&E's distribution system (also known as E-Net applications) included in MWC EW on the basis that these items are difficult to forecast and fluctuations expenditures represent risk to PG&E. ORA recommended against adoption of these balancing accounts because ORA finds the variance between PG&E's and ORA's forecasts to be minimal, the Commission has a track record of adopting expense estimates knowing that actual spending will likely differ, and because balancing account treatment represents a move to micromanaging PG&E's business.

The Distribution Settlement adopts ORA's position regarding balancing accounts for new customer connection and E-Net costs.

7.19 Insufficient Funds Fee

PG&E currently charges a $6.00 fee to those customers whose checks are returned because they have insufficient funds to cover the checks. This charge is known as an NSF (Non-Sufficient Fund) fee. PG&E's $6.00 NSF fee for returned checks was set in 1995. In this 2003 GRC, PG&E proposed to increase its NSF fee to $10.00 based on an analysis demonstrating that PG&E's NSF processing costs are $10.54. (Exhibit 3, p.9-3, Table 9-1.)

ORA and TURN both offered testimony on this issue. Neither party challenged PG&E's cost analysis, but each party used a different rationale to recommend NSF fees. ORA proposed increasing the NSF fee by only $2.00 to "mitigate the impact on customers who pay the NSF fee." ORA stated that its proposal for an $8.00 NSF fee was not based on PG&E's actual costs of dealing with bounced checks. (TR 3422:16.) Rather, ORA's proposal was motivated by concern for low-income customers who bounce checks.

TURN proposed a variable fee derived from a $6.50 base charge plus one % of the amount of the returned check. PG&E presented an analysis showing that TURN's proposal could result in charging check bouncers more than PG&E's actual costs. PG&E also expressed concern that a variable NSF fee might confuse customers, and that a variable fee would require substantial programming changes to the CIS and result in additional administrative costs.

The Settling Parties agree in Section 4.5 that PG&E should increase the NSF fee for returned checks from the current $6.00 to $8.00. The agreement to increase PG&E's NSF fee to $8.00 represents a reasonable compromise that acknowledges PG&E's cost study demonstrating that PG&E's costs of handling bounced checks are higher than the current $6.00 fee, while also acknowledging the concern that the new fee not present an undue hardship for low-income customers.

7.20 Public Utilities Code Section 739.10

The ACR directed PG&E to submit testimony concerning how it intends to comply with Public Utilities Code Section 739.10 (added by Stats. 2001, 1st Ex. Session, Ch.8, Sec. 10). Section 739.10 provides that "[t]he Commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or undercollections of the electrical corporations."

NRDC agreed with PG&E that to comply with Section 739.10, the Commission should establish a means by which to "track actual revenues compared to PG&E's Commission-approved revenue requirements, and make periodic true-ups to adjust for over- and undercollections." (Exhibit 750, p. 1.) Although NRDC would prefer one revenue adjustment mechanism rather than the two proposed by PG&E, as part of the Distribution Settlement, NRDC is willing to accept PG&E's proposal to utilize DRAM and UGBA to comply with Section 739.10.

Section 4.6 of the Distribution Settlement provides that PG&E will comply with Section 739.10 by implementing the Distribution Revenue Adjustment Mechanism (DRAM) and Utility Generation Balancing Account (UGBA)[34] as revenue adjustment mechanisms effective January 1, 2004, to ensure that PG&E recovers its authorized electric distribution and electric generation revenue requirements regardless of the level of sales.

7.21 Recovery of Expenses Associated With the 20/20 Program

The ACR provided that the issue of recovery of costs associated with the delay in implementing PG&E's new Customer Information System (CIS) required to implement the 2002 "20/20" program is within the scope of the GRC and directed parties to address both the reasonableness of the costs and whether ratepayers or the DWR are to pay these costs.

Section 4.7 of the Settlement Agreement reads:

> "The Settling Parties agree to allow recovery of the revenue requirement associated with $7.3 million in 2002 expenses incurred to implement the 20-20 program. PG&E will initially recover this revenue requirement from ratepayers by a debit entry to the Distribution Revenue Adjustment Mechanism (DRAM). The Settling Parties agree that DWR is ultimately responsible for these costs. PG&E will bill DWR the same amount debited to DRAM, and credit funds received from DWR to DRAM."

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[34] UGBA was adopted by the Commission in D. 02-04-016, April 4, 2002. When adopted, UGBA would have balanced revenue received against some forecast and some actual costs. Once this GRC is decided, UGBA will balance revenue received against forecast costs as adopted in this GRC. Effective January 1, 2004, per the Agreement, Section 4.6, UGBA will be separated from the TRA and will perform the functions of a revenue adjustment mechanism in compliance with Section 739.10.

DWR submitted a memorandum on October 1, 2003, requesting that the Commission reject the portion of the Distribution Settlement concerning recovery of costs related to implementation of the 2002 customer rebate program known as the California 20/20 Rebate Program. DWR states that the Distribution Settlement is not consistent with the terms and conditions for reimbursement of 20/20 implementation costs established by DWR and accepted by the Commission in Resolution E-3770.

DWR explains that although it agreed to reimburse the utilities for "implementation and administration fees to the utilities to cover their reasonable costs of establishing and maintaining the procedures, systems, and mechanisms that are necessary to implement the 2002 California 20/20 Rebate Program," there is nothing in the record that establishes that these costs meet the requirements for reimbursement. DWR claims that PG&E has previously presented the costs it seeks to recover to DWR and requested payment and that DWR has already found these costs unreasonable and refused PG&E's request for reimbursement. DWR maintains that the practical effect of requiring DWR to reimburse PG&E for the costs associated with the implementation of PG&E's new CIS system would be to shift portions of the costs onto SCE's and SDG&E's ratepayers, since any reimbursement would be funded through DWR's Revenue Requirement determinations.

The Settling Parties respond that the record clearly establishes that the costs at issue should be addressed in this proceeding, citing the February 13, 2003, ACR. The Settling Parties argue that Exhibit 82 of its testimony provides clear and convincing evidence regarding how the 20/20 program caused significant delays in implementing PG&E's CIS. The Settling Parties maintain that the Commission should approve the Settlement, with the understanding that any further proceedings regarding the question of DWR's responsibility to reimburse PG&E for the $7.3 million will affect the provision of Section 4.7 of the Settlement, calling for crediting of amounts recovered from DWR.[35]

7.21.1 Discussion

The ACR directed parties to review PG&E's testimony served with A.02-09-005 and A.02-11-017 and address both reasonableness and cost responsibility in their testimony in this proceeding. As directed, the Settling Parties have considered the costs in question as part of PG&E's TY 2003 forecast. As stated above, Section 4.7 of the Settlement provides that the cost associated with the delay in implementing the new CIS is $7.3 million. The Settling Parties further agreed that DWR should be responsible for these costs. However, the Settlement provides for the possibility that DWR may not reimburse PG&E by allowing PG&E to make a debit entry in the DRAM for $7.3 million, to be followed by a credit to the DRAM if and when PG&E receives reimbursement from DWR. In the event that DWR does not reimburse PG&E, PG&E ratepayers would bear the $7.3 million in cost associated with the delay in implementing the CIS.

The Settling Parties have agreed that the cost associated with the delay in implementing the new CIS is $7.3 million. The practical effect of the Settlement

[35] Independent of the Settling Parties, PG&E notes that DWR did not file testimony in response to PG&E's testimony in A.02-09-005. PG&E states that DWR's assertion that "PG&E has previously presented the costs it seeks to recover through its General Rate Case to DWR and requested payment," is incorrect in that PG&E has never presented

Footnote continued on next page

is that PG&E's ratepayers will bear the responsibility for this $7.3 million, either directly or indirectly. The terms and conditions under which DWR will reimburse the utilities for the utilities' reasonable costs for implementing and administering the 20/20 program were established in Commission Resolution E-3770 as follows:

> "The Department will pay implementation and administration fees to the utilities to cover their reasonable costs of establishing and maintaining the procedures, systems, and mechanisms that are necessary to implement the California 20/20 Rebate Program. Utilities shall invoice the Department for payment of the implementation and administration fees. Invoices shall include reasonable documentation of the costs incurred. Utilities will exercise best efforts to track and keep costs within the amounts billed to the Department last year for the 2001 20/20 program. The Department must approve the invoiced amounts. The Department cannot unreasonably withhold approval." (Res. E-3770, dated June 6, 2002 Appendix 2, p. 2.)

We find that approval of the Settlement is reasonable because it resolves the following critical questions in a fair manner: (1) the appropriate cost associated with the delay, and (2) the ratemaking mechanism PG&E will use to recovery the costs from ratepayers. Whether or not the $7.3 million in question meets DWR's requirements for reimbursement is a question that only DWR has the authority to determine.

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such costs to DWR and PG&E has never received notice from DWR that such costs were rejected as unreasonable.

7.22 Customer Information System (CIS) Capital

PG&E presented evidence in this GRC forecasting expense and capital costs for a number of Information Technology (IT) projects, including the Enterprise Application Integration (EAI) Project,/ the Utility Operations Customer Care Project including maintenance of the mainframe computer, the CorDaptix CIS, CIS operations and maintenance, and Other IT Costs. The EAI and Other IT Costs requested above were neither addressed nor contested by any party in this proceeding.

The CIS is an information technology system that supports PG&E's customer billing, payment tracking, and bill settlement.[36] In this GRC, PG&E requested $176 million in capital expenditures for its CIS project, and $49 million[37] in associated O&M expenses.

ORA did not contest PG&E's capital expenditure request for the CIS project but did recommend an approximate $6 million adjustment to normalize the CIS O&M expenses.

TURN recommended that the Commission disallow $85.8 million (later revised to $73.5 million in errata) in capital expenditures. TURN also

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[36] PG&E's CIS processes and maintains customer account information, meter read data, bill calculation and invoice information, bill history, service order data, real-time outage information, payment information, credit history and revenue reporting information. Call centers, local area offices, field operations, credit and collections, billing, payment processing, and the emergency operations center all use CIS.

[37] This amount is for O&M (FERC Account 903-Customer Records and Collection Expense) only; PG&E has also included approximately $5 million in other expense accounts (FERC Account 408 – Payroll taxes and FERC Account 926 – Pensions and Benefits).

recommended that O&M expenses on the CIS system be held to 20% of the capital cost. Accordingly, they recommended a disallowance of $13 million in O&M for the CIS system.

The Distribution Settlement resolves the CIS O&M issues by adjusting PG&E's initial expense forecasts to account for ORA's recommendation regarding the timing of the expenses. According to the Settlement Agreement, this revised O&M expense estimate fully resolves ORA's and TURN's issues regarding CIS expenses.

To resolve TURN's recommended capital disallowance, the Settling Parties agreed that PG&E would include in its Results of Operations a $7 million credit against the revenue requirement through 2006. PG&E will retain the capital in its ratebase and continue depreciation using the applicable deprecation schedule for CIS.

7.22.1 Discussion

D.00-02-046 presents a full discussion of CIS funding to that time as follows:

> "PG&E installed its CIS in 1964, and has made significant modifications to it in the intervening years. PG&E refers to this system, as currently being modified, as its Legacy CIS (LCIS)." "in the last decade, PG&E has made several attempts, since abandoned, to accomplish major upgrades to its CIS. In its 1990 GRC, PG&E received funding for its 1989-1993 CIS Rewrite project, a phased rewrite of the CIS. In 1993, after spending millions of dollars, PG&E abandoned this project. In 1994 and 1995, PG&E undertook development of a non-core CIS (nCIS) to meet the needs of PG&E's 200 largest customers using a client server technology. PG&E terminated the nCIS project in 1995, after completing the system analysis and design programming phases and beginning system testing. More recently, after issuing a Request for Proposal in August 1995, PG&E contracted with IBM to purchase and modify an

> off-the-shelf system in March 1996. PG&E spent 44.2 million on the IBM Integrity project in 1996 ad 1997, $34.2 million in 1996 alone. The IBM Integrity project was then terminated in 1997. Since 1997, PG&E has begun conversion of its CIS to a new technology called Genesis. The LCIS is currently operating in parallel with Genesis. PG&E anticipates completing the Genesis project in 2001, at which time the LCIS will be retired." (*Mimeo.*, p. 388-389.)

In its TY 1999 GRC, PG&E reduced its CIS request for a base CIS from $146.7 million to $84.6 million to remove industry restructuring costs. The Commission concluded that the cost for a base CIS would range from a low of $30 to $50 million to a high of $88 to $14 million. The Commission concluded that the PG&E's requested $84.6 million fell within that range, but reduced PG&E's request by $10.8 million to reflect that certain costs associated with the IBM Integrity project that were not used and useful, resulting in an authorization of $73.8 million for a base CIS.

In this case, TURN argues that of the $176.3 million at issue, ratepayers have already funded $73.8 million in the 1999 GRC. Based on the record developed in this case, and TURN's showing that ratepayers have already funded a substantial portion of the total $176.3 million in the 1999 GRC, we would have been inclined to consider TURN's recommended disallowance for capital expenditures. However, we find the Distribution Settlement's compromise of a $7 million revenue requirement credit reasonable because it yields a dollar amount close to TURN's recommendation. If TURN's $73.5 million disallowance had been made to capital expenditures, it would have reduced the 2003 revenue requirement by approximately $7.6 million.

We agree with the Settling Parties that this outcome is reasonable, and fully supported by the record in this GRC, particularly as part of the broader Settlement. As set forth in Section 4.8 of the Settlement, PG&E shall include in its results of operations a $7 million credit against the revenue requirement (which will be allocated among PG&E's functions using the allocation method for the CIS system). The $7 million adjustment will extend through 2006 under the attrition method in the Settlement. PG&E will retain the capital in its rate base and continue depreciation using the applicable depreciation schedule for CIS. In the 2007 GRC, PG&E will include the remaining undepreciated balance of this capital in rate base.

7.23 Idle Facilities

Aglet and MID raised issues regarding PG&E's treatment of idle facilities. Aglet's issue concerned the accounting transactions associated with the life cycle of assets. This issue is resolved in Section 4.9 of the Agreement, which provides that PG&E will include in its next GRC a showing on the plant and depreciation accounting transactions associated with the life cycle of distribution assets and the requirements of the Uniform System of Accounts and other applicable accounting standards. This showing shall include, at a minimum, a description of PG&E's current practices and the basis for those practices.

MID raised a concern about the lack of standards for removal of idle facilities. This issue is resolved in Section 4.10 and Appendix A of the Agreement, which provides that within the joint MID and PG&E service area described in Public Utilities Code Section 9610 (b)(1), PG&E will remove those idle facilities located on private property that PG&E determines do not have any foreseeable use. Appendix A to the Distribution Settlement sets forth the terms under which that determination will be made.

7.24 Integrated Resource Planning

In response to the February 13, 2003 ACR, PG&E filed testimony regarding costs related to Integrated Resource Planning (IRP). PG&E requested that the Commission authorize an additional $11 million in O&M and A&G expense and capital expenditures to support IRP. PG&E also requested an additional $22.1 million of O&M expense to perform the activities associated with procuring electricity, arguing that these activities have been expanded in scope and complexity by recent, and still evolving, Commission decisions on electric procurement issues.

ORA recommended that the Commission reject PG&E's request for an additional $11 million for expenses and capital expenditures for IRP activities as well as PG&E's $22.1 million forecast associated with Electric Transaction Administration. In addition, Aglet and NRDC presented testimony discussing the overarching policy issues associated with integrated resource planning.

Section 4.11 of the Distribution Settlement recognizes that the ACR directed PG&E to identify costs of staffing associated with an assumption that PG&E will "remain a vertically integrated utility responsible for procuring and providing resources to its customers…."and states that "The Settling Parties understand that the Commission is considering integrated resource and procurement issues in R.01-10-024 and that the Commission will further define PG&E's role in this area which may affect costs. The Settling Parties reserve their rights to address such issues in other proceedings, as the role of utilities in this area is further developed by the Commission."

The Settling Parties note that no specific amounts are set forth in the Agreement for these IRP or expanded Electric Transaction Administration activities and that PG&E understands that it will meet its current responsibilities within the funds set forth in the Settlement.

7.25 Service Guarantees Under the Quality Assurance Program and Customer Service Issues

In D.00-02-046, the Commission directed PG&E to establish a Quality Assurance Program (QAP). In this proceeding, ORA recommended a number of changes to PG&E's existing QAP. ORA also recommended changes to PG&E's "Safety Net Program" during the Storm Response/Reliability phase of this GRC.

In addition, ORA recommended that PG&E: (1) follow up on recommendations contained in a "Network Study" prepared at PG&E's request concerning possible efficiency improvements PG&E might make in its local office and pay station operations; (2) process payments made at its drop boxes by 2 00 p.m. on the same day that payments are deposited; (3) survey customers who patronize PG&E's local offices and the pay stations PG&E maintains under contract to determine customer satisfaction; (4) explore enhancing retention efforts for customer service representatives; (5) investigate whether to implement technology improvements and/or process changes to enhance communications between call center and field employees; (6) investigate whether PG&E's translation service is meeting the needs of the various Asian/Pacific Islander communities; and (7) improve its website functionality and file an annual report with the Commission and ORA for three years, which describes and evaluates efforts to improve the website.

TURN suggested that PG&E explore alternatives for securing lower fees for customers who choose to pay their PG&E bills via debit or credit cards when its contract with its current vendor expires. (Exhibit 403, p. 26.)

The Settling Parties have resolved these issues in Appendix B to the Agreement, which sets forth all of the Customer Service-related agreements. These agreements, taken together, improve the Quality Assurance Program and address all of the other customer-related issues and proposals noted above. In addition, this Appendix resolves issues with regard to PG&E's "Safety Net

Program" that were raised in the Storm and Reliability Phase of this GRC and previously submitted in briefs.[38]

8. Terms of the Generation Settlement

PG&E initially requested a 2003 generation revenue requirement of $1.022 billion. ORA, TURN, Aglet, and CCSF each recommended reductions to PG&E's request. The Generation Settlement resolves all contested issues raised in connection with PG&E's forecast 2003 electric generation revenue requirement and provides for a TY 2003 generation revenue requirement of $912 million,[39] as follows:

Table 5
Comparison of Generation Settlement to PG&E and ORA Litigation Positions (Millions of Dollars)

Unbundled Cost Category	PG&E Application	ORA Position	Generation Settlement	Reduction from PG&E's Application
Fossil	118	95	94	24
Hydro	345	302	323	22
Diablo Canyon	545	468	535	10
Purchased Power	14	9	3	11

[38] Opening Brief of ORA on Storm and Reliability Issues, July 21, 2003, pp. 2-3; Opening Brief of PG&E in the Storm / Reliability Performance Phase of the 2003 GRC, July 21, 2003, pp. 28-31.

[39] The Generation Settlement filed on July 31, 2003 indicates that the Generation Revenue Requirement for TY 2003 is $955 million, subject to future adjustment based on the Commission's resolution of the contested A&G and tax issues. The Distribution Settlement resolves the remaining A&G and tax issues, resulting in TY 2003 generation revenue requirement of $912 million.

Total	1,022	875	955	67

The components of the reduction from PG&E's application are the result of the Settling Parties compromise on several issues including:

8.1 Return on Regulatory Assets

PG&E requested that the unamortized balance of the WAPA, Helms and Loss on Sale of Power Plants regulatory assets be included in rate base and earn a return. ORA and TURN opposed PG&E's request. The settlement removes the return on these assets from the revenue requirements without prejudice and provides that the issue as to whether a return on these assets is appropriate will be addressed in the end-of-freeze phase of A.00-11-056, resulting in a $10 million reduction to PG&E's TY 2003 revenue requirement.

8.2 Amortization of the Statement of Financial Accounting Standard No. 109 (FAS 109) Regulatory Asset

PG&E proposed to amortize the outstanding balance of the Statement of Financial Accounting Standard No. 109 (FAS 109) flow-through regulatory asset over a three-year period beginning in 2003. ORA and TURN recommended that PG&E be required to amortize the FAS 109 flow-through regulatory asset over 20 years based on the remaining lives of the plant assets giving rise to the tax asset.

PG&E responded that in D.97-11-074 and D.02-04-016, the URG decision, the Commission recognized that the FAS 109 asset should be amortized over a period shorter than 20 years.

The Generation Settlement provides that the FAS 109 flow-through regulatory asset should be amortized over the remainder of the 10-year schedule adopted in D.02-04-016 (*i.e.*, 9-year amortization beginning in 2003).

8.3 Diablo Canyon Depreciation

PG&E proposed to shorten the depreciable life of certain major plant components at Diablo Canyon to 15.8 years to reflect their anticipated replacement prior to the end of the operating life of the plant. The remainder of the functional plant equipment would be depreciated over 19 years. ORA and TURN recommended depreciating all of the Diablo Canyon plant over 21 years.

The Settling Parties agree that the functional plant at Diablo Canyon will be depreciated over 19 years, while common plant items such as fleet and computers would be depreciated in accordance with the depreciation schedule proposed for all such assets.

8.4 Diablo Canyon O&M Expense

PG&E forecast TY 2003 Diablo Canyon O&M expense using 2001 recorded costs as a base. ORA recommended using a 3-year average of Diablo Canyon recorded costs to forecast 2003 O&M expense, resulting in an $11 million reduction to PG&E's forecast Diablo Canyon O&M expense. ORA also recommended adjusting the 2003 forecast by an additional $2.3 million, reflecting ORA's lower estimate for the reactor vessel chemical cleaning project. As part of the Generation Settlement, the Settling Parties agreed to adopt PG&E's forecast.

8.5 Additional Security Costs at Diablo Canyon

The Generation Settlement authorizes an additional $3 million in revenue requirement ($2003) for additional security costs at Diablo Canyon to cover the expected cost increase associated with the Nuclear Regulatory Commission's April 29, 2003 orders increasing security requirements at nuclear power plants. Although the consideration of actual 2003 costs is inconsistent with prohibition of the use of actual 2003 data set forth in the ACR issued February 13, 2003, the Settling Parties support inclusion of these costs.

8.6 Post Test Year Capital Applications

Aglet recommended that we require PG&E to file a separate application supporting its requested rate recovery for Diablo Canyon refueling outages and the LP Turbine Rotor Replacement project. The Generation Settlement provides that the base revenue requirement includes one refueling outage. If PG&E forecasts a second outage in any one year, the authorized revenue requirement would be increased to reflect a fixed revenue requirement of $32 million ($2003) per refueling outage. PG&E agreed that the Low Pressure Turbine Rotor Replacement project would be reviewed in its next GRC.

8.7 Fuel Oil Inventories

ORA recommended that the Commission require PG&E to recover the return on fuel oil inventories through the Energy Resources Recovery Account. The Generation Settlement adopts PG&E's request to include recovery of the carrying costs on the fuel oil inventories in the 2003 GRC.

9. Conclusion

The principal public interest in this proceeding is the delivery of safe, reliable, utility service at just and reasonable rates. After careful review and subject to the modification discussed in Section 7.2 above, we are convinced that the Settlements balance the various interests at stake, resulting in a fair and reasonable TY 2003 revenue requirement, such that we can find PG&E's rates to be just and reasonable. Pursuant to Rule 51.1(e) we reach this conclusion only after finding that the Settlements, taken together, are reasonable in light of the whole record, consistent with the law, and in the public interest.

9.1 Reasonable in Light of the Whole Record

We find that the Settlements are reasonable in light of the whole record for two reasons. First, while the Settlements are not all partly settlements, they are supported by all parties taking positions on PG&E's TY 2003 revenue requirement request. ORA, whose charge is to represent ratepayer interests, was an active participant in the proceeding and supports the Settlements. ORA filed complete, detailed testimony consisting of an account–by-account review of PG&E's TY 2003 revenue requirement forecast.

TURN and Aglet also represent ratepayer interests and were active participants in the proceeding. TURN and Aglet each offered several recommendations, including reductions to PG&E's forecasts for CIS, A&G expenses, Distribution O&M expenses, Customer Accounts and Services, joint pole receipts, meter reading expenses, uncollectibles, and attrition relief. MID, NRDC, and CCSF each took issue with specific elements of PG&E's TY 2003 forecast and proposed alternative forecasts for these issues.

Only one party opposes any portion of the Settlements, and that party, DWR, takes issue with one aspect of the Distribution Settlement, but does not oppose the remaining elements.

The parties' negotiations were informed by a thorough record consisting of over 200 exhibits and 36 days of evidentiary hearings. Consequently, the Settling Parties had ample opportunity to test the positions of opposing parties through discovery and cross-examination. In addition, the positions presented generally represented strongly held, well-supported opinions of experienced witnesses who are familiar with this Commission's processes. When parties with opposing interests agree to a settlement, it may be one indication of the reasonableness of the settlement.

Second, the revenue requirements adopted by the Settlement are within the range of positions taken by the parties. In supporting the Settlements, PG&E is foregoing $304 million compared to its TY 2003 forecast as presented in the

Comparison Exhibit, and ORA is agreeing to an increase of $84 million compared to its final litigation position. We find that the revenue requirements contemplated by the Settlements are justified by the parties' showing and are in the interest of PG&E's ratepayers and the public.

9.2 Consistent with the Law

Although the Settling Parties have not identified any statutory provision or prior Commission decision that would be contravened by the Settlements, as discussed in Section 7.2, above, we find that the provision of the Settlements allowing for a "minimum" attrition adjustment is inconsistent with our attrition policy and incompatible with the public interest. We have modified the Settlements to eliminate the minimum attrition adjustment.

We are not aware of any other policy, rule or order that would be contravened by the Settlements. Although PG&E requested that the Commission reconsider several of the findings adopted in D.00-02-046 in its showing, the Settlements adopt a "high level" agreement, and do not attempt to modify the Commission's findings and policies adopted in D.00-02-046. As modified to remove the minimum attrition adjustment and with the understanding that the Settlements should be construed as leaving intact all policy decisions adopted in D.00-02-046, we find that the Settlements are consistent with the law and Commission precedent.

9.3 In the Public Interest

Finally, we find that the Settlements are in the public interest. Like many settlements, they are the result of compromises to accommodate and balance the interests of all the parties and the public. We find that Settling Parties have compromised their litigation positions and have arrived at a reasonable result in light of the extensive record.

The Settlements would adopt total amounts for general categories rather than adopting a detailed forecast for each specific account. The Settling Parties maintain that this high level agreement does not imply any specific resolution of issues at a detailed level, with the exception of those issues specifically discussed in the Settlements. In the interest of not altering the Settlements, we are willing to take a step back and approve forecasts for general categories, but in doing so, we must acknowledge that there are downstream consequences associated with adopting this type of "black box" approach. For example, in PG&E's next GRC, parties will not be able to ascertain the specific amounts adopted for certain accounts, or compare recorded amounts to the corresponding "adopted" forecast with the same degree of precision we typically expect. We do not view this as an insurmountable problem, given the fact that under forecast test year ratemaking a utility is generally neither obligated to spend the authorized amount nor limited to spending only the authorized amount. A fundamental tenet of forecast test year ratemaking is that the utility retains the discretion between the test years to manage its revenues and activities as it sees fit, consistent with its obligations to provide safe, reliable, environmentally sound utility service. Although we review the utility's request on an account-by-account basis, for the most part, the ratemaking adjustments we make to PG&E's budgets are not binding on PG&E.

We caution PG&E that our approval of a "high level" forecast in this GRC should not be interpreted to mean that there is any doubt regarding whether or not PG&E was authorized funding to accomplish the various objectives set forth in their application. An essential factor in our finding that the Settlements are in the public interest is the understanding that, by virtue of its agreement to the TY 2003 revenue requirement provided in the Settlements, PG&E intends to fulfill the objectives stated in their GRC request. The Settling Parties confirm our understanding in the Motion to Approve the Generation Settlement, which represents that the Generation Settlement "permits PG&E to recover reasonable costs of necessary capital investments in, and operations and maintenance of, its generation assets." The Settling Parties further state that "the Settlement provides sufficient capital to allow PG&E to adequately maintain the facilities and ensure their long term availability to serve customers."[40]

Absent this type of commitment, we would be unable to find that the Settlements are in the public interest. We emphasize that claims by PG&E that a particular project or activity was not funded in this GRC will not be entertained simply because the total amount granted in this case is less than the total amount initially requested. This policy is consistent with our prior holding that "[I]t would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonable deferred maintenance, <u>or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past</u>. (D.00-02-046, Conclusion of Law 15, p. 536, emphasis added.)

In adopting the Settlements, we make it abundantly clear that PG&E is expected to continue meet all of its service obligations and maintain and upgrade its system in a manner consistent with its TY 2003 forecast. By providing PG&E with the discretion to spend the authorized revenue requirement as it sees fit, we are not authorizing PG&E to defer maintenance, cancel proposed upgrades or service improvements, or reduce staffing in a manner inconsistent with the

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[40] (Motion to Approve Settlement Agreement, p. 13.)

objectives identified in its request. In future GRCs, we will not entertain claims that the adopted revenue requirement somehow forced PG&E to do otherwise.

10. Other Issues

10.1 Pension Contributions

The only revenue requirement issue not addressed by the Settlements is PG&E's request that the Commission approve a TY 2003 forecast contribution to the Retirement Plan trust of $128.6 (total company). PG&E offers a tax-qualified pension plan, which provides benefits to employees upon retirement based on years of service, salary, and age at retirement. PG&E relied on Towers Perrin's analysis of the Retirement Plan's funded status in considering whether a contribution to the Retirement Plan trust was appropriate. PG&E calculated the requested contribution amount using what it refers to as the "normal cost" method to determine the pension fund contributions to be reflected in revenue requirements. PG&E states that under the normal cost method, the forecast pension cost is based on the cost of benefits earned by employees in the current year. PG&E claims that that normal cost method ensures that current customers will pay the cost of benefits earned by employees in the course of providing service to those customers. PG&E maintains that there is no risk to ratepayers if the PG&E normal cost method exceeds the Internal Revenue Service (IRS) maximum tax deductible limit because PG&E will credit back to ratepayers the associated revenue requirement that is not contributed to the trust or otherwise used for related pension costs at the end of the rate case cycle.

ORA urges the Commission to reject PG&E's request. ORA states that PG&E has not provided sufficient evidence to justify a $128.6 million pension plan contribution in 2003 and the subsequent three years to avoid a 25% probability of making a contribution of above $150 million in 2007 absent such a contribution. ORA notes that no contribution is currently required by the IRS/Employee Retirement Income Security Act (IRS/ERISA) minimum contribution and maximum tax-deductible contribution limits and that PG&E's proposed funding is voluntary. ORA argues that there is risk to ratepayers because any refunds would not be approved until the year 2006 at the earliest, or after 2007 if the Settlement is adopted.

10.1.1 Discussion

We review PG&E's Pension Contribution request pursuant to Pub. Util. Code § 451 and 454, which provide that no public utility shall change any rate or charge except upon a showing before the Commission and a finding, by the Commission that a change is just and reasonable.

Although PG&E is correct that the minimum ERISA contribution is not an accurate measure of the cost of benefits earned by PG&E's employees in a given year, the Commission has not advocated strict adherence to the normal cost method in determining whether a contribution is necessary or reasonable when doing so would not be in the ratepayers' interest. Nor has PG&E strictly held that it must make pension contributions annually based on the amount calculated by the normal cost method. In the years subsequent to 1992, the determination of whether to make a contribution to the Retirement Plan trust has been based on an evaluation of the funding status of the pension obligation, as measured by in part by investment performance, combined with an assessment of whether such a contribution would be tax deductible. Thus, the normal cost method has been used as a guide in calculating a contribution amount, rather than a hard and fast rule regarding whether such a contribution is necessary.

As ORA points out, using the normal cost method to determine whether a contribution is necessary essentially ignores the funding status of the pension obligation and the actual investment performance. ORA also points out that in D.00-02-046, the Commission approved PG&E's normal cost method for calculating the contribution amounts in theory, but did not approve or reject a particular funding amount, since PG&E reduced its funding request in that case to eliminate the amount proposed for pension contribution. ORA also notes that in approving the normal cost method in that case, the Commission indicated that it would consider other approaches to calculating pension funding in the future, stating: "future ratemaking proceedings may find a need for further consideration." (D.00-02-046, *mimeo.*, p. 311.)

Towers Perrin's actuarial analysis provided PG&E with both an estimate of the contributions according to a normal cost method of calculating pension costs, and an estimate that a contribution may be needed by 2007 to ensure full funding of the Pension Trust. According to the Towers Perrin analysis, minimum required contributions under ERISA are forecast to be zero for the years 2003 through 2005, and most likely zero in 2006, but the probability of needed contributions to the pension fund are 50% by the year 2007. Notwithstanding the fact that Towers Perrin does not find that a contribution is needed in 2003, Applicant requests funding for annual contributions beginning in the TY 2003.

As ORA notes, the applicant bears the burden of proving that its request is just and reasonable. In PG&E's last GRC, the Commission held that:

> "The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility..." (D.00-02-0246, *mimeo.*, P. 36, citing Re Pacific Bell (1987) 27 CPUC 2d 1, 21, D.87-12-067)

The Commission also held that standard of proof that applicants must meet is one of clear and convincing evidence. (D.00-02-046, Finding of Fact #.)

In order to demonstrate that its request is reasonable, PG&E must show, through clear and convincing evidence, that a voluntary contribution of $128.6 million per year is necessary at this time. The normal cost method makes sense in theory, assuming that in each year ratepayers are paying the appropriate amount. However, in reality, the contribution amount is determined based on the investment performance and funding status of the retirement plan.

In this case, PG&E has not provided sufficient evidence demonstrating that the current funding status of the plan requires a contribution in TY 2003. We note that the Towers Perrin analysis titled, Pacific Gas and Electric Company Retirement Plan - PG&E Gas Transmission Northwest Retirement Plan – Impact of Market Decline on Contributions and Funded Status, dated August 20, 2002, indicates that the funded percentage of the plan, including the effect of the 2002 market decline is 110%. (Exhibit 22, p. 19A-6.)

We find that the need for ratepayer contributions to the Retirement Plan trust in any given year must be determined based on the funding status of the plan. To do otherwise would be inconsistent with our obligation, under Pub. Util. Code § 451 to provide for just and reasonable rates. We find that it would be unreasonable to approve a request for pension contribution in TY 2003 based on a showing that there is a 50% probability of a minimum contribution by the year 2007. Accordingly, we deny PG&E's request.

10.2 Diablo Canyon Independent Safety Committee (DCISC)

PG&E's application included a proposal to terminate the DCISC on the basis that Diablo Canyon is no longer subject to performance based pricing as established in the settlement which created the committee. The DCISC and Mothers for Peace opposed this aspect of PG&E's application. The

February 13, 2003, ACR directed that a meet and confer session be held to develop procedural recommendations regarding the DCISC issues in the proceeding. On March 12, 2003, the Mothers for Peace filed a petition seeking to transfer a pending Petition to Modify D.88-12-083 from A.00-11-038 et al.[41] to A.02-11-017 et al. (the instant application).

On April 24, 2003, the PG&E, DCISC, ORA, Mothers for Peace, California Energy Commission (CEC) and TURN filed a Motion to Adopt a Stipulation (Stipulation)[42] under which: (1) the DCISC would continue to exist and be funded through cost-of-service rates at least through the next rate case cycle; and (2) the Commission will resolve the issues raised by the Petition to Modify D.88-12-083 in the context of PG&E's TY 2003 GRC; and (3) the Commission would hold one of the public participation hearings for the PG&E GRC in San Luis Obispo. The Stipulation is attached as Appendix C.

On April 28, 2003, ALJs Cooke and Wong issued a ruling transferring the Petition to Modify D.88.12-083 filed on November 29, 2001 to this proceeding. The April 28, 2003, ruling directed Mothers for Peace to update its Petition to Modify D.88-12-083 by filing a supplemental brief on May 23, 2003, and reply briefs on June 20, 2003.

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[41] By ruling dated December 6, 2001, the Chief ALJ determined that the Petition to Modify D.88-12-083 should be addressed in A.00-11-038.

[42] The Motion to Adopt the Stipulation was filed pursuant to Rule 51. As required by Rule 51, on April 4, 2003, PG&E held a noticed settlement conference to discuss the terms of the stipulation.

10.2.1 DCISC Background

The DCISC was created as the result of a settlement when the reasonableness of the costs associated with the Diablo Canyon Nuclear Power Plant was being examined. The committee was established to "review Diablo Canyon operations for the purpose of assessing the safety of operations and suggesting any recommendations for safe operation." (D.88-12-083, App. C, Att. A, Section I.1.)

Mothers for Peace filed its petition to modify D.88-12-083 on November 29, 2001. Responses to the petition were filed by the California Energy Commission (CEC), DCISC, and PG&E. A reply to the responses of PG&E and the DCISC was filed by Mothers for Peace.

On January 17, 2002, the Physicians for Social Responsibility – Los Angeles (PSR) submitted a pleading to the Docket Office entitled "Petition To Adopt, Amend, Or Repeal A Regulation Pursuant To 1708.5 and AB 301,[43] Petition To Establish A Safety Oversight Committee For San Onofre Nuclear Generating Station (SONGS) Units 1, 2 & 3." PSR's pleading stated in part that it was being filed in response to, and in support of, Mothers for Peace's petition to modify D.88-12-083. The Docket Office retitled the pleading as a response and subsequently, in a ruling dated February 22, 2002, the assigned ALJ ruled that PSR's pleading would not be treated as a separate petition under Section 1708.5 because it did not propose a rule "of general applicability and future effect;" the

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[43] Pursuant to Pub. Util. Code § 1708.5, interested persons may petition the Commission to adopt, amend, or repeal a regulation. The legislative intent underlying this statute construes a regulation to be a rule of general applicability and future effect.

ALJ also ruled that PSR's request for establishment of an independent safety committee for SONGS would not considered in connection with Mothers for Peace's petition.[44]

Two other petitions to modify D.88-12-083 were previously filed by the Mothers for Peace. The Commission denied those petitions in D.90-04-008 and D.91-10-020. In A.96-03-054, a proceeding determining the sunk costs of Diablo Canyon and the incremental cost incentive price of Diablo Canyon power, Mothers for Peace petitioned to set aside submission of the proceeding in order for the Commission to take additional evidence on the issue of safety impacts. The Commission denied the petition to set aside submission in D.97-05-088. Due to the requirements of AB 1890 (Stats. 1996, ch. 854), which froze customers' rates and accelerated the recovery of transition costs, D.97-05-088 also terminated the Diablo Canyon settlement but specifically directed that the DCISC continue operations until further order of the Commission. (72 CPUC 3d 560, 610.)

10.2.2 Request for Relief

On May 22, 2003, pursuant to the Stipulation, the Mothers for Peace submitted a revised petition to modify D.88-12-083. The revised petition seeks certain changes to the DCISC selection process, and a new requirement that DCISC establish an office in San Luis Obispo. Specifically, Mothers for Peace proposes the following changes to Attachment A of Appendix C of D.88-12-083.

[44] For the reasons stated in the ALJ's ruling of February 22, 2002, we confirm the ruling that PSR's January 17, 2002 pleading shall be treated as a response to the petition of the Mothers for Peace, and that PSR's pleading shall not be considered as a petition filed pursuant to Pub. Util. Code § 1708.5, nor will PSR's request for relief be entertained in connection with the petition filed by the Mothers for Peace.

- Instead of having the committee members selected from a list of candidates jointly nominated by the President of the Commission, the Dean of Engineering of the University of California at Berkeley, and PG&E, Mothers for Peace proposes that the members be nominated solely by the Commission through open requests for nominations. Mothers for Peace also suggests that a provision for seeking public comment on the candidates for the DCISC be created.
- Change the candidate selection criteria from "persons with knowledge, background and experience in the field of nuclear power facilities" to that of "persons with knowledge, background and experience in nuclear safety issues in the field of nuclear power facilities."
- Add a provision to Section I of Attachment A that would require the DCISC to "consist of at least one member from the San Luis Obispo public to represent the affected community."
- Add a provision to Section II of Attachment A that would require the DCISC to have an office and a local staff in San Luis Obispo. The current office in Monterey should be closed.
- Ensure that Section II.E. entitled "Compensation of the Committee" is enforced.
- Modify the DCISC mandate to explicitly include public outreach.

The petition alludes to several reasons for the proposed changes. First, Mother for Peace contends that "the DCISC has never been able to win the trust of the San Luis Obispo Community, nor the nuclear power plant employees, it was created to protect." Arguing that the community has been waiting over a decade for the additional assurance of safety promised in the Diablo Canyon settlement, Mothers for Peace contends that locating the DCISC in the San Luis Obispo area could help provide this assurance. Mothers for Peace maintains that locating the DCISC in San Luis Obispo would allow DCISC to attend meetings regarding Diablo Canyon, members of the public would have an easier time in contacting DCISC members and may result in improved access to DCISC documents, access which is currently limited by the availability of parking and restricted hours of library staff. For those members of the public that cannot attend meetings, Mothers for Peace recommends that the Commission direct PG&E to continue funding the video recording of DCISC meetings for broadcast on public access television.

Second, Mothers for Peace contends that in light of the California energy crisis, a fear exists that California will rely so heavily on nuclear power that safety issues, which Mothers for Peace contend have been downplayed by the utility, may be overlooked. Mothers for Peace asserts that in the last decade "economic pressures have resulted in rushing through refuelings and decreasing a workforce that has become demoralized and fatigued."[45] In addition, Mothers for Peace assert that credible safety oversight is needed now in light of PG&E's bankruptcy, and the need to protect nuclear power plants against terrorist attacks.

Third, Mothers for Peace asserts that the open nomination process for selecting the DCISC members will eliminate the conflict of interest in the current nominating process. Under the current screening process, Mothers for Peace asserts in its reply that "PG&E can effectively blackball any applicant that it wishes to keep off the Committee."

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[45] Similar safety issues were raised by Mothers for Peace in A.96-03-054, and rejected by the Commission in D.97-05-088. (*See* 72 CPUC2d at pp. 597-599.)

And fourth, Mothers for Peace believes that the Commission should examine whether or not the use of ratepayer funds for the DCISC has actually increased safety at Diablo Canyon. Mothers for Peace contends that it has not.

Although more than one year has elapsed since the effective date of D.88-12-083, Mothers for Peace asserts that the time limitation for filing a petition to modify must be waived because "many of the issues detailed in the Petition have arisen over the last decade, specifically in the last 2 years." (Petition, p. 3.) Mothers for Peace also asserts that safety issues continue to plague the nuclear industry, and that the additional assurance of safety that the DCISC was to provide is needed now more than ever.

10.2.3 Positions of the Other Parties

10.2.3.1 DCISC

The DCISC contends that there is no need to modify the composition and operations of the committee at this time. The committee argues that Mothers for Peace has failed to show good cause for changing the terms of the DCISC.

The DCISC points out that Mothers for Peace has raised concerns about the usefulness of the committee on three separate occasions over the last ten years. The Commission reviewed Mothers for Peace's request each time and determined that the committee did provide the additional assurance of safety, and that it should continue as initially established.

The DCISC contends that the current and external events cited in the petition have already been considered. For example, the DCISC requested and received detailed reports from PG&E in 2001 concerning the California energy situation and PG&E's subsequent election to file for bankruptcy protection. The DCISC has reviewed and considered these events, and has assessed the potential implications and impacts on the safety of operations at the plant and on the employees who are a vital part of the safety operations. The committee has also reviewed, evaluated and assessed the impacts of the electric deregulation efforts, the transition of the Diablo Canyon engineering staff from San Francisco to Diablo Canyon, PG&E's current Five-Year Business Plan, as well as the Nuclear Regulatory Commission's (NRC) evolving methods for providing nuclear safety oversight.

The DCISC has also followed and reviewed issues about nuclear security and the performance of Diablo Canyon's security organization. Following the events of September 11, 2001, the committee contacted PG&E about these types of issues, and responded to many concerns from citizens about these issues. In October 2001, the DCISC also received an updated report on security issues from PG&E, and a committee member and a consultant observed an on-site security exercise and briefing.

In response to the contention of Mothers for Peace that the committee has not provided an assurance of safety, the DCISC points out that over the last 11 years, it has considered and addressed numerous concerns about the safety of operations at Diablo Canyon, and that it has made 163 specific recommendations to PG&E to help maintain and improve safety at Diablo Canyon. PG&E has responded to each of these recommendations by taking acceptable action. The DCISC believes that these recommendations, and PG&E's actions in response to the recommendations, have significantly increased the assurance of safety and the margin of safety at the plant. Other examples of how the committee has been involved in the safety of the plant, and how this information has been disseminated to the public, are detailed in the committee's response to the Mothers for Peace's petition.

The DCISC does not believe the qualifications criteria should be changed to include background and experience in nuclear safety issues. Since the DCISC was created, all of its members have had direct technical experience in the safe operation of nuclear electric generating plants. The DCISC asserts that "one cannot really have knowledge, background and experience in nuclear safety issues unless one also has the broader knowledge, background and experience in the field of nuclear power facilities." (DCISC Response, pp. 15-16.)

As for the change in the nominating process, the committee states that past experience has shown that its members have been both qualified and independent. In addition, all committee members and consultants are prohibited from having any conflicts of interest. If the proposed nominating process change is adopted, the committee states that this will increase the Commission's burden by requiring review of the qualifications of a larger number of applicants.

Another proposed change is that at least one of the committee members be from the San Luis Obispo area. The DCISC does not oppose such a change as long as the expertise requirement applies to that member. The DCISC states that if one of its members lacks the requisite expertise in nuclear facilities, that this would substantially diminish the value and effectiveness of the committee. The petition also fails to address what would happen if there was no candidate from the San Luis Obispo area that had the required experience to serve on the DCISC. In addition, due to the staggered terms, several years could elapse before a member from the San Luis Obispo area actually serves on the committee. Although the petition asserts that a member from the San Luis Obispo area is needed to represent the interests of the affected community, the DCISC believes that these interests can best be represented through the appointment of the most qualified persons regardless of residency.

As for the request that the committee establish a San Luis Obispo office, the DCISC states that it has taken numerous steps to make the committee, its meetings, operations, and findings accessible to the public. Since the outset of its work, the DCISC has held a minimum of three public meetings each year in the San Luis Obispo area. Each meeting consists of technical presentations by PG&E representatives on plant operation and safety topics as requested by the DCISC and its consultants. The meetings also provide an opportunity for public comment, questions and communication to the committee and to the PG&E representatives. The notices of the meeting and the agenda items are published in local newspapers, as well as on the committee's website, www.dcisc.org. The committee members and consultants also conduct 8 to 10 fact finding visits to the plant and related facilities each year. Several of these visits are scheduled with an advertised evening open house session in San Luis Obispo. In addition, all of the annual reports of the DCISC are available to the public at the Cal Poly State University library in San Luis Obispo.

The DCISC contends that there is no evidence of a community-wide demand or request for a local office. Although the DCISC has considered the idea of a San Luis Obispo office, the committee has determined that such an office is not necessary to fulfill its safety mandates, and believes that available funds should be spent on technical experts and consultants to assist and advise the committee on safety and operations issues, instead of on office rent, overhead and staff. DCISC believes the office location issue should be left to the consideration and discretion of the DCISC.

10.2.3.2 California Energy Commission (CEC)

The CEC contends that the proposed change to the nomination process would avoid any perceived or potential conflict of interest.

The petition also proposes that the committee members have knowledge, background and experience in nuclear safety issues in the field of nuclear power facilities. The CEC contends that since the purpose of the committee is to assess the safety of operations at Diablo Canyon and to make recommendations for safe operation, it "appears eminently reasonable that the DCISC members have a background not just in nuclear plant operations, but in nuclear safety issues at nuclear plants." (June 19, 2003 CEC Comments, p. 3.)

According to the CEC, enlarging the committee to include "at least one member from the San Luis Obispo public to represent the affected community," is comparable to the composition of the CEC, which includes a Commissioner from the public at large.[46] The CEC supports this request.

With regard to the proposed change to require the DCISC to have an office and local staff in San Luis Obispo, the CEC states that a local presence might encourage more local residents to participate in the processes of the DCISC. The CEC recognizes that the purpose of the DCISC is to assess the safety of operations at Diablo Canyon and to make recommendations, and that these tasks could be done from anywhere. However, the CEC notes that local residents have an important stake in ensuring that a nearby plant is safely operated and are

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[46] The CEC notes that, pursuant to Public Resources Code section 25201, of the five CEC Commissioners, one member is appointed from the public at large, but is not required to have any specific energy expertise.

much more likely to participate in the DCISC process if there is local staff to assist them. The CEC also points out that only one of the current DCISC members is a California resident.

10.2.3.3 PG&E

PG&E's response recommends that the petition be rejected as moot, untimely, and without any basis in fact.

PG&E contends that the petition fails to cite any facts in support of the assertion of heightened safety concerns at Diablo Canyon. PG&E points out that "Safety is and has always been PG&E's highest priority at Diablo Canyon," and that the plant is recognized by the NRC as one of the best run and safest nuclear power plants in the country. PG&E also notes that the "NRC has added increased inspection and has inquired into the potential impact of PG&E's bankruptcy on operations and has been satisfied that there have been no adverse impacts on Diablo Canyon operations or safety." (PG&E Response, p. 3.)

With regard to potential threats of terrorism, PG&E states that the NRC has responded by implementing appropriate responses, and that additional measures are being evaluated by the NRC. PG&E asserts that Mothers for Peace has failed to demonstrate or even suggest how the petition, if implemented, would further these efforts.

PG&E contends that there is no reason to modify the process for selecting the DCISC members. Past experience, as shown by the professional background and diversity of the current and former members of the committee, refutes Mothers for Peace's arguments for changing the nominating process. PG&E points out that all of the committee members and consultants must avoid conflicts of interest and file annual statements of economic interest confirming that.

PG&E asserts that the proposed nominating process change would to change the member selection into a partisan political appointment process, and would not further the goals and mandate of the DCISC. In addition, if the proposed requirement to add a member from the San Luis Obispo area is adopted, PG&E contends that this could result in a very limited pool of qualified applicants, and could lead to the forced appointment of candidates who lack the appropriate expertise.

If the petition was intended to increase local participation, PG&E points out that the committee already conducts three public meetings each year in the San Luis Obispo area. Notice of the dates, times, and locations of these meetings is widely disseminated. All of these meetings provide the public with the opportunity to speak and provide information to the committee. PG&E also points out that the committee has a web site, and that the committee is responsive to any inquiries that it receives from the public.

PG&E also contends that the petition is improper under the Commission's rules because the Mothers for Peace has failed to meet its burden to as to why the petition was not filed within one year of the effective date. In addition, PG&E asserts that the Mothers for Peace has failed to adequately allege and support facts in support of its petition.

10.2.3.4 ORA

ORA supports the addition of a qualified public member to the DCISC as a means of both adding expertise and improving local involvement. ORA notes that the addition of a fourth member will increase DCISC expenses.

ORA also supports the Mothers for Peace request to revise the nomination process to eliminate direct involvement by the Dean of Engineering of the University of California at Berkeley (Dean of Engineering) and PG&E,

substituting an open request for nominations. ORA states that there was never a good reason for permitting PG&E to nominate members to what is supposed to be an "Independent" committee, therefore removing PG&E from the direct nomination process would enhance the credibility of the DCISC. ORA believes that there is no reason to continue to ask the Dean of Engineering to nominate candidates for the DCISC. According to ORA, an open request for nominations will "cast the widest possible net for potential nominees, and still permit PG&E and the Dean of Engineering to offer their own nominees, if they so choose." (ORA Reply Brief, dated June 20, 2003, p.4.)

ORA also recommends that the Commission order PG&E to resume funding the videotaping of DCISC meetings. ORA believes that broadcasting DCISC meetings on the local cable access channel is a low-cost and efficient means of providing the public information on Diablo Canyon and the DCISC, especially for members of the public who cannot attend meetings.

10.2.4 Discussion

10.2.4.1 Stipulation

The first issue to be addressed is whether to approve the Stipulation. The Stipulation contains two primary components.[47] First, the Stipulation reflects the agreement among the Stipulating Parties that the DCISC should continue to exist and be funded in cost-of-service rates through the next rate case cycle, at funding

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[47] A third agreement, that, "the Commission should plan to hold one of the public participation hearings for the PG&E 2003 GRC in San Luis Obispo" is not discussed because it has already been effectively approved and is therefore moot. The Commission held a public participation meeting in A.02-11-017 in San Luis Obispo on August 27, 2003.

levels established by the Commission in D.97-05-088 of $673,077, plus 1.5% annual escalation. The 2003 funding, based on the 1.5% escalation rate, is $747,011. To implement this agreement, PG&E agrees to withdraw its proposal to eliminate the DCISC from its TY 2003 GRC application.

Second, the Stipulation reflects the agreement among the Stipulating Parties that the Commission should resolve in the final decision issued in the TY 3000 GRC the issues raised in the Mothers for Peace Petition to modify D.88-12-083 regarding the DCISC nominating and appointment procedures, expertise and residence requirements, and location of the DCISC staff and offices. The Stipulating Parties agreed that, in lieu of evidentiary hearings, Mothers for Peace should file a supplemental brief and parties should file reply briefs addressing the issues raised by the Mothers for Peace Petition to Modify D.88-12-083. Until a decision is issued on the Mothers for Peace Petition, Appendix C of D.88-12-083 (the terms of which Mothers for Peace's petition would change) would remain in place. To the extent that the Commission grants all or part of the Mothers for Peace Petition, the modifications should be prospective. To the extent that the modifications result in an increase in costs associated with the DCISC beyond the funding levels authorized in the TY 2003 GRC, the Stipulating Parties agree to support recovery of those additional cost through an attrition mechanism or submission of a supplemental application.

Prior to approving any stipulated agreement or settlement, the Commission must find that it is in the public interest. We find that the Stipulation, attached as Appendix C to this decision, which addresses certain of the DCISC issues in this proceeding, is in the public interest. The Stipulation provides for a mutually acceptable outcome to an issue (the continued existence of the DCISC) in a pending proceeding, thereby avoiding the time, expense, and uncertainty of litigation on this issue. The Stipulation represents the interests of the applicant as well as all other active parties who filed responses, comments or briefs on this issue. No party opposes it.

10.2.5 The Revised Petition to Modify D.88-12-083

The first change that the petition seeks to make is to have the Commission nominate all of the members of the committee through an open request for nomination. The petition also seeks to create a process for public comment on the applicants. The proposed change, if adopted, would affect Section I.2. of Attachment A to Appendix C of D.88-12-083.

The existing nomination process involves compiling a list of three candidates who are jointly nominated by the President of the Commission, the Dean of Engineering, and PG&E.[48] The committee member whose term is expiring is deemed to be an additional nominee. These names are then forwarded to the appointing authority. The appointing authority rotates with each appointment among the Governor, the Attorney General, and the Chairman of the CEC.

Mothers for Peace seeks this change because it believes the change will eliminate a potential conflict of interest with PG&E and the Dean of Engineering, and that the open nomination process will reestablish the trust of the San Luis Obispo residents and the Diablo Canyon employees. ORA and the CEC agree,

[48] If the joint nominating bodies cannot agree upon the three nominees, each nominating body is to submit to the other two a list of two nominees. Each nominating body can then strike any one of the four names proposed on the other two nomination

Footnote continued on next page

arguing that this change would enhance the DCISC's credibility by removing any perceived or potential conflict of interest and offers the advantage of public comment. ORA also believes that this change would make the process more efficient, suggesting that there is no reason to continue to ask the Dean of Engineering to nominate candidates for the DCISC.

We agree. Although no party has demonstrated that the existing nominating process has resulted in the appointment of committee members who are biased in favor of PG&E, we have before us an improvement to the existing process that would both streamline the nomination process and eliminate any potential concerns regarding conflict of interest. PG&E notes in its response that, "the composition of the DCISC and the nominating and appointment structure for selection of its members was carefully negotiated" as part of the settlement that resulted in D.88-12-08 and should not be changed. However, as PG&E acknowledged in its initial request to disband the DCISC, the settlement adopted in D.88-12-083 is no longer in effect. D.88-12-083 found that "Safety Committee will be useful monitor of the safe operation of Diablo Canyon"…"subject to our oversight…to determine the reasonableness of its activities." (30 CPUC 2d, p. 266.) Modifying the nomination in response to a reasonable request is an appropriate exercise of our oversight responsibilities.

The second change that the petition seeks is the requirement that DCISC nominees have "knowledge, background and experience in nuclear safety issues in the field of nuclear power facilities." The existing requirement only specifies

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lists. The names remaining after the exercise of this right to strike are then submitted to the appointing authority.

that the nominees have "knowledge, background and experience in the field of nuclear power facilities."

The safety issues of nuclear power generation are an inherent component of nuclear power. The DCISC was created "for the purpose of assessing the safety of operations and suggesting any recommendations for safe operation." (D.88-12-083, Appendix C, Attachment A, Section I.1.) With that purpose in mind, the committee members have to focus on the safety of operations in order for them to perform the work that is required of them. The experience requirements should reflect this purpose and focus. However, nominees should continue to be required to have knowledge, background and experience in nuclear power facilities. We will revise this requirement such that Paragraph C of Appendix C shall read as follows:

"The President of the CPUC shall propose as candidates only persons with knowledge, background, and experience in the field of nuclear power facilities and nuclear safety issues."

As a side note, our review of the qualifications of the past and present members of the DCISC, which was attached as Exhibit C to the committee's response, demonstrates that all of the committee members have a background in nuclear safety issues. Accordingly, we do not anticipate that this change will significantly effect the composition of the DCISC.

PSR also raised the issue that Diablo Canyon might be sold to another operator sometime in the future, and that such a sale could affect the safe operation or decommissioning of the plant. Any sale of this sort would have to be approved by both the NRC and this Commission. That kind of issue is more appropriately addressed when and if such a sale is proposed.

The third change proposed by Mothers for Peace is that the membership on the DCISC be broadened to "include at least one member from the San Luis Obispo public to represent the affected community." This request would change the number of committee members from three to four, and the fourth member from San Luis Obispo would be required to meet the same experience criteria as the other committee members.

There is currently nothing to prevent a resident of the San Luis Obispo area, with the requisite background and experience in nuclear power facilities, from seeking nomination and appointment to the DCISC. Although a local resident on the committee might be able to promote a better relationship and understanding with the local community, the qualification requirement and the conflict of interest prohibition might significantly limit the pool of eligible nominees from the local area. Accordingly, the proposed change to add as a fourth member of the DCISC a member of the San Luis Obispo public should not be adopted.

The fourth proposal of Mothers for Peace is that the compensation provision in Section II.E. of Attachment A to Appendix C of D.88-12-083 be enforced. The only apparent reason for this proposal is that Mothers for Peace believe that the Commission should investigate whether the use of ratepayer funds for the DCISC is actually increasing safety at Diablo Canyon.

The compensation provision provides in pertinent part:

> "Members of the committee shall be compensated in an amount established by the CPUC, to be commensurate with fees PG&E pays for similar services. The fees and expenses of the committee and its contractors shall be paid by PG&E and included in its ordinary rate base operating expenses. The fees and expenses shall not exceed $500,000 in the first year; thereafter, the $500,000 shall escalate at the same rate as the total price set for Diablo Canyon generation."

Although Mothers for Peace may disagree that the DCISC is providing the additional assurance of safety that was expressed in D.88-12-083, there is an ample record that the committee has been actively fulfilling its duties as reflected by the public meetings it holds in the San Luis Obispo area, the annual reports that it prepares, the recommendations that it makes to PG&E, and other activities of the committee members. To date, the DCISC has prepared 11 annual reports, and has made over 160 recommendations to PG&E. These recommendations are then followed up by the committee in subsequent meetings. The DCISC has also solicited the input of the San Luis Obispo community at its public meetings. Mothers for Peace has not presented any evidence that the DCISC's compensation or funding is not being used to promote an additional assurance of safety at Diablo Canyon. The fourth proposal of the Mothers for Peace should not be adopted.

The fifth proposal is for the Commission to require that the DCISC have an office and local staff in San Luis Obispo, and that the office in Monterey be closed. The recommendation to require that the committee establish its office in the San Luis Obispo area seems reasonable since the Diablo Canyon plant is located in that area. A local office, rather than an office located in Monterey, would make the DCISC more accessible to the residents of the area. Although the DCISC can be readily contacted by electronic mail, or by calling a toll free number, we are sensitive to the concern that the DCISC is not accessible. And, contrary to the DCISC's assertion that there has been no public request for an office in San Luis Obispo, the record in this proceeding includes public comments from at least 35 separate individuals at the public participation hearing conducted in San Luis Obispo, most of whom addressed either the DCISC specifically or Diablo Canyon generally and several of whom requested a local office. We agree with the Mothers for Peace that to the extent that the DCISC has an office, the location of the office should be in San Luis Obispo. We note that, to date, DCISC has apparently been operating out of the office of its counsel, in Monterey, and we appreciate that this decision was made in order to conserve funding. Moreover, after reviewing D.88-12-083 and Appendix C of that decision, it is not clear whether the work scope of the DCISC was intended as a full-time operation with a full-time staff. D.88-12-083 left the issue of how best to accomplish its mandate to the DCISC. With this fact in mind, we will deny Mothers for Peace's request that we order the DCISC to establish an office in San Luis Obispo. However, we strongly encourage the DCISC to reconsider its office location, and establish an office in San Luis Obispo instead. The fifth proposed change of the Mothers for Peace is not adopted.

Finally, Mothers for Peace requested that the Commission direct PG&E to resume funding of videotaping services for the DCISC meetings. Mothers for Peace maintains that this is a relatively inexpensive way to allow local residents to understand and participate in the DCISC process. ORA agrees. According to ORA, the cost of the videotaping services is approximately $2,000 per meeting. We agree with Mothers for Peace and ORA and direct PG&E to continue, or resume funding the videotaping of the DCISC meetings.

10.3 Compensation Issues

10.3.1 Executive Compensation

Greenlining filed testimony recommending, among other things, that the Commission encourage PG&E to link executive compensation to the level of philanthropic contributions, workforce diversity, and meeting performance goals related to Supplier Diversity.[49] Greenlining suggests that PG&E's executive compensation is excessive and, in relation, its performance with respect to philanthropic contributions, workforce diversity and supplier diversity is inadequate.

Greenlining recommends that the Commission take several steps in order to mitigate these problems. First, Greenlining recommends that the Commission require PG&E to report annually on the total compensation package for each of PG&E's top ten executives, including the value of stock options, retirement plans, and any other compensation not currently reported under GO 77-K. Next, Greenlining recommends that the Commission scrutinize the composition of PG&E's Nominating and Compensation Committee. Third, Greenlining suggests that the Commission encourage PG&E to tie executive compensation to the level of philanthropic contributions and to meeting or exceeding supplier diversity and workforce diversity goals. Greenlining recommends that no bonuses should be paid if the goals of GO 156 are not met.[50] Fourth, Greenlining also recommends that the Commission encourage, if not require, PG&E and

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[49] In response to a request from PG&E, at the prehearing conference on May 21, 2003, the ALJ struck portions of Greenlining's initial testimony related to GO 156 exclusions, and directed that those issues be addressed in R.03-02-035, the Commission's Rulemaking into revisions to GO 156. Greenlining filed a motion for expedited motion for full commission decision on inclusion of philanthropy and supplier diversity testimony in this GRC. In this decision we affirm the ALJ's ruling striking Greenlining's testimony regarding exclusions and deny Greenlining motion.

[50] GO 156 implements Pub. Util. Code §§ 8281-8286, and establishes goals for increasing the participation of women, minority, and disabled veteran business enterprises in utility procurement.

other utilities that have failed to achieve 15% in minority contracts to allocate additional funds for technical assistance to minority business associations, with the amount of funding based, at least in part, on the level of the total compensation packages of PG&E's top executives.

Finally, Greenlining recommends that the Commission encourage PG&E to ensure that at least two percent of its pre-tax income is awarded to philanthropic causes, with at least 80% of this allocated to groups serving the low-income community. Greenlining believes that these measures would both mitigate the negative effects of excessive executive compensation, such as "wage creep" and provide needed assistance to the low-income community.

TURN also expressed concern about the amount of executive compensation at PG&E and the Holding Company.[51] TURN argues that justifying increased payments by ratepayers for executive compensation using surveys of how other companies are paying their executives is circular, and that increases based on surveys and averages will beget further increases. (Exhibit 405, p.8.) TURN does not propose a disallowance in this GRC, but suggests that the Commission "require PG&E to file an executive compensation exhibit in the next GRC that includes compensation data contained on proxy statements for the last five years, identifying those costs for which ratepayer funding is requested, and justifying any increases in compensation above the

[51] TURN indicates that it is less concerned about the Holding Company if the Commission adopts ORA's recommendations regarding the allocation of Holding Company costs.

labor escalator from the period of 2001 (the base year in this GRC) through the test year for the next GRC." (*Id.*)

10.3.1.1 Discussion

As a preliminary matter, we note that employee compensation issues are appropriately within the scope of this GRC. To the extent that PG&E's base revenue requirement request includes revenues associated with employee compensation, it is required to identify its request, and demonstrate through clear and convincing evidence that its request is reasonable. For purposes of its compensation request in this proceeding, PG&E presented a Total Compensation Study prepared by Towers Perrin, and jointly managed by PG&E and ORA. The purpose of the study was to assess PG&E's compensation levels to determine PG&E's competitiveness relative to the market. The study defines total compensation as the combination of cash compensation (base salary plus short-term incentives[52]) and benefits (medical, dental, vision, life insurance, disability, pension, and savings plans). The study commenced in November 2000 and was completed in June 2001. (Exhibit 7, p.10-4.) The results of the study are presented in the table below.

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[52] For PG&E, short-term incentives are represented by the Performance Incentive Plan and are calculated based on a target incentive award of 50 percent of the maximum potential payout.

Towers Perrin Total Compensation Study Results

Job Grouping	PG&E's Position to Market
Executive	97.13%
Management and Supervisory	103.42%
Management Non-Supervisory/Technical	101.71%
Physical	105.33%
Clerical	113.39%
PG&E's Overall Position to Market	105.17%

Based on 141 benchmark jobs representing 51.5% of PG&E's employees,[53] the study found that PG&E's total compensation was 105.17% of the survey average; in other words, PG&E pays 5.17% more than the average of firms surveyed.[54] The Towers Perrin study results show that the compensation of PG&E's "Executive"[55] class was 97.13% of market levels.

After giving the matter careful consideration, we decline to adopt Greenlining's recommendations. First, Greenlining and PG&E jointly filed a petition in another proceeding that addresses the total compensation of top

[53] Excluding nuclear and temporary employees.

[54] ORA noted that the Commission has adjusted total compensation to reflect no more than 5% above market in previous PG&E GRCs, specifically, D.95-12-055 (63,CPUC 2d, p.633) and D.92-12-057 (47 CPUC 2d, p. 304), in which the Commission reduced PG&E's request for total compensation from 7.93% to 5% and from 8.5% to 5%, respectively, however, based on the surveys results finding that PG&E's total compensation is 5.17% above market levels, ORA did not recommend that the Commission adjust PG&E's request.

[55] The total population of the Executive class used in the study was 20 positions, of which 12 were included as the benchmark sample. Exhibit 7, p. 10-7 (page 5 of the Towers Perrin Total Compensation Study Report) lists the Total Compensation associated with the 20 positions in PG&E's Executive category as $7,562,580.

executives. (Joint Petition dated January 30, 2004 in R.03-08-091.) We encourage PG&E to honor its voluntary pledge to provide such information, but we do not prejudge the outcome in the other proceeding, and decline to adopt Greenlining's recommendation in this proceeding to require PG&E to annually report on the total compensation package of its top ten executives.

Second, we are not persuaded to further scrutinize the composition of PG&E's Nominating and Compensation Committee. Greenlining vaguely claims that certain past behavior of one Committee member may demonstrate that he is not 'in touch with the common man or ratepayer sentiment,' but Greenlining reaches no hard conclusion. We are not convinced by this equivocal assertion that we may or should meddle in the composition of the Board of Directors. We take no position on the composition of the Board as a whole, and we similarly decline to do so for particular committees.

Third, we decline Greenlining's request to encourage PG&E to tie executive compensation and philanthropic contributions. The California Supreme Court has upheld our policy of excluding charitable contributions from authorized rate recovery. (Pacific Tel. & Tel. Co. v. Public Util. Comm. (1965) 62 Cal. 2d 634, 669.) The corollary of our policy to exclude from rates the expenses incurred by a utility for its philanthropic practices is that this Commission will not, as part of its ratemaking responsibilities, interject itself into utility management decisions regarding corporate philanthropy. Therefore, we find no basis upon which to adopt any of Greenlining's recommendations.

Fourth, for the same reason as stated above, we decline to adopt Greenlining's recommendations to encourage PG&E to award at least two percent of its pre-tax income to low-income philanthropic causes, with at least 80% of this allocated to groups serving the low-income community.

Finally, we find TURN's request that we require PG&E to justify any increases in compensation above the labor escalator in the next GRC reasonable, as it will provide additional information on which to consider compensation issues. Although any party, including TURN, could extract this information itself from proxy statements, and submit an exhibit tied to a labor escalator, the burden of proof remains with PG&E. We recognize that the forces of supply and demand largely control compensation levels. Whether or not considering executive compensation studies based on other companies to test compensation levels for PG&E introduces circularity, compensation levels at competitive employers must be considered in order to promote the attraction, motivation and retention of utility employees. Surveys of other companies, while relevant, are not the only measure in determining whether or not the utility's requested compensation is just and reasonable. Therefore, while we will continue to require that the utility and ORA jointly conduct a compensation study, we will also adopt TURN's recommendation.

10.3.2 Retention Bonuses

In January 2004, PG&E Corporation awarded $84.5 million in retention bonuses to 17 executives pursuant to a Senior Executive Retention Program (SrERP). These bonuses vested only days after PG&E Corporation (the holding company), PG&E (the utility) and the Commission entered into a Modified Settlement Agreement (MSA) regarding PG&E's emergence from bankruptcy. (D.03-12-035.) The size and timing of these bonuses raised concerns regarding ratepayer impact and public policy.

We have given the issue special attention. We find that none of the $84.5 million has been, or will be, charged to ratepayers. We adopt additional accounting and reporting measures to further ensure that the $84.5 million is charged to shareholders, not ratepayers. We are appalled at the size of the award, and encourage the senior executives to voluntarily return any amounts not needed to meet the program's purpose, or that are unreasonable or inequitable. The matter is now in the hands of the 17 senior executives, PG&E's shareholders and the California Legislature.[56]

10.3.2.1 Background

In December 2000, the PG&E Corporation Nominating and Compensation Committee of the Board of Directors[57] adopted the PG&E Corporation SrERP. This program sought to retain 17 key officers of PG&E Corporation, PG&E and National Energy Group (NEG)[58] through the difficult period of the energy crisis and the financial insolvency and bankruptcy of PG&E Corp.'s non-utility affiliates and PG&E's voluntary bankruptcy petition by the granting of restricted phantom stock units.

The SrERP was structured to promote retention of key corporate officers by the use of both time-based and performance-based incentives. Under the time-basis, one-half of the grants would vest on December 31, 2004. Under the

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[56] The Assembly is considering a bill that would (a) require any expense resulting from a bonus paid to an officer or employee of an insolvent public utility to be borne by shareholders and not ratepayers, and (b) provide that no income tax deduction be allowed for the costs paid or incurred during the taxable year by a public utility for any bonus paid to an officer or employee during the period the utility is insolvent. (Assembly Bill 2303, introduced on February 19, 2004, by Assembly Member Leno.)

[57] According to PG&E, it is now known as the PG&E Corporation Nominating, Compensation, and Governance Committee of the Board of Directors.

[58] This affiliate performs electric power generation and natural gas transmission. As it seeks to emerge from bankruptcy, the bankruptcy court judge has authorized a name change to National Energy & Gas Transmission, Inc.

performance-basis, the other half would vest only if PG&E Corporation's performance, measured by total shareholder return (TSR) on a cumulative basis, was at or above the 55th percentile of a comparator group of 11 companies for the four-year period from January 22, 2001 though December 31, 2004. Vesting could be accelerated by one year, to December 31, 2003, if at the end of 2003 PG&E Corporation's performance measured by TSR on a cumulative basis was at or above the 75th percentile of the comparator group.

The program required that the officer be employed on the vesting date, with some exceptions. The grant would be forfeited, however, in the event of an officer's resignation or termination for cause. To initiate the program, restricted phantom stock units of 3,044,600 shares were granted at a total value of $34,500,000 (*i.e.*, an average of $11.33 per share). The grants were payable in cash during January of the year following vesting, unless an officer elected to defer payment.

PG&E Corporation met the performance results for accelerated vesting. The phantom restricted stock units vested on December 31, 2003 at $27.77 per share, for a total value of $84,548,542. In summary, the awards were:

SENIOR EXECUTIVE RETENTION PROGRAM
ELIGIBILITY LIST

LINE NO	TITLE	RETENTION PAID PER OFFICER ($MM January 2004)
PG&E CORPORATION AND PG&E		
1	Chairman, CEO, and President	$17.1
2	Sr. VP / President and CEO PG&E	10.0
3	Sr. VP and CFO	6.4
4	Three Sr. VPs	3.6
5	Four Sr. VPs	2.7
6	Subtotal (10 Officers)	54.8
NATIONAL ENERGY GROUP		
7	EVP / President and CEO	7.4
8	Three Sr. VPs / Presidents and COOs	4.8

9	Three Sr. VPs	2.7
10	Subtotal (7 Officers)	29.8
TOTAL PROGRAM		
11	Total (17 Officers)	84.5

10.3.2.2 Executive Compensation Programs Generally

PG&E Corporation and PG&E, like other companies, use these compensation programs to meet a number of objectives. Among those objectives are attraction, motivation and retention of employees.

According to PG&E, its compensation program for officers and key employees includes:

a. base compensation (also called base salary or annual salary);

b. short-term incentive plan (STIP - also called Performance Incentive Plan);

c. long-term incentive plan (LTIP);

d. supplemental retirement savings plan (SRSP);

e. supplemental executive retirement plan (SERP);

f. executive stock ownership plan (ESOP);

g. retention mechanisms - including SrERP; and

h. other (*e.g.*, financial planning services, parking, health screenings, reimbursement for non-business related travel).

(PG&E Report Regarding Executive Compensation, February 10, 2004, pp. 2-3, 6-16.)

10.3.3 SrERP Is Funded By Shareholders, Not Ratepayers

10.3.3.1 SrERP Costs Are Not In Test Year Rates

PG&E states that it only requests the costs of two components of employee compensation for inclusion in TY 2003 rates: base salary and STIP. (*Id.,* p. 11.) To put this in perspective, we note that PG&E's total compensation levels are

105.17% of market average (*i.e.*, 5.17% above market). (Towers Perrin Study, Exhibits 7 and 22 cited in PG&E Reply Brief, page 20.) We conclude that PG&E's total compensation for all employees is equivalent to the market level. Similarly, PG&E's executive compensation is 97.13% of market (*i.e.*, 2.87% below market), (*Id.*,). We again conclude that PG&E's executive compensation is equivalent to the market level. We also note that executive compensation measured by this study does not include SrERP.

We have no information or reason to believe that Settling Parties added compensation components beyond base salary and STIP, and we find the overall Settlement reasonable without dissecting total and executive compensation elements of the Settlements. To the extent applicant only requests base salary and STIP, we only adopt those components in authorized rates. As a result, we find that TY 2003 rates do not include any amounts for retention programs.

Specifically regarding SrERP, shareholders will fund the entire $84.5 million. PG&E states that it has not sought, and states that it does not intend to seek, recovery of SrERP costs through its regulated utility revenue requirement. Moreover, PG&E says that: "PG&E Corporation shareholders have funded the $84.5 million Senior Executive Retention Program." (*Id.*, p. 11.)

Nonetheless, estimated SrERP expenses were allocated and booked as accruals in 2001, 2002, and 2003 to recognize future expenditures, as required by generally accepted accounting principles, according to PG&E. PG&E says that these accruals were recorded in Account 923 for 2001 and 2002, and Account 426 for 2003. PG&E reports that most or all of Account 923 is considered "above-the-line" (*i.e.*, generally eligible for recovery from ratepayers), while Account 426 is "below-the-line" (*i.e.*, generally not eligible for recovery from ratepayers). Although the accruals in Account 923 were "above-the-line," PG&E

states that these amounts were not used to develop PG&E's TY 2003 Revenue Requirement request. PG&E states that ORA's audit confirmed that PG&E excluded the cost of stock options and deferred compensation from its TY 2003 forecast.[59] (Exhibit 306 9-33.)

Further, PG&E says that it included these expenses in certain memorandum and balancing accounts used to book generation costs for later ratepayer recovery. Specifically, PG&E asserts that it booked about $166,000 of accrued expenses in 2001, and $807,000 in 2002 (*i.e.*, $973,000 for the two years).

PG&E states that these expense entries did not affect its CPUC-jurisdictional rates, or the amount customers paid in those years, however, because electric rates were "frozen." PG&E continues:

> "Nevertheless, to assure the Commission that this $973,000 of [SrERP] Program expense is accounted for consistent with "below-the-line" treatment, PG&E is adjusting these entries out of the regulatory memorandum and balancing accounts in 2001 and 2002." (Supplemental Report, February 27, 2003, page 4.)

PG&E's claim that the expense entries did not affect ratepayers due to the rate freeze is not entirely accurate. PG&E is correct that the expense entries did not affect jurisdictional rates, or the amount customers paid in those years due to the rate freeze. However, under the rate freeze the difference between the revenues at the frozen rates levels and the actual costs of providing utility service, often referred to as "headroom," is used to pay for procurement and energy crisis – related undercollections. To the extent the expense entries

[59] ORA notes that the cost of stock options and deferred compensation totaled $3.9 million in 2002.

associated with the SrERP were entered into Account 923 and other memorandum and balancing accounts, less revenues are available for headroom.

We concur that PG&E should adjust these accounts to ensure that there is "below-the-line" treatment. PG&E should include verification of such adjustment in an advice letter, as discussed further below.

10.3.3.2 SrERP Does Not Reduce Headroom Or Increase Rates

PG&E also reports that the January 2004 SrERP payments were made from PG&E Corporation's cash on hand. PG&E says PG&E Corporation has billed PG&E $53.2 million for its share, and the amount is payable to PG&E Corporation upon emergence from bankruptcy. PG&E concludes that: "These amounts do not reduce 2003 'headroom'; nor are they included in the 'regulatory asset' approved in the same decision [D.03-12-035]." (February 10, 2004 PG&E Report on Executive Compensation, page 23.)

This is fully consistent with our expectation and order regarding any retention bonuses related to PG&E Corporation, PG&E and NEG, including SrERP:

> "For purposes of calculating the headroom for 2003 (including the amount beyond the $875 million cap), in no event may the litigation costs, bankruptcy-related costs or any costs of PG&E Corporation or of any other PG&E affiliate be included in the determination of the headroom amount nor may any retention bonuses of PG&E's directors, officers, managers or any other employees be included in such a determination." (D.03-12-035, Ordering Paragraph 4.)

This direction is similarly applicable to any SrERP payments made in 2004. Both the $84.5 million of SrERP expenses in general, and the $53.2 million charged to PG&E in particular, are ineligible for recovery from ratepayers via existing rates, the TY 2003 revenue requirement, TY 2003 rates, headroom, the regulatory asset, or any other ratemaking tools or rates that involve ratepayer funds.

PG&E states that it "will be making an advice letter filing at the Commission in the near future to demonstrate compliance with Ordering Paragraph 4." (Supplemental Report, February 27, 2004, page 5.) The advice letter filing should also show the adjustments from Account 923 described above. Further, it should track the SrERP payments made in January 2004 (whether or not the cash distributions were deferred) to demonstrate that they were not charged to ratepayers. Finally, it should include anything else reasonably necessary to ensure that ratepayers have not paid, and will not pay, any portion of the $84.4 million in SrERP expenses.

We expect staff to audit the accounting of the $84.5 million SrERP, including an audit as necessary of any or all of the items reported in the Advice Letter. We expect PG&E and PG&E Corporation to fully cooperate with staff.[60] To the extent the audit results in a finding that any SrERP costs were included in PG&E's TY 2003 revenue requirement request, these amounts are subject to refund.

This audit should also assess any amounts allocated to NEG (now NEGT) that might find their way into gas or electricity rates. That is, PG&E reports that the cost of service for Gas Transmission Northwest (previously Pacific Gas Transmission) is determined by FERC. PG&E further reports that, to the extent

[60] This is required of all public utilities and their holding companies pursuant to the Public Utilities Code and Commission decisions, but we emphasize here the importance of this routine obligation. (*See, e.g.,* Pub. Util. Code §§ 314, 581, 582, 584, 701.)

NEGT's senior compensation costs are included in Gas Transmission Northwest's rates, PG&E's bundled core gas customers pay a portion of these costs through interstate gas pipeline charges to the interstate gas pipeline providing their service. This in some cases is Gas Transmission Northwest, either directly or through a broker, according to PG&E. However, PG&E states that:

> "Gas Transmission Northwest's current rates were approved by the FERC in 1996 and would not include amounts related to the PG&E Corporation Senior Executive Retention Program or the Management Retention Programs." (February 10, 2004 Report, page 25.)

Based on PG&E's statement, we conclude that no SrERP costs are included in existing gas rates.[61] The auditors should bring any contrary finding, should there be one, to our attention.

Going forward, we also direct PG&E to specifically identify for this Commission any SrERP costs included in any applications pending at FERC. PG&E should bring such information to our attention within 10 days of the mailing date of this decision for any applications now pending at FERC, and within 10 days of the filing of any future applications at FERC. This will permit us the opportunity to oppose any SrERP costs included by an applicant in any rate requests before FERC for FERC-jurisdictional rates related to PG&E's electric or gas transmission services.

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[61] This statement, along with all statements in PG&E's February 10 and February 27 reports, was verified by an officer of PG&E as being truthful, and declared as such under penalty of perjury.

10.3.3.3 Conclusion

Thus, with the reversal of the identified entries in Account 923 plus the audit ordered above, we are confident that SrERP costs will not be charged to ratepayers. SrERP costs were not in existing rates, are excluded from PG&E's 2003 GRC request, are not included in the adopted revenue requirement, are not in adopted rates, and will not be funded through headroom, the regulatory asset, or any other rates or ratemaking devices paid or funded by ratepayers.

Further, we will oppose any SrERP costs that are included by PG&E in any rate requests sought in proceedings before the FERC for FERC-jurisdictional rates related to PG&E's electric or gas transmission services.

10.4 GO 77-K Report and Dividend-Related Advice Letter

Applicant states that, in order to ensure that stockholders—not ratepayers—pay retention grants, PG&E will list all such awards in its 2003 General Order (GO) 77-K Report and indicate the FERC account to which the payment will be billed. (February 10, 2004 Report, pages 22-23.) This will permit further verification that the amounts are "below-the-line" and funded by shareholders, not ratepayers.

We adopt PG&E's GO 77-K proposal, including the identification of the FERC account. The 2003 GO 77-K Report was due by March 31, 2004. In making its proposal here, applicant does not ask for an extension, and none is granted.

If, however, applicant's 2003 GO 77-K Report (as filed by March 31, 2004) did not include a list of the $84.5 million retention bonus awards and show the FERC account to which they were (or will be) charged, applicant shall provide that information by filing an amendment to its 2003 GO 77-K Report within 10 days of the mailing date of this decision. If the 2003 GO 77-K report did include data on the retention bonuses but not clearly identify the persons, retention bonus amounts and FERC account (*e.g.*, if they were included in an alphabetical listing of over 3,000 employees and not easily identifiable), applicant shall provide the information in a separate table. The table should only list SrERP recipients, and be filed as an amendment to its 2003 GO 77-K Report.

In another proceeding, PG&E proposes that each public utility with annual operating revenues over $1 billion include an additional table in its annual GO 77-K report. (Joint Petition of PG&E and Greenlining To Ensure Full Corporate Transparency of Executive Compensation, dated January 30, 2004, filed in R.03-08-091.) The table would list the total compensation of the top executive officers of the utility's holding company and the utility. It would include both compensation received and compensation granted but not yet received, and would be verified by an independent auditor. In its joint petition, PG&E states:

> "In the spirit of corporate transparency and leadership, PG&E commits, by June 30, 2004, to voluntarily provide such changes and reporting for the year ending December 31, 2003, and in the future without regard to any formal order from the CPUC." (Joint Petition, page 3.)

Without prejudging what we will do in R.03-08-091, we encourage PG&E to voluntarily include this additional table in its 2003 GO 77-K report, and to do so within 10 days of the mailing date of this decision.

Finally, PG&E is authorized to reinstate the payment of dividends on or after July 1, 2004, but may defer dividend payments until after July 1, 2005.

(D.03-12-035, Appendix C, page 2, Recital Item E.)[62] To further ensure that shareholders (not ratepayers) pay SrERP grants, we require PG&E to make an advice letter compliance filing within 10 days of the date that PG&E Corporation announces that it will reinstate the payment of dividends and knows its underlying total earnings and dividend rate. The advice letter should show the retained earnings[63] (total and per share) before and after the award of the $84.5 million SrERP, and the effect, if any, on dividends (total and per share).[64] If the earnings, dividends and charges for the $84.5 million in SrERP bonuses are not in the same period, the advice letter should identify the period when the $84.5 million was charged but apply the $84.5 million for illustrative purposes in the same period covered by the earnings and dividends. This will illustrate that shareholders have funded these bonuses, and the effect of shareholding funding. PG&E shall serve a copy of either the advice letter, or a notice of its availability, on the service list for this Phase 1 GRC proceeding.

10.4.1 Voluntary Return of Bonuses

With this explanation of ratemaking treatment plus the compliance filings, we are confident that ratepayers have not been, and will not be, obligated to fund

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[62] "PG&E has told the financial community that it does not expect to pay a common stock dividend before the second half of 2005." (D.03-12-035, *mimeo.*, page 13.)

[63] After an audit by PG&E's independent certified public accountants.

[64] We would expect the difference in retained earnings to be about $0.21 per share based on $84.5 million and 400 million shares. (PG&E Corporation's Consolidated Quarterly Report for the period ending December 31, 2003, shows 401 million weighted average common shares outstanding; *see*: http://investor.pgecorp.com/quarterly.cfm.) At this cost per share, a shareholder with 1,000 shares will forego $210 in retained earnings as a result of the SrERP awards.

any portion of the $84.5 million in SrERP expenses. Nonetheless, we question the cost and reasonableness of the program, and call on the 17 senior executives to voluntarily return some or all of the SrERP bonuses.

The record provides several examples of corporate executives taking what some believe to be excessive compensation, and the resulting societal conflict and frustration.[65] Specifically regarding PG&E, individual Commissioners have spoken of their outrage at bankrupt companies paying enormous bonuses to retain officers, even when several of those officers are no longer with the company; PG&E's senior executives taking millions in bonuses at the same time that PG&E ratepayers are forced to pay billions of dollars to ensure that PG&E emerges from bankruptcy while PG&E shareholders forgo at least 13 quarters of dividends; and PG&E employees having to look on with likely extreme distaste at the very most senior PG&E management feathering their nests during this very difficult time.

Utilities and their parent companies have a unique role in the economy and society. They have special monopoly or quasi-monopoly status. They provide a critical and essential service to California residents and businesses. Their facilities are essential in maintaining and protecting public health and

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[65] For example, Richard Grasso of the New York Stock Exchange forced to resign after disclosure of $140 million compensation; David Coulter at Bank of America taking a $100 million severance package; Jack Welch of General Electric taking a pension with a guaranteed rate of return of more than 12% per year; John Snow of CSX Corporation and Donald Carty of American Airlines taking large pensions; Ken Lay of Enron taking $31 million total compensation in 2002 (such that removing his compensation alone reduced the average from $8.5 million to $6.3 million in a sample of Chairmen and CEOs from the Hewitt Study used by PG&E Corporation's Nominating and Compensation Committee); Jeffrey Skilling of Enron taking $30.6 million total compensation in 2002 (such that removing his compensation alone reduced the average from $6.2 million to $3.8 million in a sample of the next level executive down from Chairmen and CEO in the Hewitt Study used by PG&E Corporation's Nominating and Compensation Committee). (Exhibit 657, p. 5 and 11; Greenlining Opening Brief, p. 4-8.)

safety. In short, they are affected with the public interest, have a special public interest obligation and duty, and must be held to a high level of public trust.

In this light, utilities may seek recovery from ratepayers of each and every legitimate expense that provides benefit to ratepayers, and ratepayers must fund approved expenses. The SrERP provides no such benefit, however, as evidenced by applicant not even seeking recovery of SrERP costs from ratepayers.

Each utility may only charge ratepayers the just and reasonable costs necessary for the utility to provide safe, reliable and sufficient service. Similarly, we think that utilities and their holding companies should seek no more than just and reasonable amounts from shareholders.

The goal of the SrERP bonuses was to retain top officers during a difficult period, linking retention to time and performance. We question whether bonuses of over $80 million are needed to meet this goal. We question the necessity and reasonableness of paying $17.1 million alone to retain the top corporate officer. Even if some or all of these officers were retained, the difficult times continue with two companies not yet out of bankruptcy. Even when out of bankruptcy, the difficult times for PG&E ratepayers will continue.[66]

The record shows that socially responsible companies can do as well as or better than other corporations. For example, stocks of companies run more

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[66] For example, ratepayers will be obligated to pay relatively high rates by giving up any possibility of refunds of up to about $4 billion in headroom. Further, ratepayers must fund the $2.21 billion regulatory asset for up to 9 years. The Commission staff estimates that the net present value of the estimated ratepayer contribution to the settlement from headroom and the regulatory asset is about $7.1 billion. (D.03-12-035, *mimeo.*, page 45.) Ratepayers must also fund a return on equity of no less than 11.22% for several years.

selflessly perform better than those run by companies where executives put themselves first. (Exhibit 656, page 15.) Similarly, a Governance Metrics International study demonstrates a positive correlation between good corporate governance and corporate profit. (*Id.*)

Corporate officers should lead by example. If officers expect employees not to seek or take more compensation than reasonable and equitable, officers should similarly not seek or take more than reasonable and equitable. We call on the 17 senior officers to return to the shareholders any portion—or all—of the retention bonuses that were, or are, unnecessary to accomplish the goal of the retention program, or are either unreasonable or inequitable. PG&E should file a report with the Commission within 90 days of its next annual shareholders meeting that states whether or not any or all officers returned some or all of their retention bonus awards, and identifies the individual(s) and amounts returned, if any.

Voluntary return of compensation is not unusual in California. For example, the Governors in each of the last three administrations (Governors Wilson, Davis, and Schwarzenegger) have voluntarily returned some or all of their compensation in pursuit of larger goals. Each Governor also asked for a voluntary return, where possible, of some percent of the compensation paid to each of his most senior appointees in order to pursue these larger goals.

The senior executives of PG&E can follow the leadership of California's senior executive and his top appointees, along with his two most recent predecessors and their top appointees. Each PG&E officer should examine the issue, and do whatever he or she determines to be the right thing. The matter is now in the hands of each PG&E senior officer, PG&E's shareholders and the Legislature.

10.4.2 Workforce Diversity

Pursuant to the ACR issued on February 17, 2003, and a subsequent request from the ALJ, Applicant submitted testimony on its workforce diversity over the last 10 years, and its present and future plans regarding workforce diversity on March 17, 2003 (Exhibit 14) and April 18, 2003 (Exhibit 16).

PG&E has a company policy of providing equal opportunity in employment and advancement for all qualified persons without regard to race, color, religion, age, sex, national origin, marital status, pregnancy, sexual orientation, gender identity, or any non-job related factor. PG&E supports its diversity goals through an Affirmative Action Program. Other company-wide efforts to promote diversity include the Officer Succession Plan, of which 35 % of the 2002 Officer candidates identified were women and 21 % of the 2002 officer candidates were minorities, and the Leadership Development Initiative (LDI), a 15-month, comprehensive mentoring and development program designed to accelerate employee leadership development skills, increase diversity, and prepare participants for advanced career opportunities at PG&E. PG&E's current LDI class is 62 % women and contains 62 % minority representation. PG&E also works with various community groups, educational institutions and diversity organizations in an effort to ensure that it continues to attract employees from a diverse labor pool.

PG&E reports that in the past 10 years, its efforts have significantly increased women and minority representation at the officer, director, and manager levels and in almost every employee category. In 2002 minorities made up 40% of the PG&E's "Officer" category, 19.8% of the "Director" category, 20.1% of the "Manager" category, and 33.77% of the "Bargaining Unit" category, an increase in every category from the 1992 levels of 10.3%, 19.9%, and 9.2%, and

29.9%, respectively.[67] Within the "Bargaining Unit" category, minorities made up 29.1% of the "Bargaining Unit – IBEW Physical"[68] subcategory, and 35.1% of the "Bargaining Unit – ESC/IUSO"[69] subcategory, increases from the 1992 levels of 25.2% and 34.4%, respectively.

The percentage of women employees in PG&E's workforce increased as well. The only category where the percentage of women decreased is the "Administrative and Technical"[70] category, where representation by women decreased from 83.9 % in 1992 to 73.8 % in 2002. PG&E's diversity success has been recognized nationally by the U.S. Department of Labor. PG&E Corporation has also been included in Fortune Magazine's list of "America's 50 Best Companies for Minorities" five times, most recently in 2002.

Greenlining acknowledges that PG&E is a leader in the area of workforce diversity, but maintains that certain minority groups remain underrepresented on PG&E's board and in top executives. Greenlining recommends that the

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67 The data is presented in Table 1-1 of Exhibit 16.

68 Includes employees represented by the International Brotherhood of Electric Workers (IBEW) Local 1245. Job classifications within this category include line workers, equipment operators, and system operators.

69 Includes employees represented by the Engineers and Scientists of California (ESC) and the International Union of Security Officers (IUSO). Job classifications include Electric Distribution Engineer, Gas Distribution Engineer, Engineering Estimator, Mappers and Security Officers.

70 The "Administrative and Technical" category includes non-bargaining unit, non-exempt employees that are primarily clerical. This category includes small numbers of employees in technical positions such as senior inspector and aircraft mechanic. This category does not include any engineer positions or other exempt positions.

Commission: (1) encourage PG&E to set workforce diversity goals such as achieving at least 50% minorities on the board of directors and at least one-third minorities among the top 25 and top 100 employees by salary, (2) encourage PG&E to put more resources toward the development of qualified, experienced lower-level employees for promotion, (3) encourage PG&E to create a link between the company's success in the areas of workforce diversity and executive bonuses, and (4) require all utilities to file annual reports on workforce diversity, which would be presented and compared at a hearing conducted by the Commission.

10.4.2.1 Discussion

We decline to adopt Greenlining's recommendations. We find that PG&E has in place formal, effective programs and policies designed to enhance its workforce diversity in a manner consistent with state and federal laws. Moreover, the record shows that these programs have been successful in continually increasing the diversity of PG&E's workforce over the past 10 years. Greenlining has not demonstrated that PG&E is out of compliance with its affirmative action and/or equal employment opportunity obligations or any rule or order of this Commission. To the contrary, Greenlining agrees that "PG&E has a record in the area of diversity that is generally quite good particularly relative to other companies." (Exhibit 656, p.4.) PG&E has demonstrated that it complies with all relevant federal, state and local laws, regulations and ordinances related to workforce diversity, including Executive Order 11246, which requires all federal government contractors to include in every government contract an agreement not to discriminate against applicants and employees on the bases of race, color, religion, sex or national origin. PG&E

recognizes that "success in workplace diversity does not happen by accident but rather is the result of concerted efforts" (Exhibit 14, p.2-1.)

Based on the record in this proceeding, and our intention to require PG&E to update its workforce diversity statistics in PG&E's next GRC, we find Greenlining's request for annual reports on workforce diversity unnecessary and duplicative. We find no compelling reason to suggest changes to PG&E's workforce diversity program. Naturally, we will continue our ongoing review in this area, and in its next GRC application, PG&E should update the workforce diversity statistics presented in this GRC.

10.5 Service Drop Maintenance

Adams filed testimony objecting to PG&E's current practices of: (1) requiring customers to trim vegetation growing in the vicinity of a "residential electrical service lateral or drop wire," and (2) charging customers for trimming around service drops. Adams maintains that requiring customers to trim vegetation in the vicinity of service drops is inherently risky, and endangers both the safety of the individual and the reliability of the service drop. Adams argues that the alternative approach, charging customers for tree trimming services, is also unsafe because it gives customers a financial incentive to undertake the trimming themselves. Adams requests that the Commission require PG&E to cease its current practice of charging customers for trimming around service drops.

PG&E responds that the responsibility for maintaining services[71] or service wire is clearly set forth in Electric Rule 16 of PG&E's tariffs, which requires customers to maintain clearance around services. PG&E maintains that Adams' request would require changes to the Commission's General Order 95 as well as Electric Rule 16, subjects that are currently part of R.01-10-001, the Commission's ongoing Rulemaking considering revisions to GO 95 and GO 128.

10.5.1 Discussion

The Commission's General Order 95 applies to owners of electrical systems and sets forth rules regarding overhead electric line construction, maintenance, and safety. Included among the rules in GO 95 is Rule 35, which addresses tree clearance requirements and responsibilities. As PG&E correctly notes, Adams' request would require a change to Rule 35 of GO 95.

While we understand and appreciate Adams' concern for the safety of PG&E's customers, Adams request would require changes to GO 95 and Electric Rule 16, issues that Adams admits are the subject of another ongoing proceeding. We do not adopt Adams' recommendations.

10.6 Adopted Rate Changes

In its application, PG&E stated that it was not seeking a change in total electric rates for the increased revenue requirement it was requesting due to the fact that bundled electric rates remained "frozen." PG&E stated that although electric rates were not expected to increase immediately if the Commission approved its forecast, future electric rates may be affected. As noted above,

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[71] As defined by PG&E, "services" are the overhead wires that run from the low voltage connection on the distribution transformer to the customer's weatherhead

Footnote continued on next page

D.04-02-062 adopted a Rate Design Settlement implementing, on an interim basis, rate reductions contemplated in D.03-12-035, the Commission's Decision approving a Modified Settlement Agreement in PG&E's bankruptcy proceeding. D.04-02-062 provides that the final resolution of rate design issues related to the Modified Settlement Agreement will be litigated in Phase 2 of PG&E's GRC (the instant proceeding).[72] The rate reductions provided in the Rate Design Settlement were based, on applicant's "best estimates of its revenue requirements" (D.04-02-063, p. 12), including, in part, on an assumption that the Settlements filed in this proceeding would be approved and that applicant's requested contribution to the Retirement Plan trust would be granted. Therefore, the increase in PG&E's revenue requirements for electric distribution we authorize today has already been reflected, and to a large degree, offset, as part of the revenue requirement reductions approved in D.04-02-062, resulting in minimum changes to current electric rates.

D.04-02-062 provides that with a final decision in Phase 1 of the GRC, PG&E shall revise component revenue requirements for Nuclear Decommissioning, Public Purpose Programs, Distribution, and non-fuel Retained Generation. (D.04-02-062, p. 12.) D.04-02-062 also directs PG&E to implement an approximate $18 million annual revenue requirement increase for Direct Access customers and prepare associated billing changes which were

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and/or meter.

[72] D.04-02-062 provided for a final resolution of certain issues that would otherwise have been litigated in Phase 2. (*See* D.04-02-062.)

deferred in D.04-02-062 until the final Phase 1 decision. (D.04-02-062, Conclusion of Law 4.)

D.04-02-062 authorizes PG&E to adjust its electric and distribution rates as follows:

> "In the event that additional rate changes are needed prior to the adoption of rates in Phase 2 of PG&E's 2003 GRC due to changes in PG&E's total revenue requirement, such as would occur if FERC refunds or El Paso settlement refunds are received, such additional interim changes will be implemented based on the following principles: Changes in the revenue requirement for any given component will be recovered as an equal percent change to the component that is changing. For example, if the distribution revenue requirement decreases relative to the revenue at then-current distribution rates, PG&E would lower all distribution rate components by the percent required to achieve the necessary reduction. Total rates would then be reduced commensurately. Similarly, if the generation revenue requirement increases, generation rates for all bundled service customers would be increased on a system average percentage basis and total rates would increase commensurately. The DA CRS cap shall not be modified solely as a result of such interim revenue requirement changes, but accruals of CRS cap undercollections may be affected, consistent with existing Commission policies and this Agreement." (D.04-02-063, Attachment A, Section 10, p. 5.)

Consistent with the Commission's decision in the Gas Accord, prior gas cost allocation proceedings, and the Rate Case Plan, gas rate design for the gas distribution revenue requirement is determined in PG&E's BCAP. Therefore, the gas revenue requirement adopted herein will be allocated to customer classes according to PG&E's most recent BCAP.

10.7 Rulings of the Administrative Law Judge

The rulings of the ALJ regarding admissibility of evidence, access to computer models, status as an intervenor, and status regarding intervenor compensation are affirmed.

Comments on Proposed Decision

The ALJ's proposed decision was issued pursuant to Pub. Util. Code § 311(d). Pursuant to Article 19 of the Rules of Practice and Procedure, parties were permitted to review and comment on the proposed decision.

Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Julie M. Halligan is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. On July 31, 2003, after conclusion of evidentiary hearings, Pacific Gas and Electric Company (PG&E), ORA, TURN, Aglet, CCSF filed a joint motion for a Settlement Agreement resolving disputed issues related to PG&E's TY 2003 generation revenue requirement request.

2. On September 15, 2003, PG&E, ORA, TURN, Aglet, MID, NRDC, and AECA filed a joint motion for a Settlement Agreement resolving all but one of the disputed issues related to PG&E's forecast TY 2003 electric and gas distribution and generation revenue requirements.

3. The Commission reviews the Distribution Settlement and the Generation Settlement pursuant to Rule 51.1(e) of the Commission's Rules of Practice and Procedure, which provides that the Commission must find a settlement reasonable in light of the whole record, consistent with the law, and in the public interest.

4. The Settling Parties represent all parties who contested or otherwise expressed an interest in the issues subject to the Settlements.

5. The Settlements represent a compromise of the strongly-held views of the sponsoring parties.

6. The Settling Parties fairly reflect the affected interests in this proceeding.

7. An attrition rate adjustment adjusts some elements of the utility's cost of service during the course of the rate case cycle to account for inflation.

8. The ARA mechanism was designed to provide utilities with the reasonable opportunity of achieving their authorized rates of return during years in which they are not permitted under the Commission's rate case plan procedures to file for general rate relief but in which they still face volatile economic conditions.

9. The record supports the Settling Parties agreement to grant attrition adjustments for the years 2004, 2005, and 2006 tied to the level of inflation, as measured by CPI-All-Urban Consumers, to provide PG&E the opportunity to earn its authorized rate of return in the attrition years.

10. The record supports an additional 1% adder to the CPI-based attrition adjustment for the third attrition year, 2006, to reflect the difficulty of forecasting expenses for a third attrition year.

11. The record does not support a finding that a minimum attrition adjustment is necessary for years 2004, 2005, and 2006, regardless of the level of inflation.

12. A minimum attrition adjustment is inconsistent with the Commission's attrition policy.

13. Allowance of a minimum attrition adjustment regardless of the level of inflation is unreasonable.

14. Section 5.3 of the Distribution Settlement is unreasonable and not in the public interest because it would provide for a minimum attrition adjustment irrespective of the rate of inflation.

15. Sections 9 and 10 of the Generation Settlement are unreasonable and not in the public interest because they provide for a minimum attrition adjustment irrespective of the rate of inflation.

16. As modified to remove the minimum attrition adjustment, the Settlements are fair, just and in the public interest.

17. With the modification to eliminate the minimum attrition adjustment, no term of the Settlements contravenes statutory provisions or prior Commission decisions.

18. The need for ratepayer contributions to the Retirement Plan trust should be determined based on the funding status of the Retirement Plan trust.

19. PG&E has not provided sufficient evidence demonstrating that its requested $128.6 million contribution to the Retirement Plan trust is necessary.

20. In the absence of clear and convincing evidence that a contribution of $128.6 (total company) million is needed, it is unreasonable to adopt PG&E's request for a $128.6 million contribution to the Retirement Plan Trust.

21. On November 29, 2001, Mothers for Peace filed its Petition to Modify D.88-12-083.

22. Attachment A of Appendix C to D.88-12-083 contains all the pertinent details regarding the composition and operations of the Diablo Canyon Independent Safety Committee (DCISC).

23. The Stipulation resolving certain issues associated with the Diablo Canyon Independent Safety Committee (DCISC) is in the public interest because it provides for a mutually acceptable outcome to the issue of whether the DCISC should continue to exist and no party opposes it.

24. The petition fails to provide any evidence that the DCISC members or their consultants have any conflict of interest, or that the nomination and appointment process has resulted in biased committee members.

25. Mothers for Peace's proposed change to the nominating procedures for establishing the composition of the DCISC is a reasonable improvement to the existing process because it would both streamline the process and remove any perceived conflict of interest.

26. Modifying the DCISC nomination process in response to a reasonable request is an appropriate exercise of our oversight responsibilities with respect to the operation of Diablo Canyon.

27. The experience requirements for individuals serving on the DCISC should reflect the stated purpose for which the DCISC was created – assessing the safety and operations and suggesting any recommendations for safe operations.

28. DCISC nominees should be required to have knowledge, background and experience in the field of nuclear power facilities and nuclear safety issues.

29. There is nothing to prevent a resident of the San Luis Obispo area, with the requisite background and experience in nuclear issues, from seeking nomination and appointment to the DCISC.

30. As reflected by the record in this case, the public meetings it holds in the San Luis Obispo area, the annual reports that it prepares, the recommendations that it makes to PG&E, and other activities of the committee member, the DCISC has been actively fulfilling its duties.

31. In the absence of any evidence that DCISC's compensation or funding has not been used to promote an additional assurance of safety at Diablo Canyon, Mothers for Peace's request for an investigation into the use of ratepayer funds for the DCISC is not necessary.

32. An office in San Luis Obispo would make the DCISC more accessible to the residents of the area surrounding Diablo Canyon.

33. Since it is not clear whether the work scope of the DCISC as established in D.88-12-083, was intended as a full-time operation, the issue of whether or not to establish a full-time office should be left to the discretion of the DCISC.

34. Requiring PG&E to continue funding the videotaping for DCISC meeting is a low-cost and efficient method of providing information to the public on Diablo Canyon and the DCISC, especially for members of the public who cannot attend meetings.

35. Based on the results of the Towers Perrin Total Compensation Study, PG&E's TY 2003 forecast request for executive compensation is either at or slightly below market levels.

36. The Towers Perrin Total Compensation Study evaluates total compensation, defined as the combination of cash compensation (base salary plus short-term incentives[73]) and benefits (medical, dental, vision, life insurance, disability, pension, and savings plans).

37. The Commission's policy does not allow funding for philanthropic contributions in regulated utility rates.

38. Greenlining's request that the Commission encourage PG&E to link executive compensation to philanthropic contributions, workforce diversity, or supplier diversity is not adequately supported by the evidence.

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[73] For PG&E, short-term incentives are represented by the Performance Incentive Plan and are calculated based on a target incentive award of 50 percent of the maximum potential payout.

39. Requiring PG&E to justify increases in compensation above the labor escalator in the next GRC will provide the Commission with additional information on which to consider compensation requests.

40. TURN's request that PG&E be required to justify increases in compensation above the labor escalator with evidence beyond that provided by market comparison studies is reasonable because it will allow the Commission to effectively evaluate the potential "wage creep" arguments associated with total compensation studies.

41. In January 2004, PG&E Corporation awarded $84.5 million in retention bonuses to 17 key executives pursuant to the SrERP.

42. None of the $84.5 million in SrERP awards has been charged to ratepayers.

43. Adopted TY 2003 rates do not include any amounts for retention programs, and program costs are not included in the regulatory asset or calculation of headroom.

44. PG&E Corporation shareholders have funded, and will fund, the entire $84.5 million in SrERP awards.

45. Many members of society are frustrated with corporate executives taking excessive compensation.

46. The goal of the SrERP bonuses was to retain top officers during a difficult period, linking retention to time and performance.

47. Between 1992 and 2002, PG&E's workforce diversity has increased in all but one category of PG&E's workforce.

48. PG&E has in place formal, effective programs designed to increase workforce diversity.

49. Greenlining has not demonstrated that an additional annual report of diversity statistics is necessary or preferable to our current approach of reviewing workforce diversity statistics as part of the utility's GRC.

50. The revenue requirements set forth in Attachment D to this decision are reasonable.

Conclusions of Law

1. As modified, the Settlements are in the public interest, consistent with the law, and should be approved.

2. The Motion to Adopt a Stipulation (Stipulation) filed by PG&E, DCISC, ORA, Mothers for Peace, California Energy Commission (CEC) and TURN regarding the DCISC is in the public interest and should be granted.

3. The Stipulation between PG&E, DCISC, ORA, Mothers for Peace, CEC and TURN filed a under which the DCISC would continue to exist and be funded through cost-of-service rates at least through the next rate case cycle should be approved.

4. Mothers for Peace's revised petition to modify D.88-12-083 should be addressed in this proceeding.

5. The DCISC should retain the discretion to determine how best to accomplish its mandate.

6. Greenlining's proposal to link executive compensation to philanthropic contributions should not be adopted.

7. We have no basis upon which to address the level of PG&E's philanthropic contributions.

8. Additional accounting and reporting measures should be adopted to ensure that the $84.5 million is charged to shareholders, not ratepayers.

9. Even though about $973,000 in SrERP accruals booked to Account 923 in 2001 and 2002 did not affect rates, PG&E should adjust these amounts to ensure "below-the-line" treatment.

10. Consistent with our expectations and orders regarding retention bonuses, the $84.5 million of SrERP expenses in general—and the $53.2 million charged to PG&E in particular—should be, and are, ineligible for recovery from ratepayers via existing rates, the TY 2003 revenue requirement, TY 2003 rates, headroom, the regulatory asset, or any other ratemaking tools or rates that involve ratepayer funds.

11. PG&E's advice letter filing to demonstrate compliance with Ordering Paragraph 4 of D.03-12-035 should also (a) show the adjustments from Account 923 of about $973,000, (b) show the accounting of all SrERP payments (including those made in January 2004, whether or not the cash distributions were deferred) to demonstrate that they were not charged to ratepayers, and (c) include anything else reasonably necessary to ensure that ratepayers have not paid, and will not pay, any portion of the $84.5 million in SrERP expenses.

12. PG&E and PG&E Corporation should fully cooperate with a Commission staff audit of the accounting and treatment of the $84.5 million in SrERP expenses.

13. PG&E should list all SrERP awards in its 2003 GO 77-K Report and indicate the FERC account to which the payment will be billed, with PG&E providing that information in a separate table listing only SrERP recipients to the extent necessary to clearly identify the persons, amounts and FERC account.

14. PG&E should file an advice letter within 10 days of the date that PG&E Corporation announces that it will reinstate the payment of dividends and knows its total earnings and dividend rate to show the retained earnings (total and per share) before and after the award of the $84.5 million SrERP, and the effect, if any, on dividends (total and per share), with the $84.5 million applied in the same period as the earnings and dividends.

15. PG&E should file a report with the Commission within 90 days after its next annual shareholders meeting that states whether or not any or all officers returned some or all of their retention bonus awards, and identifies the specific individuals and amounts returned, if any.

16. In order to verify that the Senior Executive Retention Bonus program was not paid for by ratepayers, the Commission's Energy Division should conduct an audit of the accounting transactions related to this program.

17. In its next GRC, PG&E should provide an update of its workforce diversity statistics.

O R D E R

IT IS ORDERED that:

1. The Joint Motion of Pacific Gas and Electric Company (PG&E), Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), Aglet Consumer Alliance (Aglet), Modesto Irrigation District (MID), Natural Resources Defense Council (NRDC), and the Agricultural Energy Consumers Association (AECA) for Approval of a Settlement Agreement, filed on September 15, 2003, and as forth in Attachment A, is granted. The Settlement Agreement, as modified to eliminate the minimum attrition adjustment, is approved. .

2. The Settlement Agreement shall be construed as leaving intact all policy determinations adopted in D.00-02-046.

3. The Motion of PG&E, ORA, TURN, the City and County of San Francisco, and Aglet for Approval of a Settlement Agreement, filed on July 31, 2003, and as set forth in Attachment B, is granted.

4. The Settlement Agreement sponsored by PG&E, ORA, TURN, Aglet, MID, and NRDC, and attached to the opinion as Appendix B is adopted, subject to the modification discussed in this opinion.

5. PG&E shall, within 10 days of this effective date of this order, file revised tariff sheets to implement the revenue requirements, accounting procedures, and charges set forth in this decision.

6. Subject to verification of compliance by the Energy Division, the revised tariff pages shall become effective on January 1, 2003.

7. PG&E is authorized to adjust its rates pursuant to D.04-02-062 and this order. PG&E is authorized to consolidate rate changes authorized here with any rate changes authorized in the Commission's decision on the Storm and Reliability phase of this proceeding.

8. PG&E is authorized to increase its NSF fees to $8.00.

9. The Motion of PG&E, Diablo Canyon Independent Safety Committee (DCISC), ORA, TURN, the California Energy Commission (CEC), and Mothers for Peace to Adopt a Stipulation is granted, and the Stipulation as set forth in Attachment C to this decision, is approved.

10. Mothers for Peace's Petition to Modify D.88-12-083 is granted in part and denied in part as discussed in Section 10.2 of this decision.

11. The following accounting and reporting measures are adopted to ensure that the $84.5 million in Senior Executive Retention Program (SrERP) awards were not, are not, and will not be charged to ratepayers.

a. PG&E shall file and serve an advice letter regarding compliance with Ordering Paragraph 4 of D.03-12-035. The advice letter shall also show:

i. Adjustments to Account 923 for 2001 and 2002 to reverse accruals for the SrERP;

ii. The accounting of all SrERP payments, including those made in January 2004 (even if cash distributions were deferred), to demonstrate that the payments were and are not charged to ratepayers; and

iii. Anything else reasonably necessary to ensure that ratepayers have not paid, and will not pay, any portion of the $84.5 million in SrERP expenses.

b. If the advice letter has already been filed, PG&E shall file and serve a supplemental advice letter within 10 days of the mailing date of this order to include this additional information. The Executive Director shall direct Commission staff to audit the accounting and treatment of the $84.5 million as reported in the advice letter or supplemental advice letter. PG&E and PG&E Corporation shall fully cooperate with the Commission staff audit.

c. PG&E shall list all SrERP awards in its 2003 General Order (GO) 77-K Report and indicate the Federal Energy Regulatory Commission (FERC) account to which the payment was or will be billed. If applicant's 2003 GO 77-K Report (as filed by March 31, 2004) did not include a list of the $84.5 million retention bonus awards and show the FERC account to which they were or will be charged, applicant shall provide that information by filing an amendment to its 2003 GO 77-K Report within 10 days of the mailing date of this decision. Further, if the 2003 GO 77-K report did not clearly identify the persons, retention bonus amounts and FERC account, PG&E shall provide that information in a separate table that lists only SrERP recipients by the filing an amendment to its 2003 GO 77-K Report within 10 days of the mailing date of this decision.

d. PG&E shall file and serve an advice letter within 10 days of the date that PG&E Corporation announces that it will reinstate the payment of dividends and knows its total earnings and dividend rate. The advice letter shall show retained earnings (total and per share) before and after the award of the $84.5 million in SrERP bonuses, and the effect, if any, on dividends (total and per share). If the earnings, payment of dividends and the charges for the $84.5 millionaire not in the same period, the advice letter shall apply the $84.5 million in the same period covered by the earnings and dividends. PG&E shall serve a copy of the advice letter or a notice of availability on the service list for Phase 1 of this proceeding.

12. G&E shall file a test year 2007 general rate case applications in accordance with the Rate Case Plan.

This order is effective today.

Dated ____________________, at San Francisco, California.

ATTACHMENT A

ATTACHMENT B

ATTACHMENT C

ATTACHMENT D

ATTACHMENT E
LIST OF APPEARANCES

Halligan Comment Dec Attachment A-E Opinion Phase 1 Issues