Decision 07-03-044 March 15, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39-M) for Authorization, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007.	Application 05-12-002 (Filed December 2, 2005)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service, and Facilities of Pacific Gas and Electric Company (U 39-M).	Investigation 06-03-003 (Filed March 2, 2006)

(*See* Appendix A for a List of Appearances.)

OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

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OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2007 - 2010

I. Summary

This Opinion adopts a Settlement Agreement that resolves most issues arising from Pacific Gas and Electric Company's (PG&E) general rate case Application (A.) 05-12-002. The adopted Settlement Agreement increases PG&E's revenue requirement for Gas Distribution, Electric Distribution, and Generation by $213 million in 2007 and by $125 million annually during 2008, 2009, and 2010. PG&E is also allowed to recover an additional $35 million for a refueling outage at the Diablo Canyon nuclear power plant. Compared to the preceding year, this Opinion authorizes an increase in PG&E's general rate case (GRC) revenue requirement of 4.5% in 2007, 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The increase in PG&E's overall revenue requirement is 1.4% in 2007, 0.8% in 2008, 1.0% in 2009, and 0.6% in 2010.

The other elements of the adopted Settlement Agreement include the following:

- The addition of a third attrition year, 2010, which shifts PG&E's next GRC to test-year 2011.
- A provision that keeps all 84 of PG&E's front counters open pending further developments in Phase 2 of this proceeding regarding PG&E's proposal to close its front counters.
- A Bill-Calculation Service for mobile home park owners with sub-metered tenants.
- A memorandum of understanding between PG&E and the Disability Rights Advocates (DIRA) wherein PG&E agrees to take certain measures to improve its operations affecting disabled persons.

The increased revenue requirement authorized by this Opinion is effective on January 1, 2007, pursuant to Decision (D.) 06-10-033. This revenue requirement is in addition to increases previously authorized in this proceeding for pensions costs in the amounts of $98 million for 2007, $102 million for 2008, $106 million for 2009, and $111 million for 2010.[1]

There are additional elements of today's Opinion that consist of accounting and reporting requirements. These include a requirement for PG&E to record a regulatory liability for $2.1 billion that PG&E has collected in rates but not yet spent to retire and remove assets from service.

The Settlement Agreement does not address issues raised by the Greenlining Institute (Greenlining). These issues focused on executive pay, supplier diversity, employee diversity, and corporate philanthropy. The issues raised by Greenlining are addressed separately. Greenlining and PG&E were able to resolve these issues, and their accord is adopted by today's Opinion.

This proceeding remains open to consider issues associated with PG&E's request to close many of its customer-service counters.

II. Procedural Background and Chronology

PG&E filed A.05-12-002 on December 2, 2005. In A.05-12-002, PG&E requested, among other things, authority to increase its GRC revenue requirement to $5.238 billion effective January 1, 2007, for Gas Distribution, Electric Distribution, and Electric Generation. Compared to 2006, the requested

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[1] These are estimated pension costs. The actual revenue requirement for pension costs will vary depending on several factors. See D.06-06-014 for an explanation of the variance.

GRC revenue requirement for 2007 represented an increase of $524 million, or 11.1%. PG&E requested additional increases in 2008 and 2009.

A prehearing conference (PHC) was held on January 23, 2006. Assigned Commissioner Bohn issued a Ruling and Scoping Memo (ACR) on February 3, 2006, that established the scope and schedule for the proceeding. The ACR called for hearings to begin in May 2006 and a final decision in December 2006 on all issues except PG&E's proposed Performance Incentive Mechanism.

On March 2, 2006, the Commission issued Order Instituting Investigation (I.) 06-03-003, the companion investigation to this GRC. The purpose of I.06-03-003, which was consolidated with A.05-12-002, was to allow the Commission to (1) address matters raised by parties other than PG&E, and (2) issue orders on matters for which PG&E might not be the proponent.

In a related proceeding, A.05-12-021, PG&E requested recovery of contributions made to its employee pension plan in 2006. Granting A.05-12-021 would reduce PG&E's revenue requirement for pension costs in this GRC proceeding. On March 8, 2006, PG&E, the Commission's Division of Ratepayer Advocates (DRA), and the Coalition of California Utility Employees (CCUE) filed a settlement agreement that resolved all issues in A.05-12-021 and all pension-cost issues in this GRC proceeding. Among other things, the settlement allowed PG&E to recover the following GRC revenue requirement for pension costs: $155 million in 2006, $98.2 million in 2007, $101.7 million in 2008, and $106.1 million in 2009. The Commission adopted the uncontested settlement agreement in D.06-06-014.

DRA served its written testimony on GRC issues on April 14, 2006. The following parties served their written testimony on April 28, 2006: the Modesto Irrigation District (Modesto ID), the Merced Irrigation District (Merced ID), the

South San Joaquin Irrigation District (SSJID), DIRA, Aglet Consumer Alliance (Aglet), The Utility Reform Network (TURN), Greenlining, and others. The following parties served rebuttal testimony on May 17, 2006: PG&E, Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), and Southern California Gas Company (SCG).

Ten public participation hearings (PPHs) were held at various locations in PG&E's service territory during April and May, 2006.[2] Hundreds of letters were also received from the public.

On May 30, 2006, the assigned Administrative Law Judge (ALJ) granted the joint motion of PG&E, DRA, and several intervenors to defer to early 2007 PG&E's proposal to close all of its front counters where customers can obtain help, information, and services. A noticed settlement conference regarding PG&E' proposal was held on February 15, 2007.

On May 31, 2006, the ALJ ruled that all issues associated with PG&E's proposed late-payment fee would be removed from this proceeding and considered, as appropriate, in I.03-01-012.[3]

A second PHC was held on May 25, 2006. Twenty-five days of evidentiary hearings were held between May 31 and July 7, 2007. During the evidentiary hearings, the ALJ admitted into the record the written testimony of 118 witnesses and approximately 157 other hearing room exhibits.

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[2] The PPHs were held at the following locations: Oakland, Ukiah, Santa Rosa, King City, Salinas, San Louis Obispo, Modesto, Fresno, Woodland, and Chico.

[3] I.03-01-012 is the companion investigation to PG&E's previous GRC proceeding, A.02-11-017.

After the conclusion of hearings, PG&E's requested revenue requirement for 2007 stood at $5.109 billion. The decrease from the initial amount in the A.05-12-002 was due to (1) PG&E's concessions on several issues raised by DRA, Aglet, and TURN, and (2) the resolution of pension-cost issues by D.06-06-014. PG&E's revised request for 2007 represented an increase of $395 million, or 8.38%, over its 2006 authorized revenue requirement. By comparison, DRA recommended $4.734 billion for 2007, or $375 million less than PG&E's request.

On August 16, 2006, PG&E and several parties held a noticed settlement conference to discuss a proposed settlement. On August 21, 2006, PG&E and most of the active parties jointly filed a settlement agreement[4] and a motion to adopt the settlement agreement.[5] The Settlement Agreement purports to resolve all issues except those raised by Greenlining. The parties joining in the Settlement Agreement are PG&E, DRA, Modesto ID, Merced ID, SSJID, DIRA, the Western Manufactured Housing Communities Association (WMA),

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4 Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees. This document is referred to hereafter as "the Settlement Agreement" or "the Settlement."

5 Motion of Pacific Gas and Electric Company, Division of Ratepayer Advocates, The Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Irrigation District, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Federation, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees For Approval of Settlement Agreement. This document is referred to hereafter as the "Settlement Motion." The Settlement Agreement was attached to the Settlement Motion.

California Farm Bureau Federation (CFBF), SCE, SDG&E, SCG, and CCUE (together, the Settling Parties). Most of the Settling Parties join only in certain paragraphs of the Settlement Agreement that resolve the particular issues raised by these Parties.[6] A copy of the Settlement Agreement is in Appendix C of today's Opinion.

Noticed technical conferences regarding the Settlement Agreement were held on August 23 and September 6, 2006. PG&E also responded to several written data requests regarding the Settlement Agreement.

The Settlement Agreement is opposed by Aglet, the Alliance for Nuclear Responsibility and the Sierra Club (ANR/SC), and TURN. Rule 12.2 of the Commission's Rules of Practice and Procedure (Rule 12.2) governs comments filed by parties who contest a settlement agreement. Rule 12.2 states:

> Comments must specify the portions of the settlement that the party opposes, the legal basis of its opposition, and the factual issues that it contests. If the contesting party asserts that hearing is required by law, the party shall provide appropriate citation and specify the material contested facts that would require a hearing. Any failure by a party to file comments constitutes waiver by that party of all objections to the settlement, including the right to hearing.

Comments opposing the Settlement were filed on September 20, 2006, by Aglet, ANR/SC, and TURN. None of these parties requested an evidentiary

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6 Settlement Motion, p. 2, Fn. 1. Modesto ID joins only in paragraphs 1, 2, 3, 10, 11, 19, 49, and 50 of the Settlement. Merced ID joins only in paragraphs 1, 2, 3, 10, 11, 19, and 50. SSJID joins only in paragraphs 1, 2, 3, 10, and 19. DIRA joins only in paragraphs 1, 2, 3, 13A, and 48. WMA joins only in paragraphs 1, 2, 3, 12, and 25. CFBF joins only in paragraphs 1, 2, 3, 13B, and 24. SCE, SDG&E, and SoCalGas join only in paragraphs 1, 2, 3, 13C, and 41. (*See* Settlement, para. 3, conditions M-S.)

hearing on the Settlement.[7] Three sets of reply comments were filed on October 5, 2006, by (1) SCE, (2) jointly by SDG&E and SCG, and (3) jointly by the Settling Parties other than SCE, SDG&E, and SCG.

As noted earlier, the Settlement Agreement does not resolve issues raised by Greenlining. These issues – which include executive compensation, supplier diversity, employee diversity, and corporate philanthropy – were the subject of separate briefs. PG&E was the only party to respond to the issues raised by Greenlining. Greenlining filed an opening brief on August 7, 2006. PG&E filed a reply brief on August 21, 2006. Greenlining filed a closing brief on August 28, 2008. PG&E and Greenlining resolved these issues at the last minute in their comments on the Alternate Proposed Decision.

The ACR issued on February 3, 2006, set a schedule that provided for the issuance of a final decision regarding most GRC issues in December 2006. This schedule was extended in several ALJ rulings in order to provide time for the parties to reach a settlement. On August 11, 2006, PG&E filed a motion for the Commission to issue an interim decision that makes PG&E's GRC revenue requirement for the 2007 test year adopted in this proceeding effective on January 1, 2007, in the event the Commission issues a final decision adopting PG&E's GRC revenue requirement after that date. The Commission granted PG&E's unopposed motion in D.06-10-033. As a result, the 2007 GRC revenue requirement authorized by today's Opinion is effective as of January 1, 2007.

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7 Greenlining's informal request for an evidentiary hearing was denied by the assigned ALJ in a ruling issued on October 6, 2006.

Greenlining and Aglet submitted timely requests pursuant to Rule 13.13(b) for an oral argument before a quorum of the Commission. The oral argument was held on March 2, 2007.

In the remainder of today's Opinion, we will first evaluate the Settlement Agreement and the opposition to the Settlement. We will then address the issues raised by Greenlining.

III. Summary of the Settlement Agreement

The Settlement Agreement purports to resolve all issues in this proceeding except those issues raised by Greenlining. The resolved issues include those raised by Aglet, ANR/SC, and TURN, who are not parties to the Settlement.

The Settlement Agreement adopts a GRC revenue requirement of $4.927 billion in 2007.[8] The following table compares the Settlement revenue requirement with the litigation positions of PG&E and DRA:

[8] The revenue requirement adopted by the Settlement Agreement excludes costs that are (i) regulated by the Federal Energy Regulatory Commission (FERC), and (ii) the subject of other Commission proceedings, including replacement of PG&E's Diablo Canyon steam generators, the Contra Costa 8 generating facility, and Advanced Metering Infrastructure. The Settling Parties agree that under the Settlement there is no double recovery of costs in this GRC and other proceedings.

2007 GRC Revenue Requirement ($ millions)							
		Comparison Exhibit		**Settlement**			
	2006 Authorized	**PG&E**	**DRA**	**Settlement**	**Settlmt. vs. 2006**	**Settlmt. vs. PG&E**	**Settlmt. vs. DRA**
Electric Distrib.	2,648	2,991	2,809	**2,870**	222	(121)	61
Gas Distrib.	1,027	1,062	1,001	**1,047**	21	(15)	46
Generation	1,039	1,056	924	**1,010**	(30)	(46)	86
Total	**4,714**	**5,109**	**4,734**	**4,927**	**213**	**(182)**	**193**
Source: Settlement, Appendix B.							

The GRC revenue requirement adopted by the Settlement for 2007 represents an increase of $213 million, or 4.5%, compared to 2006. On a total system basis, the Settlement increases PG&E's billed revenues by 1.4% in 2007.

The Settlement Agreement adds a third attrition year – 2010 – to the GRC cycle. The Settlement provides for annual attrition increases of $125 million in 2008, 2009, and 2010, and an additional $35 million in 2009 for a refueling outage at Diablo Canyon. The following table compares the Settlement outcome for attrition to PG&E's and DRA's litigation positions:

2008 – 2010 Attrition GRC Revenue Requirement ($ millions)					
	PG&E	**DRA**	**Settlement**	**Settlement vs. PG&E**	**Settlement vs. DRA**
2008	143	100	125	(18)	25
2009	180	131	125	(55)	4
2010	--	--	125	--	--
2009 Diablo Canyon Refueling			35	--	--
Source: Settlement, Appendix E.					

Compared to the immediately preceding year, the Settlement increases PG&E's GRC revenues by 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010. The compound percentage increase over 2007 - 2010 is 12.46%. The above tables show that the Settlement provides PG&E with approximately $634 million less than it requested in cumulative revenues for 2007, 2008, and 2009.[9]

As noted previously, the Settlement divides the GRC revenue requirement among Gas Distribution, Electric Distribution, and Electric Generation. The Settlement further divides the revenue requirement into numerous areas. Some of the specific dollar amounts for 2007 are as follows:

- Operations and maintenance (O&M) expense - $1.079 billion.
- Depreciation expense - $942 million.
- Total Company administrative and general (A&G) expense - $772 million.
- Customer services expense - $431 million.
- Net weighted capital additions - $453 million.
- Rate Base - $12.6 billion.
- Fossil decommissioning refund - $26.8 million.
- Other operating revenues - $116 million.

The Settlement resolves numerous issues that are not expressed in dollar terms. These issues include:

- Forecasts of customers, sales, and revenues at present rates.
- Continuation of the one-way Vegetation Management Balancing Account, and a new Vegetation Management tracking account.
- Uncollectibles factor.
- Various customer fees.

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9 $634 million = (3 x 182 million) + (2 x 18 million) + $55 million.

- Continued operation of all front counters pending further litigation and possible settlement of PG&E's proposal to close its front counters.
- Billing services for mobile home parks.
- Direct access fees.
- Replacement of the Company airplane.
- Capitalization rates.
- A&G allocations to non-GRC operations.
- Franchise fee factor.
- Memorandum of Understanding between DIRA and PG&E.
- O&M labor factors.
- Results of operations model.
- Withdrawal of PG&E's proposed Earnings-Sharing Mechanism.
- Withdrawal of PG&E's proposed Performance-Incentive Mechanism.

The Settling Parties request that the Commission approve the Settlement Agreement without modification and find that the Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

IV. Standard of Review

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[10] Although the Commission favors the settlement of disputes, Rule 12.2 provides that the Commission 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.

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10 D.05-03-022, *mimeo.*, pp. 7-8.

The Settlement Agreement is opposed by Aglet, ANR/SC, and TURN. The Commission's policy is that contested settlements should be subject to more scrutiny compared to an all-party settlement.[11] As explained in D.02-01-041:

> In judging the reasonableness of a proposed settlement, we have sometimes inclined to find reasonable a settlement that has the unanimous support of all active parties in the proceeding. In contrast, a contested settlement is not entitled to any greater weight or deference merely by virtue of its label as a settlement; it is merely the joint position of the sponsoring parties, and its reasonableness must be thoroughly demonstrated by the record. (D.02-01-041, *mimeo*., p. 13.)

For the preceding reasons, we will review the Settlement's resolution of every contested issue, with careful consideration given to each issue raised by Aglet, ANR/SC, and TURN. The purpose of our issue-by-issue review is not to second guess the Settlement outcome for every individual issue, but to assess whether the Settlement as a whole is reasonable in light of the entire record, consistent with applicable law, and in the public interest.

V. Review of the Settlement Agreement

A. Customer Services

PG&E's Customer Services organization consists of the processes, technology, and people that together link PG&E with its 5 million electric customers and 4.1 million gas customers. PG&E requested $437.7 million for Customer Services expenses in 2007. PG&E also requested increases in several

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11 D.96-01-011, Finding of Fact (FOF) 5. See D.96-01-011, 1996 Cal. PUC LEXIS 23, 39, 40 ("This more detailed review and heightened scrutiny is especially appropriate when the settlement is not all-party.").

fees and its uncollectibles factor. DRA, Aglet, TURN, and others opposed certain aspects of PG&E's request.

The Settlement adopts $431 million for Customer Services expenses in 2007, which is $7 million less than PG&E requested. The following table compares the Settlement outcome with PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Customer Services Expenses ($ millions)							
		Comparison Exhibit		Settlement			
	2006 Authorized	PG&E	DRA	Settlement	Settlmt. vs. 2006	Settlmt. vs. PG&E	Settlmt. vs. DRA
Electric Distrib.	186.6	187.0	180.3	184.3	(2.3)	(3.7)	4.3
Gas Distrib.	237.6	250.7	245.1	246.8	9.2	(3.9)	1.7
Total	424.2	437.7	425.4	431.1	6.9	(6.6)	5.7
Source: Settlement Agreement, Appendix B, Lines 2, 12, and 28.							

The Settling Parties agree that capital expenditures for Customer Services is subsumed within the capital expenditures adopted by the Settlement for Electric Distribution, Gas Distribution, and Common Plant, which are addressed elsewhere in today's Opinion. The Settling Parties also reached the following agreements on other Customer Services issues:

- PG&E will keep its front counters open pending a resolution of this issue either through settlement or Commission decision. (Settlement, para. 24.)
- PG&E will implement billing services for mobile home park owners with sub-metered tenants. (Settlement, para. 25.)
- Direct access service fees will remain at their current level (Settlement, para. 26.)
- The uncollectibles factor will be 0.002586. (Settlement, para. 20.)

- The "restoration for non-payment" fee will be increased from $20.00 during regular business hours and $30.00 during non-business hours to $25.00 and $37.50, respectively. CARE customers are exempted from the increase. (Settlement, para. 22.)
- The non-sufficient funds (NSF) fee will be increased from $8.00 to $11.50. (Settlement, para. 21.)
- PG&E will implement a new service quality standard that pays $100 to customers whose service is improperly shut off. (Settlement, para. 23.)

Below, we assess the reasonableness of the Settlement outcome for Customer Services in light of the record on the issues raised by DRA and others.

1. Front Counters

a. Position of the Parties

PG&E operates 84 "front counters" where customers can establish service, pay bills, and obtain a variety of utility services and information. About 40% of the front counters are located in PG&E service centers, which are used primarily for field service operations. The remainder of the front counters are located in office space either owned by PG&E or leased from others.

In A.05-12-002, PG&E proposed to close all 84 front counters by June 30, 2007, and to transfer many of the functions to pay stations operated by third parties. Closing the front counters would reduce PG&E's revenue requirement by $24 million annually starting in 2008. If the Commission does not approve PG&E's proposal, PG&E requested $37.1 million in expenses for front counters in 2007 and $0.15 million for capital expenditures in 2007.

Several parties opposed PG&E's proposal to close its front counters (i.e., DRA, TURN, and CFBF). The only party to contest PG&E's expense request for continued operations was TURN, who argued for a 20% reduction of PG&E's requested expenses. No party contested the requested capital expenditures.

On May 26, 2006, the active parties for front counter issues submitted a joint motion seeking to defer to Phase 2 of this proceeding all issues regarding PG&E's proposal to close its front counters. The unopposed motion was granted by an ALJ ruling issued on May 30, 2006.

The Settlement Agreement provides that (1) PG&E will keep its front counters open pending the resolution of this matter in Phase 2 of this GRC proceeding either through settlement or a Commission decision, and (2) PG&E should be granted $37.1 million annually to operate all of its front counters. If any front counters are closed, PG&E will adjust its rates downward to reflect the savings from such closures.[12]

On February 7, 2007, PG&E filed a notice of a settlement conference on February 15, 2007, to discuss the potential resolution of all front-counter issues.

b. Discussion

The evidentiary record shows that PG&E's front counters are heavily used. Approximately 10% of all customer transactions occur at the front counters. During 2005, there were 4,560,387 payment transactions at the front counters and 1,080,918 non-payment transactions.[13]

The importance of the front counters to PG&E's customers was highlighted at the Public Participation Hearings (PPHs). Many of the speakers at the PPHs said that PG&E's front counters are often the only way to resolve customer service issues. For example, several speakers emphasized that PG&E's front counters provide vital services to farm communities. These speakers explained that many farm workers do not have checking accounts and rely on front

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[12] Settlement Agreement, para. 24.

[13] Exhibit DRA-9, p. 9-16.

counters to pay their bills in cash and to resolve billing problems. They also described how farmers' difficulties with PG&E can be much more complicated than those of typical residential customers because farmers generally use far more gas and electricity than most residential users, often have multiple meters and utility bills, and the agricultural tariff schedules can be difficult to understand. These speakers described how PG&E's representatives at front counters understand the special needs of farmers and can resolve problems quickly, while the PG&E's representatives in a distant call center are generally unfamiliar with the intricacies of arcane agricultural tariffs.[14]

In light of the clear public need for the services provided by PG&E's front counters, we concur with the Settlement outcome that keeps all front counters open and provides associated funding. To ensure this intent is fulfilled, we will order PG&E to not make any significant reductions to the staffing or operations of its existing front counters without Commission authorization[15] pending the Commission's consideration in Phase 2 of an apparent settlement that has been reached on front-counter issues.[16]

2. Mobile Home Park Billing Service

There are approximately 1,627 mobile home parks (MHPs) in PG&E's service territory with master meters for gas and electric service. These MHPs

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14 See, generally, Reporter's Transcript (RT) of the PPHs held in Woodland and Chico on May 17 and 18, 2006, respectively.

15 PG&E may, of course, make necessary changes to the operations and locations of its front counters in response to circumstances, such as moving the location of a front counter due to the expiration of a lease.

16 As noted previously, on February 7, 2007, PG&E filed a notice of a settlement conference on February 15, 2007, to discuss the potential resolution of all front-counter issues.

have around 89,000 sub-metered tenants. MHP owners are required by Pub. Util. Code § 739.5 [17] to (1) charge their sub-metered tenants the same rates that PG&E charges its directly metered customers, and (2) provide itemized bills to their tenants that have the same general form and content as the utility's bill.

In D.04-11-033, the Commission ordered PG&E to analyze the potential for providing bill-calculation services to MHP owners with sub-metered tenants.[18] On June 27, 2006, PG&E, WMA, and TURN submitted a joint proposal for PG&E to calculate the gas and electric utility bills for sub-metered tenants of MHPs ("Joint Proposal").[19] There is no opposition to the Joint Proposal.

The Joint Proposal is incorporated into the Settlement Agreement. The Settling Parties agree that the Joint Proposal is a reasonable compromise of the parties' positions and complies with § 739.5 and D.04-11-033.[20]

a. Summary of the Bill-Calculation Services

PG&E, TURN, and WMA (collectively, "the Joint Parties") propose that PG&E offer to MHP owners a Bill-Calculation Service like that described in D.04-11-033. MHP owners will have to sign an agreement to use the Services for a minimum of 12 months. Once enrolled, MHP owners will enter information at www.pge.com that PG&E needs to calculate utility bills for each tenant. MHP owners will be responsible for (1) the collection of timely and accurate meter reads, and (2) the submittal of timely meter-read data to PG&E at www.pge.com.

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17 All section references are to the Public Utilities Code unless otherwise noted.

18 D.04-11-033, Ordering Paragraph (OP) 12.

19 The Joint Proposal, which is contained in Exhibit PG&E-70, is modeled on SCE's MHP bill-calculation services approved by the Commission in D.06-05-016.

20 Settlement Agreement, para. 25.

Using information provided by MHP owners, PG&E will calculate sub-metered tenants' bills in accordance with the applicable residential rate schedules and send the bill calculations to the MHP owners via email. PG&E's bill calculations will usually be performed within two business days.

PG&E will handle billing inquiries from MHP tenants by providing tenants with information on the bill calculation and applicable rate schedule. For all other disputes (*e.g.*, usage amounts, meter accuracy, etc.), PG&E will refer the tenant to the MHP owner for resolution and inform the tenant that a complaint may be submitted to the Commission's Consumer Affairs Branch.

The Joint Proposal gives PG&E until June 1, 2007, to begin offering the MHP Bill-Calculation Services in order to provide PG&E with sufficient time to design, develop, test, and implement the Services.

D.04-11-033 requires PG&E's costs for MHP Bill-Calculation Services to be recovered from MHP owners. PG&E intends to recover its costs via the monthly service fee and a special services fee shown in the following table:

Proposed MHP Bill Calculation Service Fees	
Description	**Amount**
One-Time Initial Setup Charge	Free
Monthly Customer Charge Includes: * Development Expense * Bill Calculation Transaction Fee * Bill Presentation	$0.27 per tenant per month
Special Service Fee	Actual labor & materials

PG&E estimates that the one-time costs to develop the Bill-Calculation Services will be $500,000, and that ongoing costs will be $100,000 annually. The estimated costs exclude expenses already recovered in base rates. Assuming development costs are spread over five years, PG&E would need to recover $200,000 per year from MHP owners (for the first five years). The Joint Parties estimate the monthly fee of $0.27 per tenant will recover all costs for MHP Bill-Calculation Services directly from MHP owners.[21] Once the development costs are recovered, PG&E will adjust the monthly per-tenant fee.

The special services fee would apply when a MHP owner requests a service that is not part of the Bill-Calculation Services.[22] Under these circumstances, PG&E would determine the feasibility of the requested service and provide the MHP owner with a cost estimate of the requested service. PG&E would only perform the requested service upon mutual agreement. PG&E will track its actual costs and bill the MHP owner upon completion of the request.

As directed by D.04-11-033, the Joint Proposal includes a draft service agreement and draft tariffs. The proposed agreement includes a description of the Bill-Calculation Services; tenant bill information requirements; a minimum service term of 12 months; and other terms and conditions. The agreement must be signed by the MHP owner prior to receiving Bill-Calculation Services.

b. Discussion

D.04-11-033 required PG&E to submit in the current GRC the following information regarding bill-calculation services for MHP owners:

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21 The Joint Parties estimate that approximately 814 MHP owners with 44,500 tenants will utilize PG&E's bill-calculation service.

22 For example, MHP owners may receive a one-time refund and ask PG&E to perform the bill calculations necessary to allocate each tenant's proportional share of the refund. In this case, the Special Services fee would be assessed per calculation, and would be in addition to the monthly per-tenant fee.

> In their next revenue requirement proceedings, the electric and natural gas utilities shall provide an analysis of the costs, benefits, and feasibility of providing bill calculation services to MHP owners. The utilities shall also provide examples of the appropriate tariff language, and an estimate of the rates necessary to recover the full costs of such services from the MHP owners. (D.04-11-033, OP 12.)

We find that the Joint Proposal satisfies the requirements of D.04-11-033. Consistent with D.04-11-033, the cost of the proposed Bill-Calculation Services will be recovered from MHP owners. Thus, PG&E's other customers will not be affected by the proposed Services.

The proposed Bill-Calculation Services should provide several benefits. First, the proposed Services are substantially similar to SCE's bill-calculation services approved by D.06-05-016.[23] Thus, adoption of the proposed Bill-Calculation Services for PG&E will facilitate statewide consistency in utility bills among sub-metered MHP residents. The proposed Services should also promote statewide consistency between the bills that sub-metered MHP tenants receive and the bills that other utility residential customers receive.

Second, the proposed Services should facilitate the provision of timely and accurate monthly bills to MHP tenants. This will help MHP owners' compliance with § 739.5. Timely utility bills may also help MHP tenants make better decisions about their monthly energy usage.

Third, the proposed Services may be less costly than current methods used by MHP owners to calculate utility bills for sub-metered MHP residents.

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[23] D.06-05-015, *mimeo.*, pp. 341-349.

Finally, bill-calculation issues raised by tenants might be reduced because (1) PG&E may be able to produce more accurate bills and more effectively process rate changes, refunds, and credits, and (2) PG&E will handle tenant bill-calculation questions. This, in turn, should reduce the number of complaints about MHP bills handled by the Commission, which should reduce the burden on the Commission's complaint process.

For the preceding reasons, we will adopt the unopposed Joint Proposal for MHP Bill-Calculation Services. To implement these Services, PG&E shall file an advice letter (AL) in time to begin offering the Services by June 1, 2007. The AL shall contain tariffs and a services agreement that are substantially similar to the proposed tariffs and agreement attached to the Joint Proposal. So long as the AL conforms to today's Opinion, the Energy Division may approve the AL without a Commission resolution.

3. Issues Raised by DRA

All issues raised by DRA regarding Customer Services were resolved by the Settlement Agreement. The following is a summary of the record concerning the issues raised by DRA.

a. Customer Inquiry Assistance

PG&E receives 17 million customer inquiries annually for service, information, and assistance. PG&E handles most customer inquiries through its call centers and the internet. For 2007, PG&E requested $95.7 million for Customer Inquiry Assistance expenses and $1.0 million for capital expenditures.

DRA proposed a disallowance of $3.021 million of PG&E's requested expenses. DRA objected to a $1 million budget transfer in 2005 and a $2.021 million increase between 2006 and 2007 for unidentified internet projects. DRA did not contest PG&E's capital expenditures in this area.

PG&E responded that the $1 million budget transfer opposed by DRA was exactly offset by another budget transfer going the other way, resulting in a net effect of zero. PG&E also contended that DRA's proposed disallowance of $2.021 for unidentified internet projects was unfounded, as PG&E had provided a detailed, multi-page listing of the projects in its work papers.

b. Customer Care

PG&E requested $41.1 million for Customer Care expenses in 2007. PG&E did not seek capital expenditures in this area.

DRA recommended three disallowances. First, DRA recommended a disallowance of $0.26 million for Community Choice Aggregation (CCA) activities. DRA claimed that PG&E had failed to support the expenses because a PG&E data response referenced a blank line in its work papers. PG&E responded that its data response erroneously referred to page 3-5 of its work papers instead of page 3-4. On page 3-4 of its work papers, PG&E provided detailed information supporting the requested amount of $0.26 million.

Second, DRA opposed $0.215 million for expenses that are usually reviewed and recovered in other proceedings. PG&E responded that DRA did not question the reasonableness of the expenses, only the venue for their review and recovery. PG&E argued that the expenses in question are for Customer Services and belong in GRC proceedings with other Customer Services expenses.

Finally, DRA proposed a disallowance of $0.50 million for increased numbers of customer satisfaction surveys on the basis that PG&E had not justified the additional surveys. PG&E responded that the increase in surveys was intended to help PG&E measure and improve customer service.

c. Gas Field Services and Dispatch Operations

Gas Service and Dispatch personnel respond to approximately 3 million customer service requests annually, such as stopping and starting service, pilot relights, appliance safety checks, emergencies, and maintenance work. PG&E requested $100.3 million for Gas Service and Dispatch expenses in 2007 and $14.1 million for capital expenditures.

DRA proposed two disallowances. First DRA recommended a disallowance of $4.4 million for gas service representatives (GSRs), contending that PG&E sought to transfer staff into this function without justification. PG&E responded that DRA ignored some offsetting transfers of staff out of this function. PG&E also represented that DRA's proposal would reduce staffing for GSRs by 21 employees. According to PG&E, the elimination of 21 employees would "severely reduce PG&E's ability to respond to emergencies, to meet customer scheduling commitments…and to complete compliance work. Delayed response to customer requests caused by a reduction in manpower could force customers to attempt to address hazardous service issues themselves…putting themselves, as well as their communities, in dangerous situations.[24]"

Second, DRA recommended a disallowance of $5.4 million of expenses for the Field Automation System (FAS) software upgrade. DRA argued that PG&E's existing software was good enough. PG&E responded that the upgrade was needed because the existing software is obsolete, costly to support, and lacks many of the features of the software upgrade that would help PG&E to maintain and improve customer service.

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24 Exhibit PG&E-18, pp. 27-3 to 27-4.

d. Emissions Reduction

PG&E's Emissions Reduction program includes an existing Low Emission Vehicle program and a proposed Low Emission Energy Services (LEES) program. PG&E requested $12.3 million for expenses in 2007 for its Emissions Reduction program and $3.53 million for capital expenditures. PG&E testified that these programs ensure that PG&E complies with regulatory requirements governing the operation of its fleet, are responsive to the Governor's Climate Change Executive Order, and could eliminate more than 1.3 million tons of carbon emissions at a cost below current market values.

DRA recommended two disallowances. First, DRA proposed a disallowance of $1.975 million of capital expenditures for compressed natural gas refueling facilities. DRA believed that two of PG&E's four proposed refueling facilities were not justified because PG&E was uncertain of how many facilities it would install. PG&E responded that it had proposed a range of two to four facilities, but the actual number would depend on the cost of the locations selected. If PG&E selected more expensive locations, it would install fewer facilities, but its total costs would not go down as DRA assumed.

Second, DRA proposed a disallowance of $3.641 million of expenses for the LEES program. For the most part, DRA argued that other parties, and not PG&E's ratepayers, should pay for the expenses requested by PG&E. PG&E responded that its requested expenses are cost effective for ratepayers and would provide significant environmental benefits.

e. Discussion

After reviewing the record, we conclude that the uncontested Settlement outcome for the issues raised by DRA regarding Customer Services is reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Issues Raised by Aglet, TURN, and Others

a. Billing, Revenue, and Records

PG&E's Billing, Revenue, and Records activities include the issuance of customer bills, maintenance of customer account information, payment processing, and revenue reporting. In 2004, PG&E issued over 66 million customer bills and 10 million late-payment notices.

PG&E initially requested $92.1 million in 2007 for Billing, Revenue, and Records expenses and $4.1 million for capital expenditures. TURN recommended averaging certain one-time expenses related to Energy Statement Redesign. PG&E agreed with TURN's recommendation. This concession reduced PG&E's request from $92.1 million to $89.9 million.

b. Customer Service Standards

PG&E presented data concerning its performance under the Quality Assurance Program and the Safety Net Program. PG&E did not request any changes to these programs or any expenses for these programs.

TURN did not raise any issues regarding existing standards, but TURN did propose a new standard. Specifically, TURN proposed a new "shut-off guarantee" that would require PG&E to pay $100 to customers whose gas or electric service is erroneously shut off. PG&E was agreeable to TURN's proposal, although details must still be worked out, such as what constitutes an erroneous shut-off and when the program should start.

The Settling Parties agree that the Commission should adopt a new quality assurance standard for improper shut-offs and that the new standard should be explained via an advice filing to be made by PG&E within 90 days from today's

Opinion. Prior to making its filing, PG&E will meet with interested parties to resolve as many details of the new standard as practicable.[25]

We find the Settlement outcome to be generally reasonable. The program provides two benefits: it provides compensation to the victims of error; and it provides a strong incentive to PG&E to avoid such errors. Our only concern is that the Settlement does not address who will pay for the new program. We conclude that because PG&E is the source of the error, PG&E should bear the cost of the program.

c. Critical Peak Pricing

i. Position of the Parties

PG&E requested $0.52 million in 2007 for increased workload from the expected adoption of a new critical peak pricing (CPP) tariff by the Commission. TURN recommends that the Commission modify the Settlement Agreement to reduce PG&E's revenue requirement by $0.52 million in 2007 for expenses associated with the CPP program. TURN believes the CPP expenses that PG&E seeks to recover in this GRC proceeding are duplicative of the CPP expenses that PG&E has sought to recover in either A.05-01-016 or A.05-06-006.

The salient issue, according to TURN, is whether PG&E notified the Commission in other proceedings that PG&E collects some CPP costs in GRCs. TURN does not believe that PG&E did so. Had the Commission been informed, TURN believes the Commission might have authorized lower amounts for the CPP budgets approved in other proceedings.

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25 Settlement Agreement, para. 23.

PG&E opposes TURN's recommendation and asserts that TURN has offered no evidence to support its allegation of double recovery of CPP costs.

ii. Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to reduce PG&E's revenue requirement for the CPP program by $0.52 million in 2007. TURN's proposal rests on its assumption that CPP funding approved by the Commission in other proceedings might have been lower if the Commission had known that PG&E intended to recover some CPP costs through GRC proceedings. However, PG&E testified that there is no double recovery of CPP program costs,[26] and TURN has presented no evidence to contradict PG&E's testimony. In the absence of any evidence of double-counting, there is no basis to adopt TURN's recommendation.

d. Direct Access Service Fees

i. Position of the Parties

PG&E's current direct access (DA) service fees were set in 1999 and have not changed since. Because PG&E's costs have increased since 1999, TURN recommends that the Commission (1) increase DA fees by 30%, (2) impose an additional interim charge of $5 on DA customers over 20kW, and (3) examine DA costs and rates in PG&E's rate design proceeding A.06-03-005.

TURN believes its recommendation is consistent with the Commission's decision in the recent SCE GRC proceeding where the Commission addressed the same issue. There, the Commission adopted TURN's proposal to increase SCE's DA fees by 25%. The Commission determined that it was better to adopt

[26] Exhibit PG&E-18, pp. 26-7 and 26-8.

TURN's proposed increase immediately rather than wait for SCE to file an application and continue the subsidization of DA customers by all other customers while the application was processed.[27]

PG&E opposes TURN's proposal. The Settlement Agreement adopts PG&E's position and keeps DA fees at current levels.[28] The Settling Parties maintain that there is insufficient evidence in the record regarding whether, and to what extent, DA fees should be increased.

ii. Discussion

PG&E's DA fees have not changed since 1999 even though PG&E testified that its costs have risen significantly since then.[29] The Settlement Agreement leaves DA fees frozen at their 1999 level. If the fees were correctly calculated in 1999, and the costs have risen significantly since that time, then the fees are too low now. However, there is not enough information in the record to establish accurate, cost-based DA fees. Revising DA fees based on an incomplete record could result in above-cost fees, which would be just as harmful as below-cost fees.

For the preceding reasons, we decline to adopt TURN's proposal to increase DA fees by 30% and to impose an additional $5 charge on DA customers over 20kW. To ensure that PG&E's DA fees are appropriately updated, we will require PG&E to provide an analysis of its DA costs in its next GRC.

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[27] D.06-05-016, *mimeo.*, p. 110.

[28] Settlement, para. 26.

[29] Exhibit PG&E-8, p. 3-3, Table 3-2.

e. Read and Investigate Meters

i. Position of the Parties

PG&E obtains data from gas and electric meters through (i) human meter readers, and (ii) telecommunication technologies that obtain data remotely. PG&E requested $104.7 million for meter reading expenses in 2007.[30]

TURN recommends that the Commission modify the Settlement Agreement to remove $1.027 million for meter-reader employee turnover. These expense are not justified, according to TURN, because PG&E has meter-reader attrition of 20% annually. Thus, the cost for employee attrition should be captured in the base year and no additional adjustment to PG&E's 2007 expenses is necessary. TURN also argues that PG&E should have lower expenses in the future for meter-reader attrition because of the Advanced Metering Initiative (AMI) project, which will eventually replace most meter readers.

PG&E responds that it will have increased expenses for employee turnover because of its aging workforce. Because meter readers are entry-level positions, PG&E expects increased turnover of meter readers as they leave their positions for higher-level positions vacated by retirees.

ii. Discussion

The record shows that PG&E has experienced increased turnover among meter readers in recent years. In 2004, PG&E experienced 20% turnover, followed by 29% in 2005. PG&E testified that it expects 35% turnover in 2006 as more entry-level meter readers are promoted to positions vacated by

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30 PG&E reduced its requested meter reading expense in 2007 by $0.068 million in response to TURN's proposed reduction for the Itron Maintenance Contract.

retirements.[31] Based on this evidence, we conclude that PG&E's request for an additional $1.027 million to hire and train meter readers in 2007 is reasonable.

We agree with TURN that PG&E's expenses for meter-reader turnover should decline after 2007 as meter readers are phased out due to the AMI program. Even so, the declining costs for employee turnover should be reflected in the Stipulated AMI Project Benefits adopted by the Commission in D.06-07-027.[32] These benefits include anticipated reductions in employee-related costs associated with the AMI program. As a result, it would be double counting to reflect these declining costs in this GRC proceeding.

For the preceding reasons, we conclude that the Settlement outcome for meter-reading expenses is reasonable in light of the record, consistent with applicable law, and in the public interest.

f. Uncollectibles Factor

i. Position of the Parties

Uncollectibles expense is equal to the uncollectibles factor times billed revenue. PG&E requested authority to increase its uncollectibles factor from 0.002 to 0.002772.[33] DRA recommended 0.002582 based on a five-year average.

The Settlement adopts an uncollectibles factor of 0.002586.[34] The Settling Parties submit that this outcome is reasonable because it is the midpoint between

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31 Exhibit PG&E-18, pp. 28-2 and 28-3.

32 D.06-07-027, *mimeo*., pp. 29-30.

33 The assigned ALJ removed from consideration in the instant proceeding PG&E's proposed 0.015% adder "to accommodate additional write-off as a result of implementation of the late payment fee." (Exhibit PG&E-5, p. 8-10.)

34 Settlement Agreement, para. 20.

PG&E's request and Aglet's recommendation (discussed below), and is very close to DRA's recommendation.

Aglet recommends an uncollectibles factor of 0.00240, which is equal to the recorded value for 2005. Although the 2005 recorded uncollectibles factor was below PG&E's 19-year average, Aglet believes that PG&E can sustain its credit and collections success into 2007. This is because Aglet believes the uncollectibles factor has been trending down and that PG&E plans to implement measures that will keep the uncollectibles factor at its current low level.

PG&E responds that the 2005 recorded uncollectibles factor was unusually low relative to the five-year average of 0.002586 and the 19-year average of 0.0028, and will likely increase in 2007.

ii. Discussion

We find the uncollectibles factor of 0.002586 adopted by the Settlement is reasonable. The adopted uncollectibles factor is equal to the five-year average.

We are not persuaded by Aglet that it is better to use the 2005 recorded uncollectibles factor of 0.00240. We agree with PG&E's assessment that the 2005 uncollectibles factor was low relative to the five-year and 19-year averages, and will likely rise in 2007. In fact, PG&E testified that uncollectibles were growing in early 2006 due to increasing natural gas prices and the recent Winter Customer Care and Relief Program.[35] Although Aglet contends that PG&E has implemented measures that should enable PG&E to maintain its low 2005 uncollectibles factor, the supporting evidence cited by Aglet is unconvincing. Specifically, the PG&E exhibits cited by Aglet generally show that PG&E has

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[35] Exhibit PG&E-18, p. 31-2, L: 17-24; 24 RT 2196:23 to 2197:5, PG&E/Torres.

taken steps to improve the efficiency of its Credit Operations in order to absorb increased workload without an increase in costs. In our opinion, there is no clear linkage between the steps taken by PG&E to improve its organizational efficiency and continuation of the relatively low uncollectibles factor in 2005. In any event, PG&E testified that it has suspended its efforts to improve the efficiency of its Credit Operations, which weakens Aglet's argument.[36]

We conclude for the previously stated reasons that the Settlement outcome with respect to the uncollectibles factor is reasonable in light of the record, consistent with applicable law, and in the public interest.

g. Late-Payment Fee Implementation Expense

i. Position of the Parties

PG&E initially requested a total of $0.481 million over 2007 - 2009 to implement a late-payment fee. Subsequently, issues regarding the late-payment fee were removed from this proceeding pursuant to a ruling by the assigned ALJ.

Aglet recommends that the Commission take steps to ensure that the revenue requirement adopted by today's Opinion excludes expenses for the late-payment fee. PG&E responds that Aglet's recommendation is moot because late-payment fee expenses were excluded from the Joint Comparison exhibit on which the Settlement Agreement is based.

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[36] Exhibit PG&E-18, p. 31-4, L: 1-9; Exhibit PG&E-5, p. 8-5, L: 28-32. The suspension of PG&E's efforts to improve the efficiency of its Credit operations is driven by uncertainty regarding the outcome of the ongoing Billing and Collections phase of I.03-01-012.

ii. Discussion

On May 31, 2006, the assigned ALJ issued a ruling that removed from this proceeding all issues associated with PG&E's proposed late-payment fee and notified the parties that such issues would be considered, as appropriate, in I.03-01-012. We affirm the ALJ's Ruling.

Based on PG&E's representations, described above, we are satisfied that there are no late-payment fee expenses included in the revenue requirement adopted by today's Opinion. Aglet asks us to take unspecified measures to ensure that such costs are excluded from the adopted revenue requirement. We do not see a need for additional measures, since the costs in question are already excluded from the revenue requirement adopted by today's Opinion.

h. Service-Restoration Fee

i. Position of the Parties

Currently, when a customer's service is shutoff for nonpayment, PG&E charges a $20 fee to restore service during regular hours and $30 after hours. PG&E requested a phased increase in the service restoration fee to $40.00 during regular business hours and $60.00 during non-business hours to reflect PG&E's actual costs. DRA recommended that the fee increase be limited to 25% for reasons of affordability. DRA further proposed that CARE customers receive a 20% discount on the fee.

The Settling Parties agree that the service-restoration fee should be increased from $20.00 during regular business hours and $30.00 during non-business hours to $25.00 and $37.50, respectively. The Settling Parties also agree that CARE customers should be exempted from the increase.[37] The Settlement essentially adopts DRA's position.

Aglet concurs with the Settlement for three reasons. First, Aglet agrees that a fee increase is necessary, but Aglet contends that PG&E's requested fee exceeded PG&E's actual costs for service restoration. Second, DRA's recommended 25% fee increase provides an orderly transition to cost-based rates. Finally, Aglet submits that it is reasonable to retain a higher fee for overtime and holiday work, which is generally more expensive than work done during regular hours. Aglet believes a single rate would send the wrong price signal, encouraging customers to seek reconnections outside of regular hours.

ii. Discussion

We find the uncontested Settlement outcome for the increased service restoration fee is reasonable for the reasons given by DRA and Aglet, is consistent with applicable law, and is in the public interest.

i. Non-Sufficient Funds Fee

i. Position of the Parties

PG&E requested authority to increase its fee for bounced checks from $8.00 to $11.50. The Settlement adopts PG&E's request.[38] The Settlement Agreement also requires PG&E to file, within 30 days, a compliance advice letter to implement the increased fee.

TURN does not oppose an increased fee. TURN observes that PG&E justifies the increased fee for bounced checks based on increased working-cash

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[37] Settlement, para. 22.

[38] Settlement, para. 21.

expense. PG&E explains that it takes an average of 36 days for a replacement check to post after the initial check bounces, causing an average working-cash expense of $4.13 per bounced check. TURN argues, however, that PG&E's proposed fee structure should be rejected because it ignores that working-cash costs vary with the size of the bounced check and, as a result, requires smaller customers to subsidize larger customers.

To remedy this inequity, TURN proposes a fee equal to $6.50 plus 1% of the bounced check. TURN states that tying the fee to the amount of the bounced check results in customers paying a fee that reflects the actual costs they impose on PG&E. Under TURN's proposal, the average fee would be $9.20 for residential customers and $22.12 for non-residential customers.

TURN alternately proposes that separate flat fees be adopted for each customer class based on class-average costs. TURN believes a class-based flat fee would be easy for customers to understand, easy for PG&E to implement, and reduce the cross-subsidization among customer classes.

Although PG&E does not currently have a late-payment fee, the Commission is scheduled to consider the imposition of a late payment fee in another proceeding. TURN recommends that the Commission protect customers against possible double collection of working-cash costs by modifying the Settlement Agreement to indicate that any increase to the bounced-check fee will be reconsidered if a late-payment fee is instituted before PG&E's next GRC.

PG&E opposes TURN's proposals. First, PG&E asserts that TURN's variable fee of $6.50 plus 1% of the bounded check would be confusing to customers and costly for PG&E to implement. Second, PG&E contends that TURN's alternate proposal for separate flat fees for each customer class is not adequately supported by record evidence. Finally, PG&E states that TURN may raise its concerns about the possible double recovery of working-cash costs from the imposition of a late-payment fee in I.03-01-012 where the Commission is scheduled to address PG&E's proposal to implement a late-payment fee.

ii. Discussion

There is no dispute that PG&E's costs for bounced checks have increased and that PG&E should be allowed to establish a fee structure to recover the increased cost. The only dispute is the nature of the fee structure.

We find that the Settlement Agreement's adoption of an increased flat fee of $11.50 is reasonable because it will enable PG&E to recover its rising costs for bounced checks, is easy for customers to understand, and will be less costly for PG&E to implement than other approaches.

We decline to adopt TURN's variable-fee because, as PG&E testified, it would be more confusing to customers than a flat-fee and more costly to implement than a flat-fee.[39]

On the other hand, we find merit in TURN's alternative proposal for a separate flat fee for each customer class. We agree with TURN that such an approach would reduce the cross subsidies inherent in a single flat-fee, which is a worthwhile goal. However, as noted by PG&E, there is no supporting record for specific flat fees. Therefore, we decline to adopt class-specific flat fees at this time. We will revisit this issue in PG&E's next GRC. There, PG&E shall provide a separate, cost-based flat fee for each of the major customer classes and supporting work papers.

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[39] Exhibit PG&E-18, p. 31-16, L: 17-27.

We decline to adopt TURN's proposal to modify the Settlement to state that the increased fee for bounced checks adopted today will be reconsidered if a late-payment fee is implemented before PG&E's next GRC. We intend to address PG&E's proposed late-payment fee in I.03-01-012.[40] TURN can raise in that proceeding its concerns about possible double recovery of working-cash costs from the imposition of both a late-payment fee and a bounced-check fee.

For the preceding reasons, we find the Settlement outcome for the bounced-check fee is reasonable in light of the record, consistent with applicable law, appropriately balances the interests at stake, and is in the public interest. As set forth in the Settlement, PG&E shall file a compliance advice letter within 30 days from the effective date of today's Opinion to implement the revised fee.

j. Customer Retention & Economic Development

i. Position of the Parties

(A) The Settlement Agreement

PG&E's Customer Retention and Economic Development program supports efforts to (1) retain customers, assets, and service territory that would otherwise be acquired by publicly-owned utilities; (2) attract, retain, or expand businesses that have the option to locate outside of PG&E's service territory; and (3) acquire the utility distribution facilities on military bases.

PG&E requested $4.35 million in 2007 for Customer Retention and Economic Development expenses. The components of PG&E's request were as follows: (a) $2.03 million for customer retention, (b) $1.65 million for economic

40 See Administrative Law Judge's Ruling Removing From This Proceeding All Issues Regarding Pacific Gas and Electric Company's Late Payment Fee, issued on May 31, 2006.

development, (c) $0.35 million for acquisition of military facilities, and (d) $0.32 million for regulatory/legislative activities. PG&E did not request capital expenditures in this area. DRA did not address this matter.

The Irrigation Districts opposed any ratepayer funding for customer retention and economic development. They argued that the primary purpose of PG&E's activities in this area is to combat the loss of service territory and customers to publicly owned utilities. In addition, Merced ID and Modesto ID called for an investigation of PG&E's implementation of Schedule E-31 to determine if abuses are occurring.[41] Modesto ID also called for an investigation of PG&E's compliance with the Removal of Idle Facilities Agreement.[42]

The Settlement resolves the disputes between PG&E and the Irrigation Districts by providing zero funding for customer retention, while continuing to fund economic development, acquisition of military facilities, and regulatory/legislative activities.[43] Additionally, Modesto ID and Merced ID agree to withdraw, for now, their requests for an investigation of PG&E's implementation of Schedule E-31.[44] Modesto ID also agrees to withdraw, for now, its request for an investigation of PG&E's compliance with the Removal of

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41 Schedule E-31, Distribution Bypass Deferral Rate, was approved pursuant to § 454.1. This statute authorizes PG&E to offer discounted electric service when there is a competing, bona fide service offer from an irrigation district.

42 D.04-05-055, issued in PG&E's 2003 GRC proceeding, adopted the Removal of Idle Facilities Agreement that was signed by PG&E and Modesto ID. This Agreement requires PG&E to remove certain idle facilities and was intended to address Modesto ID's concern about PG&E leaving idle electric distribution facilities in place, and presumably in rate base, for long periods of time. The Agreement expires on December 31, 2006, unless PG&E and Modesto ID agree to extend it.

43 Settlement Agreement, para. 19.

44 Settlement Agreement, para. 50.

Idle Facilities Agreement in light of a commitment between the parties to negotiate possible revisions to that Agreement.[45]

(B) Aglet

Aglet opposes the Settlement provisions that provide $1.65 million of ratepayer funding for economic development. Alternatively, Aglet proposes a disallowance of $0.50 million for trade shows, marketing, and economic development organizations.

Aglet observes that the objective of PG&E's economic development is to attract, retain, or expand businesses that have the option of locating outside of PG&E's service territory. Aglet opposes ratepayer funding of economic development because it is unrelated to the delivery of safe and reliable utility service. Nor is there any societal benefit, since one utility's loss is another's gain.

Aglet maintains that PG&E has not shown that it is cost effective for ratepayers to fund economic development. The Commission uses the ratepayer impact measure (RIM) to determine the cost effectiveness of economic development expenditures. The RIM is equal to the net present value of future revenues from business customers that are attributed to PG&E's economic development efforts, less PG&E's marginal cost to serve these customers and the cost of PG&E's Economic Development program.[46] Ratepayers benefit if the net present value exceeds zero. Aglet argues that PG&E's RIM calculations have two fatal flaws. First, Aglet presented information which purports to show that electricity costs are not crucial to most location decisions by California businesses. Aglet posits that 83% of the revenues that PG&E includes in its RIM

[45] Settlement Agreement, para 49.

[46] Exhibit PG&E-5, p. 9-15, Footnote 11.

calculations should be excluded to reflect the fact that electricity costs play a small role in business location decisions.

Second, Aglet asserts that PG&E's RIM calculations assume that the marginal cost to serve the business load that results from PG&E's economic development efforts will remain unchanged for the foreseeable future. The reality, according to Aglet, is that marginal costs will increase over time. If rising marginal costs are factored in, ratepayers are worse off under the RIM test.

(C) TURN

TURN opposes the Settlement's provision of $1.65 million for economic development. TURN notes that the requested funding is double what PG&E was granted in its last GRC and double PG&E's recorded expenditures in 2004. TURN contends that PG&E has not justified a 100% increase in costs, choosing instead to fall back on the claim that the requested spending is warranted under the RIM test. As an alternative, TURN proposes that the Commission limit ratepayer funding for economic development to PG&E's expenditures in 2004.

TURN also opposes the Settlement's provision of $0.32 million for regulatory/legislative activities tied to economic development. TURN believes these activities provide few or no benefits to ratepayers, duplicate the activities of other departments, and probably include below-the-line lobbying activities.

(D) PG&E and the Other Settling Parties

PG&E responds that its requested funding for economic development is consistent with Commission precedent. In D.05-09-018, which approved SCE's and PG&E's applications for economic development rates, the Commission made the following findings of fact:

> 1. The cost of electricity is a major cost of doing business in California. By some estimates electric rates cause about

> one sixth of what some experts believe is the overall 30% cost premium for doing business in California.
>
> 2. The implementation of successful economic development projects benefits ratepayers by (a) increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers, and (b) providing increased employment opportunities and improved overall local and economic vitality. (D.05-09-018, *mimeo*., p. 27.)

Furthermore, the Commission explained:

> Section 740.4(h) of the Pub. Util. Code requires the Commission to allow recovery through rates of expenses and rate discounts supporting economic development programs to the extent that ratepayers "derive a benefit from those programs." As the utilities have demonstrated, the implementation of successful economic development projects would benefit ratepayers directly by increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers. (D.05-09-018, *mimeo*., p. 13.)

The Commission also addressed ratepayer funding of economic development in SCE's most recent GRC proceeding. Citing the above-quoted findings in D.05-09-018, the Commission concluded that SCE's economic development program should be adopted with full ratepayer funding.[47]

In rebuttal to TURN, PG&E states that its economic development activities do not include any below-the-line lobbying costs. This is because the work performed by the Economic Development organization is done by different

[47] D.06-05-016, *mimeo*., p. 115.

people and is different in kind from the regulatory work undertaken by PG&E's Public Policy and Governmental Affairs personnel.

ii. Discussion

Ratepayer funding for economic development is subject to § 740.4(a). This statute states, "The commission shall authorize public utilities to engage in programs to encourage economic development." § 740.4(c) sets forth the scope of economic development activities, which include business expansion, relocation, retention, and recruitment. §§ 740.4(b) and 740.4(h) allow rate recovery of utility economic development expenses to the extent of ratepayer benefit.

There is no dispute that PG&E's economic development activities fall within the scope of § 740.4. In light of the guidance provided by § 740.4, we conclude that PG&E should be authorized to recover economic development expenses in 2007 as set forth in the Settlement Agreement, but only to the extent that such expenses benefit ratepayers. Consistent with Commission precedent, we will use the RIM test to evaluate ratepayer benefits.[48]

PG&E's RIM calculations show that its economic development expenditures are cost effective for ratepayers, even if 95% of the businesses that benefit from PG&E's expenditures would have located in PG&E's service area absent such expenditures.[49] Aglet presents two criticisms of PG&E's RIM calculations, both of which are unpersuasive. First, Aglet contends that the revenues included in PG&E's RIM calculations should be reduced by 83% to reflect Aglet's claim that electricity costs are a minor factor in business location decisions. Aglet's criticism is moot, as PG&E's RIM calculations show that its

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[48] D.95-06-016, Attachment 1, 60 CPUC2d 265, 277.

[49] Exhibit PG&E-5, p. 9-18.

Economic Development program is cost effective even if 95% of the businesses that benefit from the program are free riders.

Second, PG&E's RIM calculations assume that the marginal cost to serve the load that results from PG&E's economic development efforts will remain unchanged for the foreseeable future. Aglet contends that if rising marginal costs are factored in, ratepayers would be worse off under the RIM test. However, Aglet overlooks the fact that PG&E also used the same marginal revenue throughout this period.[50] While we agree with Aglet that marginal costs will probably rise over the 10-year period reflected in PG&E's RIM calculations, it is just as likely that PG&E's marginal revenue will increase as well. We believe that PG&E's RIM calculations would show that PG&E's economic development expenditures are cost effective for ratepayers if both rising marginal costs and rising marginal revenues are factored in.

TURN criticizes the RIM test for economic development expenditures, claiming that PG&E should "demonstrate that each new expenditure will yield ratepayer benefits rather than hiding behind an overall RIM test analysis for the aggregate spending level.[51]" We disagree. The Commission previously held that the following standards set forth in D.95-06-016 should be used to evaluate the cost-effectiveness of utility economic-development programs[52]:

> [All] cost-effectiveness and program analysis should be conducted at the end use level, as defined for each program by the protocols governing the measurement and evaluation

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50 PG&E's RIM calculations used a marginal cost of $0.0549/kWh and a marginal revenue of $0.12200/kWh. (Exhibit PG&E-5-WP09, p. 9-24.)

51 TURN's comments on the Settlement Agreement, p. 37.

52 See, for example, D.04-07-022, 2004 Cal. PUC LEXIS 325, *208.

> of…programs, as well as the program as a whole. The "program as a whole" includes any miscellaneous measure for which an end use is not designated for measurement. If the adopted measurement protocols do not specify or require measurement at the end use level, cost-effectiveness analysis should be applied at the level of the program as a whole. (D.95-06-016, Attachment 1, Fn. 2.)

Using the criteria in the above-cited decision, we find that because PG&E's Economic Development program as currently structured contains no-end use elements, the "program as a whole" standard should apply to PG&E's economic development expenditures. This is what PG&E did in its RIM test calculations.

For the preceding reasons, we find that PG&E's requested economic development expenditures are cost effective for PG&E's ratepayers, and that PG&E should be allowed to recover all of its requested expenses for economic development pursuant to § 740.4. We decline to adopt Aglet's alternate recommendation to disallow $0.50 million for trades shows, marketing, and economic development organizations. These activities appear to be an important element of PG&E's Economic Development program, and failure to fund these activities would likely diminish the effectiveness of the program.[53]

For the same reason, we decline to adopt TURN's proposals to (1) limit funding for PG&E's economic development to the 2004 recorded level of $0.97 million, and (2) disallow $0.32 million of requested funding for the

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53 PG&E's RIM calculations do not appear to have included $0.50 million for trade shows, marketing, and economic development organizations. However, because PG&E's calculations show $3.48 million of net benefits at a 95% free rider rate (Exhibit PG&E-5, p. 9-16), the inclusion of an additional $0.50 million of costs in the RIM calculations would not change our conclusion herein that PG&E's economic development expenditures are cost effective for ratepayers.

regulatory/legislative component of PG&E's Economic Development program. We caution PG&E that it should not use any economic development funds to engage in below-the-line lobbying activities. We expect PG&E to keep records that demonstrate no below-the-line lobbying was funded with economic development funds.

5. Conclusion re: Customer Services

Based on our review of the record, we conclude that the Settlement Agreement provisions regarding Customer Services are reasonable in light of the record, consistent with the law, and in the public interest.

B. Electric Distribution

1. Electric Distribution Revenues

DRA was the only party that presented testimony on PG&E's present and forecasted electric retail revenues. DRA and PG&E agreed on forecasted billings, sales, and electric revenues at present rates.

Modesto ID questioned PG&E's treatment of non-bypassable charges for departing load customers in the computation of revenues at present rates. PG&E responded that departing load customers are not included in the computation of GRC revenues; these computations deal strictly with retail revenue accounts.

The Settlement adopts PG&E's forecasts of Electric Distribution billings, sales, and revenues at present rates. There is no opposition to the Settlement outcome on this matter. We concur with this outcome.

2. Electric Distribution O&M Expenses

PG&E requested $494 million for Electric Distribution operation and maintenance (O&M) expenses in 2007. DRA proposed $462 million, for a difference of $32 million. TURN also proposed several disallowances.

The Settlement Agreement adopts $489 million. The following table compares the Settlement outcome to PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Electric Distribution O&M Expenses ($ millions)							
		Comparison Exhibit			Variances Increase/(Decrease)		
	2006 Authorized	PG&E	DRA	Settlement	Settlement vs. 2006	PG&E vs. Settlement	DRA vs. Settlement
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
O&M	443.9	494.2	461.7	488.8	44.9	(5.4)	27.1
Source: Settlement Agreement, Appendix B, Line 1.							

The Settling Parties agree that the O&M labor factors for all of PG&E's lines-of-business (e.g., gas, electric, and generation) in this proceeding and others will be calculated from 2004 recorded adjusted O&M labor.[54]

Below, we assess the reasonableness of Settlement outcome for Electric Distribution O&M expenses in light of the record on the issues raised by DRA and TURN.

a. Issues Raised by DRA

All issues raised by DRA regarding Electric Distribution O&M expenses were resolved by the Settlement Agreement. The following is a summary of the record concerning the issues raised by DRA.

54 Settlement Agreement, para. 52.

i. Issues Other than Vegetation Management

(A) Distribution Line Equipment Inspect and Test

DRA recommended a disallowance of $0.6 million of PG&E's requested expenses in 2007 for Distribution Line Equipment Inspect and Test. PG&E responded that DRA's proposed disallowance, which was based on a three-year average of data for 2002 - 2004, did not reflect a sharp increase in work in 2005. DRA agreed that data for 2005 indicated a need to increase its forecast of work in 2007, but the parties disagreed on how to adjust the forecast.

(B) Preventative Maintenance

Preventive Maintenance consists of 18 categories of work, three of which were disputed by DRA at the time of the Comparison Exhibit.

(1) Overhead Repairs

PG&E requested $28.5 million for Overhead Repair expenses in 2007. PG&E testified that in 2005 the resources normally assigned to maintenance work were shifted to higher priority work, such as emergency response, storms, and new business. Consequently, PG&E's request for 2007 included work that was rescheduled from 2005.

DRA accepted PG&E's forecast of unit cost, but disputed PG&E's forecasted units of work in 2007. DRA used a four-year average of work during 2002 - 2005 to arrive at its forecast of $23.3 million for 2007, which was $5.2 million less than PG&E's request. PG&E responded that it must perform the rescheduled maintenance work in 2007, and that DRA's averaging technique did not capture the need to perform the rescheduled work in 2007.

(2) BG Projects

BG Projects covers preventive maintenance work that is infrequent or of a limited duration. PG&E requested $3.0 million annually for BG Projects during

2007, 2008, and 2009. Of this amount, $2.2 million was for specific projects that had already been identified, and the rest was for projects that have yet to be identified. DRA recommended a total of $2.2 million during 2007-2009 for only those projects that had already been identified, with no placeholder for projects that could not be identified years in advance.

(3) Other

The Other category consists of special projects that, if grouped in other categories, would skew units and unit costs. PG&E requested $1.2 million for Other work in 2007. DRA proposed $0.4 million, for a difference of $0.8 million. PG&E's forecast was based on specific projects that had been identified for 2007. DRA's forecast was based on the four-year average of expenses during 2002 - 2005. PG&E responded that (1) the 2002 accounting data is anomalous because of a credit that corrected an error from the previous year, and (2) recorded expenses showed a clear upward trend in recent years.

(C) Pole Asset Management

Pole Asset Management expenses consists of three categories of work. PG&E and DRA agreed on PG&E's 2007 request of $1.7 million for Pole Engineering and $6.3 million for Pole Restoration. The only dispute involved Pole Test and Treat expenses. PG&E requested $12.7 million for these expenses in 2007. DRA recommended $11.9 million, for a difference of $0.8 million.

DRA and PG&E disagreed on the forecast of work on inaccessible poles. DRA accepted PG&E's 2007 forecast unit cost of $125, but argued that only 6,000 poles need to be addressed, rather than PG&E's 2007 forecast of 12,710 poles.

PG&E responded that its Pole Test and Treat program is based on a ten-year cycle. When contractors work their assigned lists of poles to test and treat each year, they encounter poles that are not accessible for a variety of reasons, such as locked gates, dogs, customer not home, etc. PG&E's contractors identified approximately 35,000 such poles in prior years.

PG&E testified that it needs to complete the final 12,710 poles in 2007 to remain in compliance with General Order (GO) 165, which requires utilities to test and treat all wood poles over 15 years old once every 10 years. This 10-year deadline did not exist prior to 2007, as GO 165 was adopted in 1997.

(D) Externally Driven Work

Externally Driven Work covers two areas: (1) New Customer Connection expenses, and (2) Work Requested by Others (WRO). There were no disputes regarding the first area.

PG&E and DRA disagree on WRO expenses for pre-parallel inspections.[55] PG&E requested $0.7 million for pre-parallel inspection expenses in 2007, which was based on historical costs of $662,000 in 2004 escalated by 3% annually. DRA objected to any ratepayer funding for pre-parallel inspections because PG&E had not provided historical data aside from 2004 costs.

PG&E responded that prior to 2005, pre-parallel inspection expenses were recorded in transmission accounts, and this was the reason historical data had not been provided in response to DRA's data request.

(E) Conclusion

The Settling Parties agree that the resolution of the previously identified issues raised by DRA is subsumed in the Settlement outcome for Electric

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[55] PG&E and DRA initially had two other areas of dispute regarding WRO expenses. In rebuttal, PG&E agreed with DRA's $10.2 million forecast for relocations, and PG&E agreed to reduce its GIS forecast from $3.5 million to $1.6 million. At hearings, DRA's witness agreed with PG&E's revised GIS forecast.

Distribution O&M expenses. Based on our review of the record regarding these issues, summarized above, we find that PG&E has provided reasonable justification for virtually all of the expenses contested by DRA. The Settlement outcome for Electric Distribution O&M expenses is consistent with our conclusion, in that the Settlement adopts a higher amount for Electric Distribution O&M expenses than recommended by DRA.

ii. Vegetation Management

PG&E requested $154.4 million in 2007 for its Vegetation Management program. PG&E also sought to convert the one-way Vegetation Management Balancing Account to a two-way balancing account due to the significant costs that may be needed to comply with recent interpretations of utility obligations under Pub. Resources Code § 4293 by the California Department of Forestry and Fire Protection (CDF).

DRA disagreed with PG&E's requested expenses and PG&E's proposal to convert the one-way Vegetation Management Balancing Account to a two-way balancing account. No other parties addressed this matter. The areas where PG&E and DRA disagreed are summarized below.

(A) Routine Tree Trimming & Removal

PG&E requested $136.7 million in 2007 for Routine Tree Trimming & Removal expenses. DRA proposed $124.6 million, for a difference of $12.1 million. PG&E calculated its 2007 expenses by multiplying its forecast of 1,580,191 units by its forecasted unit cost of $86.51. DRA accepted PG&E's forecast of units but used a lower unit cost of $78.83.

Contract work is the largest expense in this area. PG&E testified that contractor prices are increasing, as demonstrated by the 7.8% increase in contractor prices in 2006 compared to 2005. The reasons for the increased prices include (1) higher costs for labor, insurance, fuel, and environmental compliance, and (2) an increase in the ratio of overhead line miles to tree volume.

DRA used the weighted average of unit cost increases from 2000 to 2005 to forecast unit costs for 2007. DRA's forecasted unit cost of $78.83 in 2007 represented an increase of 1.6% over 2006.

(B) Increased Staffing

PG&E requested $0.7 million in 2007 to increase its Vegetation Management staff from 51 to 58 full-time PG&E employees. The requested new staff consisted of one quality assurance specialist and six tree-trimming foresters. DRA proposed a disallowance of $0.3 million. DRA accepted PG&E's request for one additional quality assurance specialist but recommended only three additional tree-trimming foresters. DRA asserted that its proposed staff increase was sufficient in light of PG&E's compliance level of 99%.

PG&E responded that it was striving not only for excellent compliance statistics, but also to improve customer service and agency relationships.

(C) Recovery of CDF-Mandated Costs

PG&E expressed concern regarding the recovery of costs that could result from the CDF's push to have PG&E substantially increase its inspection, assessment, and removal of trees and limbs. PG&E believes this work is unwarranted and is working with the CDF to allay its concerns. However, if the CDF's current position prevails, PG&E testified that the cost of the Vegetation Management program could increase by $50 million per year.

DRA agreed that ratepayers should fund work required by the CDF. The only disagreement was whether the Commission should establish a two-way balancing account with automatic flow through of CDF-mandated costs as proposed by PG&E, or a memorandum account in which PG&E could record CDF-mandated costs and later seek to recover these costs as proposed by DRA.

(D) The Settlement Agreement

The Settlement provides $150 million for Vegetation Management expenses. This outcome is $4.5 million less than PG&E requested and $8.0 million more than DRA recommended. The Settlement also keeps the Vegetation Management Balancing Account as a one-way balancing account, and allows PG&E to track and recover costs for additional work required by the CDF via a new memorandum account established through the advice letter process.[56]

(E) Discussion

In light of the record evidence recounted above, we find the Settlement outcome for Vegetation Management is reasonable, consistent with the law, and in the public interest. The Settlement expense amount of $150 million is supported by the record. With the one-way balancing account, any part of the $150 million that is not needed for Vegetation Management will be refunded to ratepayers. In addition, the Settlement provisions that permit PG&E to track and recover additional costs for specified CDF actions through an advice filing, subject to audit, are a reasonable compromise of DRA's and PG&E's litigation positions and fairly balance ratepayers' and shareholders' interests.

iii. Other Electric Distribution O&M Expenses

PG&E and DRA agreed on the amount of Electric Distribution O&M expenses in 2007 for the following areas:

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[56] Settlement Agreement, para. 18.

Other Electric Distribution O&M Expenses - Areas Where PG&E and DRA Agree	
Description	**2007 (Millions)**
Operation/Maintain Substation	$27.0
System Automation Maintenance	$3.3
Corrective Maint. Expense	$50.6
Electric Distrib. Major Emergency	$10.9
Electric Engineering and Planning	$19.1
Electric Mapping	$10.9
Develop and Provide Training	$0.8
Maintenance of Other Equipment	$4.2
Operate Electric Distribution	$32.4
Total	**$159.20**

There is no opposition to PG&E's requested expenses in the above table. We find that DRA's review and concurrence with the above costs, combined with the lack of opposition, lends weight to the Settlement outcome that adopts almost all of PG&E's requested Electrical Distribution O&M expenses.

b. Issues Raised by TURN

i. Double Recovery of AMI-Related Costs

(A) Position of the Parties

PG&E testified that the only area where it requested duplicative costs in both this GRC proceeding (A.05-12-002) and the AMI proceedings (A.05-06-028 and A.05-03-016) was Information Technology (IT). The Settling Parties agree that PG&E has removed the duplicative IT costs from this GRC proceeding,[57] and

[57] The specific amounts removed are shown in Appendix G of the Comparison Exhibit. (Exhibit PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.)

that the Settlement eliminates double recovery of IT costs. The Settling Parties further agree that all AMI program costs and benefits will be addressed through the AMI balancing accounts established pursuant to D.06-07-027.[58]

TURN remains concerned about double recovery of AMI program costs. Although the Commission directed PG&E to track AMI program costs and benefits though balancing accounts,[59] TURN believes this will not prevent double recovery. To safeguard ratepayer interests, TURN recommends that the Commission require PG&E to list and audit all expenses and capital expenditures requested in this GRC proceeding that might also be recovered through the AMI program or have to be written off because of the AMI program.

To demonstrate the need for such an audit, TURN cites PG&E's request in the instant GRC proceeding to install and maintain a significant number of residential time-of-use (TOU) meters. Now that the Commission has approved PG&E's AMI program, TURN states that the Commission must consider the risk of authorizing TOU meter costs in this GRC that could be stranded in a few years. TURN posits that simply having a balancing account to track AMI program costs and benefits does not address such concerns.

PG&E opposes TURN's recommendations. PG&E contends that the AMI proceeding addressed all costs and benefits that are incremental to PG&E's GRC. Further, D.06-07-027 requires all AMI program costs and benefits to be tracked and accounted for separately from normal GRC-related operations and costs.[60]

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[58] Settlement Agreement, para. 20.

[59] D.06-07-027, FOF 17, Conclusion of Law (COL) 8, and Ordering Paragraph (OP) 2.

[60] D.06-07-027, *mimeo.*, p. 47.

(B) Discussion

We agree with TURN that it is prudent to closely monitor PG&E's $1.7 billion AMI program. However, we do not believe it is necessary to adopt new requirements at this time regarding oversight of PG&E's AMI program. In D.06-07-027, we ordered PG&E to provide testimony in its next GRC regarding AMI program costs and benefits.[61] TURN will have an opportunity to conduct full discovery at that time on all issues that would otherwise be addressed in TURN's proposed audit. We appreciate TURN's watchdog role, and we encourage TURN to avail itself of the opportunity in the next GRC to carefully scrutinize PG&E's AMI program for duplicative and stranded costs.

For the preceding reasons, we decline to adopt TURN's recommendation to order PG&E to list and audit its AMI program costs.

ii. TURN's Alternate Proposal for TOU Meter Expenses

(A) Position of the Parties

PG&E requested $16.5 million in 2007 for expenses to install electric meters. TURN's primary recommendation, which is addressed, *supra*, is to reduce PG&E's request by $7.6 million. TURN's alternative proposal, which is addressed here, is to reduce PG&E's request by $1.8 million. The Settling Parties agree that the resolution of TURN's proposed reduction of $1.8 million is subsumed in the Settlement outcome for Electric Distribution expenses.[62]

TURN observes that PG&E's request for meter installation expenses in 2007 includes $1.4 million to offset the elimination of the residential TOU meter

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[61] D.06-07-027, FOF 20 and OP 15.

[62] Settlement Motion, p. 33.

installation charge in 2006. PG&E assumed that it would install 5,000 residential TOU meters annually during 2007 through 2009, while not receiving the $277 per-meter installation charge as it has in previous years. TURN submits that the AMI program will reduce and eventually eliminate TOU meter installations. As result, TURN believes that PG&E's forecast of TOU meter installations is too high, and recommends that the Commission modify the Settlement Agreement to remove the $1.4 million.

PG&E also requested $0.4 million for capital expenditures in 2007 to install 5,000 RTOU meters annually during 2007-2009. TURN recommends that the Commission modify the Settlement Agreement to deny PG&E's request to prevent these capital expenditures from being stranded as TOU meters are replaced under the AMI program.

Finally, PG&E forecasted a net increase in TOU meters from 11,671 in 2004 to 20,700 in 2007. TURN states that it would be imprudent to forecast a corresponding increase in maintenance costs for TOU meters that will likely be replaced during the GRC cycle as a result of PG&E's AMI program.

PG&E opposes TURN's recommendations. PG&E forecasts an increase in the number of installed TOU meters during the GRC cycle and, as a result, PG&E will incur higher maintenance and other costs. At the same time, because the Commission has eliminated the installation fee for TOU meters, PG&E will have less revenue to offset costs related to TOU meters.

(B) Discussion

The premise of TURN's proposed disallowance is that PG&E will not incur its forecasted level of expenses and capital expenditures for TOU meters during the GRC cycle because TOU meters will be replaced over the next few years by the AMI program. We agree that TOU meters will eventually be replaced, but until that occurs PG&E will continue to have TOU-related costs.

PG&E testified that current demand for TOU meters is strong, and PG&E forecasts a net increase of 5,000 TOU customers annually through 2007. The strong demand is likely fueled, in part, by the elimination of the TOU meter installation charge by D.05-11-005.[63] PG&E must meet that demand, as PG&E is required by its tariffs to provide TOU service to customers that request it.[64]

For the preceding reasons, we decline to adopt TURN's proposal to reduce PG&E's revenues requirement for TOU meters. Moreover, the proposal is largely moot, as any savings from the replacement of TOU meters should already be reflected in the Stipulated AMI Project Benefits adopted by D.06-07-027.

iii. Cessation of TOU Meter Installations

(A) Position of the Parties

TURN recommends that the Commission order PG&E to stop installing TOU meters because the newly installed TOU meters will be replaced within a few years by PG&E's AMI program. PG&E responds that it cannot not stop installing TOU meters because it is required by its tariff to provide a TOU meter to any customer who requests it. TURN replies that PG&E should file a petition to modify the decision directing PG&E to install TOU meters.

(B) Discussion

We decline to adopt at this time TURN's proposal to require PG&E to stop installing TOU meters. TURN did not address what effect its proposal might

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[63] D.05-11-005, *mimeo*., pp. 9, 10, and 33.

[64] Exhibit PG&E-15, pp. 21-3 and 21-4.

have on the Commission's policy of relying on demand side management (DSM) as one way to reduce the need for new generation resources and to combat global climate change. TOU meters advance the Commission's policy. We share TURN's concern about the cost-effectiveness of TOU meters in light of PG&E's impending AMI roll out, but TURN's proposal to cease installing TOU meters needs to evaluated in the context of our policy of promoting DSM. We do not have a sufficient record to do so here.

iv. Forecasted Meter Expenses for 2007

(A) Position of the Parties

PG&E records expenses to install electric meters in its internal account Major Work Category (MWC) EY - Install Electric Meters and Devices. PG&E initially requested $17.1 million for MWC EY in 2007, but subsequently agreed to two reductions: (1) DRA's reduction of $0.335 million to normalize costs for Analog Cell Phone Replacement over the three-year GRC, and (2) TURN's reduction of $0.238 million normalize costs for the Agricultural Diesel Irrigation Pumping Conversion program over the three-year GRC. These two adjustments reduced PG&E's request for MWC EY in 2007 to $16.5 million. With these two adjustments, PG&E and DRA no longer had any disputes regarding MWC EY, but PG&E and TURN continued to disagree on other aspects of MWC EY.

TURN submits that PG&E's request for $16.5 million is unreasonable because it is 229% higher than 2005 recorded costs of $7.2 million. TURN recommends that the Commission modify the Settlement to set PG&E's revenue requirement for MWC EY in 2007 at $9.2 million, which is $7.3 million less than PG&E requested. TURN's proposal is equal to PG&E's average annual costs for 2004 and 2005 escalated to 2007 by customer growth of 1.6% annually.

PG&E responds that TURN's reliance on 2004 and 2005 recorded expenses fails to capture significant additional expenses in 2007. PG&E provided four examples to demonstrate this point. First, PG&E's recorded expenses in 2005 were reduced by $3 million due to increased capitalization of labor costs associated with a concerted effort to replace obsolete meters. PG&E forecasts a more normal meter replacement effort in 2007, resulting in a $3 million increase in expenses (and a corresponding $3 million reduction in capitalized labor costs).

Second, in D.05-11-005 the Commission eliminated the installation charge for TOU meters, thereby reducing PG&E revenues by $1.4 million in 2007 relative to 2004. These revenues were previously used to offset PG&E's revenue requirement for MWC EY. PG&E states that it must recover the lost revenue in 2007 through a higher revenue requirement for MWC EY.

Third, PG&E forecasts a significant increase in the number of TOU meter installations in 2007 because of the elimination of the installation charge, which will cause a corresponding increase in installation expenses.

Finally, PG&E forecasts a substantial increase in electric meter installations for agricultural customers in light of the State's policy to reduce air pollution by converting diesel-powered irrigation to utility electric service as part of the Agricultural Diesel Irrigation Pumping Conversion (Ag-ICE) program.

(B) Discussion

PG&E requested an increase of 229% for MWC EY expenses in 2007 compared to recorded costs in 2005. We find that PG&E has justified most of this increase for the reasons summarized above, but not all of the increase.

The Settling Parties agree that the resolution of this matters is encompassed within the Settlement outcome for Electric Distribution expenses for O&M and Customer Services.[65] The Settlement Agreement adopts a revenue requirement of $736 million in 2007 for Electric Distribution expenses for O&M and Customer Services, which is $9 million less than PG&E requested and $29 million more than DRA recommended.[66] We conclude that the portion of MWC EY expenses that PG&E has not justified is subsumed in the Settlement's reduction of PG&E's requested Electric Distribution expenses.

For the preceding reasons, we find the Settlement outcome for MWC EY is reasonable in light of the record. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to reduce funding for MWC EY.

v. Revised Accounting for Meters

(A) Position of the Parties

PG&E records its costs for electric and gas meters in its internal expense accounts MWC EY (electric) and MWC HY (gas). Some of these costs are eventually transferred to, and capitalized in, the internal asset accounts MWCs 25 (electric meters) and 74 (gas meters). TURN contends that PG&E should capitalize meter costs in MWCs 25 and 74 immediately without clearing them through MWCs EY and HY. TURN believes its recommendation would allow parties and the Commission to more easily evaluate whether PG&E's meter expenses and capitalized costs are reasonable.

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[65] Settlement Motion, p. 33.

[66] Settlement Motion, p. 21, Table 3; Settlement Agreement, Appendix B, p. 24, L: 1, 2.

PG&E opposes TURN's recommendation and states that it properly accounts for capitalized meter costs.

(B) Discussion

TURN has not shown that PG&E's accounting is erroneous. We decline to meddle with PG&E's internal accounting system by adopting TURN's proposal. It appears that PG&E has provided to TURN and the other parties sufficient information to enable them to understand and analyze PG&E's meter expenses and capitalized meter costs. We expect PG&E to do so again in its next GRC.

c. Conclusion

Based on our review of the record, we conclude that the Settlement Agreement outcome for Electric Distribution O&M expenses is reasonable in light of the record, consistent with the law, and in the public interest.

3. Electric Distribution Capital Expenditures

PG&E requested $862.0 million for Electric Distribution capital expenditures in 2007. DRA recommended $816.9 million, for a difference of $45.1 million. No other parties addressed this matter. The Settlement adopts PG&E's request.[67]

There is no opposition to the Settlement outcome on this matter. Below, we review the record regarding the issues raised by DRA in order to assess the reasonableness of the Settlement outcome for Electric Distribution capital expenditures.

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[67] Settlement Agreement, Appendix G, Table 4-1.

a. Summary of the Record

i. Pole Asset Management

PG&E requested $94.1 million to replace 15,000 utility poles in 2007 at a unit cost of $6,276. DRA recommended a 5% reduction in the unit cost and a reduction of 1,000 in the number of units, resulting in a forecast of $83.5 million.

PG&E responded that DRA's proposed reduction in unit costs ignored the shift that has occurred in the location of the poles to be replaced. PG&E represented that it will be replacing relatively more poles in the high-cost urban areas, thereby increasing costs above historical levels.

PG&E further contended that DRA's forecast of replacing 14,000 poles annually failed to address the "bubble" of pole replacements that must be done to stay in compliance with safety standards set forth in GO 95 and to proactively address aging infrastructure.

ii. Undergrounding Projects

PG&E requested $55 million for capital expenditures in 2007 for undergrounding projects. DRA proposed a $5 million disallowance based on past spending. PG&E responded that historical spending should not be used to estimate future expenditures in this area because historical spending had been suppressed by the energy crisis, PG&E's bankruptcy, and the need to fund higher priority projects.

iii. Tie-Cable Circuits

Tie-cable circuits connect distribution substations together. Most tie-cables are more than 40 years old. PG&E requested $19.1 million for capital expenditures in 2007 to replace tie-cables. DRA proposed $10.9 million, for a difference of $8.2 million. DRA believed that a lower level of spending was appropriate given that tie-cables are reliable and are usually operated in parallel.

PG&E responded that its tie-cables are failing with increasing frequency because of their age. PG&E explained that because tie cables are a crucial part of its distribution system, the aging tie cables need to be replaced expeditiously to maintain system reliability. PG&E's expert witness explained why higher spending is prudent:

> Although the failure of a single tie-cable will not generally lead to any customer interruptions, the failure of multiple tie cables could lead to a very large number of interruptions. The probability of two tie-cable outages occurring at the same time increases with the square of cable failure probability. If tie-cable failure rates increase by a factor of five, the probability of customer interruptions will increase by a factor of twenty-five. For this reason, deteriorated tie-cables at PG&E should be given a high priority for proactive replacement. (Exhibit PG&E-4, p. 18-39, para. 3.)

PG&E asserted that the amount of tie-cable that needs to be replaced is known and the cost to replace the cable is not disputed. PG&E contended that its request for $19.1 million is consistent with its 2005 recorded expenditures of $17.8 million. PG&E also stated that DRA's forecast represented only 61% of what PG&E spent in 2005 and 54% of what PG&E planned to spend in 2006.

iv. Plastic Insulated Cables

PG&E requested $13.875 million for capital expenditures in 2007 to replace plastic insulated cables. DRA proposed $5.074 million, for a difference of $8.801 million. DRA offered three reasons to support its forecast. First, DRA believes there is insufficient data on exactly when and where PG&E intends to replace plastic insulated cables. Second, the settlement reached in the Mission Substation Fire OII calls for a consultant's report on PG&E's system reliability, and this report may provide guidance on where funds should be spent. Finally, the most PG&E has ever spent on this activity is $4.630 million in 2003.

PG&E responded that it already knows, for the most part, when and where it will replace plastic insulated cable in 2007. PG&E also asserted that the consultant report from the Mission Substation OII is unlikely to provide new guidance as to where PG&E's capital expenditures should best be spent because (1) the report is limited to San Francisco, and (2) the study is not designed to analyze the optimization of plastic insulated cable replacement, but to identify ways to improve reliability overall.

PG&E disputed DRA's use of historical spending to forecast future capital expenditures in this area. PG&E asserted that two consultant reports found that PG&E needs to replace 300 to 400 miles of cable annually to maintain system reliability. PG&E's proposed expenditures, although large compared to historical spending, will replace less than 50 miles per year.

v. Lead Cables

PG&E requested $8.70 million for capital expenditures in 2007 to replace paper insulated lead covered cables (PILC). DRA proposed $2.03 million, for a difference of $6.67 million. DRA raised four arguments in support of its recommendation. First, PG&E needs more data to optimize expenditures. Second, a forthcoming consultant's report required by the Mission Substation Fire OII settlement will likely provide guidance as to where PG&E should make its capital investments. Third, lead cables are reliable. Finally, the largest amount PG&E has spent in this category was $1.83 million in 2004.

PG&E responded that historical expenditures in this area are not a good predictor of future requirements. Most PILC is at least 40 years old, and PILC failures have increased sevenfold in the last 20 years. PG&E believes the growing rate of failures shows a need for capital expenditures above historical levels, and that no additional data is needed to support these investments.

PG&E acknowledged that the consultant's report from the Mission Substation Fire OII might provide additional guidance as to where PG&E's capital expenditures for PILC replacement would be best spent. However, PG&E argued that it has already identified a great deal of work, and that the consultant's report could recommend an increase in expenditures.

vi. Other Electric Distribution Capital Expenditures

PG&E requested $6.6 million in 2007 to repair equipment. DRA proposed $4.7 million, for a difference of $1.9 million. DRA's proposal was equal to 2005 expenditures, and was based on a statement in PG&E's work papers that capital expenditures in this area would be static.

PG&E responded that the statement regarding a static level of capital expenditures was relative to PG&E's forecast of $6.65 million of capital spending in 2005 for repaired equipment. Actual spending in 2005 was lower than forecast because funds were shifted to higher priority work, such as new business and emergency response. PG&E states that lower spending on repaired equipment in 2005 does not mean there is less work, only that the work has been deferred.

b. Discussion

The Settlement Agreement provides PG&E with the full amount of its requested revenue requirement for Electric Distribution capital expenditures. Based on our review of the record, we are satisfied that the requested funding is needed to maintain, repair, upgrade, and expand PG&E's Electric Distribution system. We expect PG&E to use all the funds granted by today's Opinion for Electric Distribution capital expenditures for this purpose. If PG&E fails to do, it should provide a detailed explanation in its next GRC.

With this understanding, we find the uncontested Settlement outcome for Electric Distribution capital expenditures to be reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Electric Distribution Plant

PG&E forecasted $16.810 billion of weighted-average plant in 2007 for Electric Distribution Unbundled Costs Categories (UCCs).[68] DRA forecasted $16.754 billion, for a difference of $54 million. The Settlement adopts $16.808 billion. Other than the previously described issues concerning capital expenditures, there is no opposition to the Settlement outcome on this matter.

We find the Settlement result for Electric Distribution plant is reasonable in light of the record, consistent with applicable law, and in the public interest.

C. Gas Distribution

1. Gas Distribution Revenues

There were no disputes regarding PG&E's forecasts of gas customers, billings, sales, and 2007 Gas Distribution revenues at present rates. The Settlement Agreement adopts PG&E's forecasts. We concur with this uncontested outcome.

2. Gas Distribution O&M Expenses

PG&E requested $143 million for Gas Distribution O&M expenses in 2007. DRA and TURN proposed several disallowances. The Settlement adopts $140 million. The following table compares the Settlement outcome with PG&E's and DRA's litigation positions:

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[68] Electric Distribution UCCs include Wires and Services, Trans-Level Direct Connects, and Electric Public Purpose Program Administration.

Settlement Agreement re: Gas Distribution O&M Expenses ($ millions)							
	2006 Authorized	**Comparison Exhibit**		**Settlement**	**Variances Increase/(Decrease)**		
		PG&E	**DRA**		**Settlement vs. 2006**	**PG&E vs. Settlement**	**DRA vs. Settlement**
	(A)	**(B)**	**(C)**	**(D)**	**(D) - (A)**	**(D) - (B)**	**(D) - (C)**
O&M	138.8	142.5	133.0	139.9	1.0	(2.7)	6.9
Source: Settlement Agreement, Appendix B, Line 11.							

Below, we assess the reasonableness of the Settlement outcome for Gas Distribution O&M expenses in light of the record on the issues raised by DRA and TURN.

a. Issues Raised by DRA

DRA recommended that PG&E's requested expenses for Gas Distribution O&M in 2007 be reduced by $10.156 million. The bulk of DRA's proposed disallowance was in three areas: (1) $2.402 million for Field Service; (2) $3.544 million for Building Maintenance; and (3) $3.670 million for Customer Service Dispatch. These disallowances are addressed elsewhere in today's Opinion where we find the Settlement outcome for these matters is reasonable.[69]

[69] Field Service is subsumed within our consideration of Gas Field Service and Dispatch Operations expenses. Building Maintenance is subsumed within our consideration of Corporate Real Estate expenses. Customer Service Dispatch is subsumed within our consideration of Customer Services expenses.

b. Issues Raised by TURN

TURN recommends that the Settlement be modified to reduce funding for Gas Distribution O&M expenses in five areas.[70] We address each area below.

i. Mark and Locate

(A) Position of the Parties

PG&E is required by federal and state law to participate in regional "one-call" notification systems for planned excavation affecting underground utilities.[71] These one-call systems are commonly referred to as "USA," an acronym for underground service alert. Builders and others planning to excavate must call the USA at least two working days prior to excavating, and PG&E must provide information to the excavators within that two-working day period. PG&E informs the excavators about the location of PG&E's underground facilities, usually by having PG&E personnel visit the site, locate the underground pipes and wires, and place color-coded surface markings that show where the utilities are located (referred to as "Mark and Locate"). We address here PG&E's Mark & Locate expenses for both gas and electric distribution.

USA notifications, called "tags," are transmitted electronically to PG&E and processed by the Utility's ticket-handling software and mapping personnel. The following table shows USA tag volume since 1992:

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70 PG&E conceded $2.798 million (2007$) of additional disallowances of Gas Distribution O&M expenses recommended by TURN. (TURN comments on the Settlement Agreement, p. 41, Table 1.)

71 49 C.F.R. § 192.614 (2005) and Gov. Code § 4216.

Year	USA Tags	% Increase in USA Tags
1992	234,578	
1993	234,390	-0.1
1994	248,759	6.1
1995	263,002	5.7
1996	300,792	14.4
1997	356,371	18.5
1998	394,969	10.8
1999	442,325	12.0
2000	500,109	13.1
2001	508,237	1.6
2002	598,227	17.7
2003	663,325	10.9
2004	711,476	7.3

Source: Exhibit PG&E-4, Chapter 15, Table 1-4

The above Table shows that the number of tags increased by 9.4% annually during 2000 – 2004 and by 11.2% annually during 1995 – 2004. For 2005, PG&E forecasted a 20% decrease in units and an associated 27% increase in unit cost. The reduction in units is due to a change in California law[72] that increased the life of a USA tag from 14 to 28 days.

Prior to 2005, many tags were extended beyond the 14-calendar day period, which was counted as a new tag. Most of these extensions did not require PG&E to re-mark because the excavator had maintained the marks. The only work associated with these tags was the administrative processing. With the longer valid period, PG&E expects fewer tags, but a higher percentage of tags will require field work, which increases unit cost.

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72 Gov. Code § 4216. AB 1264.

After 2005, PG&E forecasts that USA tags will increase by 7% annually in 2006 and 2007, which is lower than the historic average, but similar to the 2004 increase. The net result is that PG&E expects to process 651,656 USA tags in 2007 at a total cost of $31.2 million.

TURN recommends that the Commission modify the Settlement Agreement to reduce Mark and Locate expenses by $1.201 million in 2007. TURN forecasts lower costs than PG&E because TURN believes the number of USA tags will grow by 4% annually during 2006 and 2007 compared to PG&E's forecast of 7% annual growth. TURN's forecast of lower growth is predicated on a slowdown of residential construction, which is one of the main drivers of PG&E's Mark & Locate expenses.

PG&E responds that its forecast is better than TURN's for five reasons: (1) TURN's proposed tag growth of 4% annually is less than historical growth; (2) PG&E's forecasted tag growth of 7% annually is conservative, as it is less than historical growth; (3) TURN's proposed growth rate is based on a small snap-shot in time, the first few months of 2006, which were an exceptionally rainy period making construction difficult; (4) PG&E's 2005 actual costs were 1.5% higher than PG&E's 2005 forecast in A.05-12-002; and (5) there will likely be an increase in tags because of proposed changes in California law designed to improve safety for excavators.

(B) Discussion

TURN forecasts 4% annual growth of USA tags during 2006 and 2007. PG&E forecasts 7% annual growth. PG&E acknowledges that residential construction is a significant driver of Mark & Locate expenses.[73] Official data shows that residential construction in California declined by 1.9% in 2005, the first decline since 1996.[74] Recent economic data show that the downturn in residential construction accelerated in 2006. In the first eight months of 2006 the pace of homebuilding in California was down nearly 16% from the same period in 2005.[75] Based on this data, we conclude that TURN's forecast of 4% annual growth in USA tags during 2006 and 2007 is more plausible than PG&E's forecast of 7% annual growth, and that TURN's forecast may actually be overly generous.

The information available for 2006 does not support PG&E's forecast of 7% annual tag growth in 2006 and 2007. During the first four months of 2006 there were 9% fewer tags than the comparable period for 2005.[76] PG&E submits that above-normal rain accounts for the reduced tags in 2006. It is true that the number of rain days during January-April 2006 was 27% higher than 2005.[77] However, TURN provided information which indicates that rain cannot account for this entire decrease in tags. PG&E's calculation of a 27% increase in rain days was based on the average of six weather stations over four months. TURN's review of the data shows that weather was drier at every weather station during February 2006 as compared to February 2005, with a total of 24 fewer rain days. Despite the drier weather, tags declined in February 2006 by 1.7% relative to

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[73] Exhibit PG&E-18, p. 23-7, Line 31.

[74] TURN comments filed on September 20, 2006, p. 44.

[75] California Department of Finance October 2006 monthly economic update. (http://www.dof.ca.gov/HTML/FINBULL/2006_FB/October/Oct06.asp) We take official notice of this economic data pursuant to Rule 13.9.

[76] Exhibit TURN-15.

[77] Exhibit TURN-15.

February 2005.[78] This information demonstrates that it is unlikely that rain accounts for the entire decrease in tags during the first four months of 2006. A more reasonable explanation is that the significant decrease in residential construction was a major factor in the reduction of tags.

PG&E contends that its forecast of 7% annual growth in tags in 2006 and 2007 is reasonable because there will likely be an increase in tags during the GRC cycle due to proposed changes in California state law. PG&E testified that Cal/OSHA and Senator Tolakson are working to introduce legislation that will improve safety for excavators by requiring more excavators to call to have underground facilities located and marked prior to excavating.[79]

PG&E's anticipation of new legislation is not a reasonable basis for finding that PG&E will have 7% annual growth in tags during 2006 and 2007. We conclude for the preceding reasons that TURN's forecast of 4% annual growth of tags during this period is reasonable and may even be too high.

The Settling Parties maintain that TURN's proposed disallowance of $1.201 million is reflected in the Settlement outcome for Gas Distribution O&M expenses. The Settlement provides $140 million for Gas Distribution O&M expense in 2007, which is $3 million less than PG&E's request of $143 million and $7 million more than DRA's recommendation.

Almost all of the difference between PG&E and DRA was in three areas: (1) DRA's proposed disallowance of $2.4 million for gas service representative staff levels; (2) DRA's proposed disallowance of $3.7 million for a software upgrade to PG&E's Field Automation System (FAS); and (3) DRA's proposed

[78] TURN comments dated September 20, 2006, pp. 43-44.

[79] Exhibit PG&E-18, p. 23-8.

disallowance of $3.5 million for several PG&E's projects to rehabilitate and renovate real estate facilities.[80] After reviewing the record on these issues, we find the Settlement outcome of providing PG&E with $3 million less than it requested is reasonably close to how we would have decided the three disallowances proposed by DRA and all of TURN's proposed disallowances for Gas Distribution O&M expenses, including TURN's proposed reduction of $1.201 million for Mark & Locate.[81] We address TURN's other proposed disallowances of Gas Distribution O&M expenses below.

For the preceding reasons, we conclude that the Settlement outcome for Mark & Locate expenses is reasonable in light of the whole record, consistent with applicable law, and in the public interest. Therefore, we decline to adopt TURN's proposal to modify the Settlement Agreement on this matter.

ii. Leak Survey

(A) Position of the Parties

PG&E requested $6.271 million for Leak Survey expenses in 2007. DRA did not contest PG&E's request. TURN recommends a disallowance of $0.157 million. The reason for the difference between PG&E's and TURN's positions is that TURN proposes a 9% increase in Leak Survey expenses in 2007 compared to 2004, which is less that PG&E's requested 12% increase. TURN's escalation rate is based on recorded costs for 2000-2005, while PG&E's escalation rate is based on the 10-year average growth rate of 1.3% in the number of miles

[80] PG&E email to service list on November 22, 2006.

[81] For example, it is likely that we would have granted PG&E's full requests for (i) FAS software upgrade, and (ii) building seismic retrofits and upgrades.

surveyed. TURN believes its approach is superior because PG&E's Leak Survey costs were mostly declining during 2000-2005.

PG&E responds that TURN's ignores the main driver of the long-term growth in these expenses, namely, the growth in PG&E's gas distribution system.

(B) Discussion

We find TURN's forecast for Leak Survey expenses in 2007 to be markedly better than PG&E's. As noted by TURN, PG&E's forecast of $6.271 million is out of line with its actual expenses during 2000-2005, which were as follows:

PG&E Leak Survey Expenses ($millions)							
2000 Actual	**2001 Actual**	**2002 Actual**	**2003 Actual**	**2004 Actual**	**2005 Actual**	**2006 Forecast**	**2007 Forecast**
5.965	5.848	5.665	6.033	5.610	5.651	6.075	6.271
Source: Exhibits TURN-13 and TURN-14							

PG&E's forecast of $6.271 million for Leak Survey expenses is 11% higher than 2005. We agree with TURN's observation that PG&E's forecasted increase is excessive in light of PG&E's generally flat to declining expenses during 2000-2005. TURN's proposed increase of 9% for Leak Survey expenses in 2007 compared to 2004 (which exceeded 2005) is reasonable, if not generous.

Although we agree with the general merits of TURN's position, we decline to modify the Settlement Agreement to reduce funding for Leak Survey expenses in 2007 by $0.157 million. The Settlement provides $140 million for Gas Distribution O&M expense in 2007, which is $3 million less than PG&E requested. The Settling Parties represent that the Settlement outcome takes into consideration TURN's position on Leak Survey expenses. We conclude that because TURN's proposed disallowance of $0.157 million for Leak Survey expenses is small compared to the Settlement Agreement's reduction of $3 million for Gas Distribution expenses, it is reasonable to assume that TURN's disallowance is reflected in the Settlement. Based on this assumption, we find the Settlement outcome for Leak Survey expenses is reasonable in light of the whole record, consistent with the law, and in the public interest.

iii. Operate Gas Systems

(A) Position of the Parties

PG&E's Operate Gas System (OGS) activities include (1) monitoring system pressures, flows, odorant levels, (2) operating valves and regulator stations, and (3) adjusting gas flow rates in response to demand. PG&E requested $3.3 million expenses for OGS in 2007.

TURN recommends a disallowance of $0.135 million in 2007 because OGS costs generally declined during 2000-2005. PG&E responds that TURN's proposal ignores inflation and system growth. PG&E also contends that its efforts to drive down costs in 2000-2004 should not be used to deny recovery of future cost increases that are driven by inflation and system growth.

(B) Discussion

We generally agree with TURN that PG&E's forecast of OGS costs in 2007 is too high in relation to its recorded costs. PG&E's recorded and forecast costs for OGS are as follows:

($000)						
2000 Recorded	**2001 Recorded**	**2002 Recorded**	**2003 Recorded**	**2004 Recorded**	**2005 Recorded**	**2007 Forecast**
2,566	2,764	3,143	2,888	2,666	2,680	3,257
Source: Exhibit TURN-16						

We are not persuaded by PG&E that OGS costs will be 21.5% higher in 2007 compared to 2005. Likewise, we are not convinced by PG&E's argument that its successful efforts to constrain OGS costs during 2000-2005 cannot be continued in 2007.

Although we agree with the general merits of TURN's position, we decline to adopt its proposal to modify the Settlement Agreement to reduce OGS expenses in 2007 by $0.135 million. The Settling Parties agree that the revenue requirement for OGS is subsumed within the Settlement outcome for Gas Distribution O&M expenses. The Settlement provides $140 million for gas distribution operations expense in 2007, which is $3 million less than PG&E's request of $143 million. The Settling Parties further agree that the Settlement outcome takes into consideration TURN's position on OGS expenses. We conclude that because TURN's proposed adjustment of $0.135 million for OGS is small in relation to the Settlement Agreement's overall reduction of $3 million for gas distribution expenses, it is reasonable to assume that TURN's proposed adjustment is reflected in the Settlement Agreement. Based on this assumption, we find that the Settlement outcome for OGS expenses is reasonable in light of the whole record, consistent with the law, and in the public interest.

iv. Corrective Maintenance

(A) Position of the Parties

Corrective maintenance consists of repairing and replacing damaged or failed facilities. PG&E requested $19.266 million for corrective maintenance expenses in 2007.

TURN proposes that funding for corrective maintenance be reduced by $0.539 million based on historical costs during 2000-2005. TURN contends that its reduction is reasonable in light of lower unit costs in 2005.

PG&E responds that its forecast of 2007 expenses, which was based on 2004 recorded costs inflated by the ten-year average increase of 1.3%, is reasonable because (1) it is only 5% higher than 2004 recorded costs; (2) TURN's estimate ignores circumstances that drove down PG&E's unit costs in 2005, and which will not recur 2007; and (3) the 2005 data used by TURN does not reflect the fluctuating nature of corrective maintenance costs.

(B) Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to reduce funding for corrective maintenance by $0.539 million. PG&E's recorded and forecasted costs for corrective maintenance are as follows:

($000)							
2000 Recorded	**2001 Recorded**	**2002 Recorded**	**2003 Recorded**	**2004 Recorded**	**2005 Recorded**	**2006 Forecast**	**2007 Forecast**
20,505	20,900	19,883	17,912	18,312	18,288	18,715	19,266
Source: Exhibit TURN-17							

PG&E's forecast of 2007 expenses is based on 2004 recorded costs inflated by the ten-year average annual increase of 1.3%. The result is that 2007 forecasted costs are 5.2% higher than 2004 recorded costs, and less than recorded costs in 2000, 2001, and 2002. We conclude that this outcome is reasonable.

TURN argues that we should reduce PG&E's requested expenses in 2007 because PG&E forecasts that unit costs will be higher in 2007 compared to 2005. While there is some merit to TURN's position, other historical measures of costs discussed in the previous paragraph demonstrate that PG&E's forecast for 2007 is reasonable.

v. Meter Protection Program

(A) Position of the Parties

The purpose of PG&E's Meter Protection Program (MPP) is to correct gas meter installations that do not conform to Federal safety regulations. The program encompasses approximately 400,000 meter locations that are to be inspected and modified, as necessary, between 1990 and 2016. At the end of 2004, PG&E had inspected all 400,000 locations, found that approximately 107,000 meters required corrective action, had corrected approximately 66,000 meters, and had roughly 41,000 meters awaiting corrective action.

PG&E requested $3.246 million for MPP expenses in 2007. PG&E's request was based on the remaining scope of the program, the program schedule, and unit costs. TURN recommends that the Commission modify the Settlement Agreement to reduce funding for the MPP in 2007 by $0.359 million. TURN's proposal is based on the three-year average of expenses in 2003-2005 escalated by 5% to reflect more expensive work.

PG&E responds that unit costs in 2007 will exceed the historical average recommended by TURN because of (1) labor and material escalation, and (2) changes in the scope of work. In 2004, approximately 30% of the locations with inaccessible service valves were resolved by raising valve boxes instead of installing new valves. PG&E anticipates higher unit costs in 2007 and beyond as the easy-to-fix locations are depleted.

PG&E contends that TURN's use of a three-year average is flawed for several reasons. First, the MPP is driven by Department of Transportation and California Fire Code requirements. In order to achieve the goals of the program on schedule, PG&E must adhere to the forecasts in its testimony. Second, PG&E has finalized the scope of this program, resulting in a more accurate forecast.

Finally, over the three-year period used by TURN (2003-2005), PG&E's expenditures exceeded its 2003 GRC forecast by 8%, demonstrating PG&E's commitment to finishing this program on schedule in 2016.

(B) Discussion

We decline to adopt TURN's proposal to reduce funding for the MPP by $0.359 million. The MPP is a vital public safety program, and we want to ensure that it is fully funded. Given the importance of the MPP to public safety, we expect PG&E to utilize all of the $3.246 million of annual funding provided by today's Opinion for the MPP for that purpose only. If PG&E fails to do, it should provide a detailed explanation in its next GRC.

c. Conclusion

Based on our review of the record, we conclude for the preceding reasons that the Settlement outcome for Gas Distribution O&M expenses is reasonable in light of the record, consistent with applicable law, and in the public interest.

3. Gas Distribution Capital Expenditures

PG&E requested $205.0 million for Gas Distribution capital expenditures in 2007. DRA recommended $193.9 million, for a difference of $11.1 million. No other parties addressed this matter. The following table compares PG&E's and DRA's litigation positions on Gas Distribution capital expenditures:

2007 GRC Comparison Gas Distribution Capital Expenditures by Functional Groups ($000)				
	2007 Capital Expenditures			
Description	**PG&E**	**DRA**	**PG&E > DRA**	**% Difference**
Gas Pipeline Replacement Program	68,353	59,562	8,791	12.9%
Gas Meter Protection-Capital	695	695	0	0.0%
Gas Dist. Customer Connects	59,783	59,783	0	0.0%
Gas Dist. New Capacity – Gas	11,182	11,182	0	0.0%
Gas Dist. Reliability	15,767	13,423	2,344	14.9%
Gas Dist. Work Requested by Other	18,093	18,093	0	0.0%
Gas Dist. Emergency Response	203	203	0	0.0%
Gas Meters	30,918	30,918	0	0.0%
Total	**204,995**	**193,860**	**11,135**	**5.7%**
Source: Exhibit PG&E-79, p. D-2				

The Settlement Agreement adopts PG&E's requested Gas Distribution capital expenditures of $205.6 million.[82]

Below, we assess the reasonableness of the Settlement outcome for Gas Distribution capital expenditures in light of the record on the issues raised by DRA.

a. Summary of the Record

i. Gas Pipeline Replacement Program

PG&E requested $66.953 million in 2007 for Gas Pipeline Replacement Program (GPRP) capital expenditures. DRA recommended $59.562 million, for a

[82] The Settlement Agreement inadvertently incorporates PG&E's requested capital expenditures of $31.542 million for gas meters in 2007 when the Settling Parties agreed to DRA's recommended amount of $30.918 million. We will reflect the lower DRA amount in the revenue requirement and rate base adopted by today's Opinion.

difference of $7.391 million. Subsequently, PG&E and the Disability Rights Advocates agreed to a Memorandum of Understanding (MOU), which increased PG&E's 2007 request for the GPRP by $1.4 million to $68.353 million. There is no opposition to the MOU, which is addressed elsewhere in today's Opinion.

PG&E's request for GPRP capital expenditures in 2007 was based on the remaining scope of the program, PG&E's schedule commitment to the Commission, and pipe replacement costs. PG&E contended that its requested funding would allow PG&E to complete the remaining 250 miles of the highest risk pipe in PG&E's system by 2009 for all areas outside of San Francisco, and by 2014 for San Francisco. DRA's forecast for 2007 was based on the inflation-adjusted average of recorded expenditures during 2003-2005 and the ratio of historical budgeted expenditures to actual expenditures.

ii. Gas Reliability

PG&E requested $15.767 million in 2007 for capital expenditures to maintain and enhance the reliability of its Gas Distribution infrastructure. DRA recommended $13.423 million, for a difference of $2.344 million. PG&E's request was based on historical expenditures and known future projects. DRA used a 4-year, inflation-adjusted average to determine its 2007 forecast.

b. Discussion

The Settlement Agreement provides PG&E with the full amount of its requested capital expenditures for Gas Distribution. The bulk of the difference between PG&E's request and DRA's proposal pertains to GPRP, where PG&E requested, and the Settlement adopts, $7.391 million more than DRA recommended. The amount provided by the Settlement for GPRP capital spending is well above the historical four-year average adjusted for inflation.

The GPRP is a high-priority program that affects public safety and the reliability of PG&E's Gas Distribution system. We conclude that it is reasonable for the Settlement to provide substantially increased funding for this program, provided that PG&E actually spends these funds on the GPRP.[83] Therefore, we will approve the Settlement outcome for Gas Distribution capital expenditures with the condition that PG&E uses all the funds provided by the Settlement for the GPRP for this purpose. If PG&E fails to do, it should provide a detailed explanation in its next GRC. Absent a compelling explanation, we may impose a disallowance similar to the deferred-maintenance disallowance addressed elsewhere in today's Opinion.

With this condition, we find the Settlement outcome for Gas Distribution capital expenditures to be reasonable in light of the record, consistent with applicable law, and in the public interest.

4. Gas Distribution Plant

PG&E forecasted $6.049 billion of weighted-average plant-in-service in 2007 for Gas Distribution UCCs.[84] DRA proposed $6.028 billion, for a difference of $21 million. The Settling Parties agree to $6.048 billion, effectively adopting PG&E's forecast. There is no opposition to the Settlement on this matter.

We find that the uncontested Settlement outcome for Gas Distribution plant-in-service is reasonable in light of the whole record, consistent with applicable law, and in the public interest.

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83 PG&E's actual expenditures for the GPRP have sometimes fallen short of budgeted expenditures. (Exhibit DRA 15, p. 15-5, Table 15-3.)

84 Gas Distribution (GD) UCCs include GD Pipes and Services, GD Gas Procurement Administration, and GD Gas Public Purpose Program Administration.

D. Electric Generation

1. Generation Revenues

There were no disputes regarding PG&E's forecasts of Electric Generation billings, sales, and 2007 revenues at present rates. The Settlement Agreement adopts PG&E's forecasts. We concur with this uncontested outcome.

2. Generation O&M Expenses

PG&E requested $457 million in 2007 for Generation O&M expenses. DRA recommended $406 million, for a difference of $51 million. The Settlement adopts $451 million, which is $6 million less than PG&E requested and $45 million more than DRA recommended.

a. Hydro Operations

PG&E has 68 hydro powerhouses located on 16 rivers and four tributaries of the Sierra Nevada, Cascade, and Coastal mountain ranges. The generating capacity of PG&E's Hydro system is 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 128 miles of canals and flumes, 135 miles of tunnels, 19 miles of pipe, 5 miles of natural waterways, and approximately 140,000 acres of fee-owned land. The Hydro system operates under 26 FERC licenses, 92 water right licenses, and 160 Statements of Water Diversion and Use.

PG&E requested $143.9 million for Hydro O&M expenses in 2007, an increase of 42.3% over 2004 recorded expenses. PG&E's request was based on actual 2004 expenses, approved budgets for 2005, recommended budgets for 2006, and long-term plans for 2007. PG&E testified that the increased expenses in 2007 are due to higher maintenance costs for aging Hydro assets and significantly higher regulatory compliance costs for new FERC licenses, new environmental and safety regulations, and increased regulatory fees.

DRA recommended $108.6 million for Hydro O&M expenses in 2007, or $35.3 million less than PG&E requested. Aglet and TURN proposed disallowances of $32.1 million and $7.91 million, respectively.

The Settling Parties agree that the resolution of all issues regarding PG&E's revenue requirement for Hydro O&M expenses is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides $450.6 million for Generation O&M expenses in 2007, which is $6.4 million less than PG&E requested.

Below, we assess the reasonableness of Settlement outcome for Hydro O&M expenses in light of the record on the issues raised by the parties.

i. Issues Raised by DRA

DRA recommended $108.6 million for Hydro O&M expenses in 2007, or $35.3 million less than PG&E requested. DRA's recommendation was based on the three-year average of Hydro O&M expenses during 2003 - 2005.

PG&E responded that DRA's reliance on historical information was inappropriate because it failed to capture significantly higher regulatory compliance costs associated with new FERC license conditions, new environmental and safety regulations, and regulatory fees.

Based on our review of the record, we find that PG&E has demonstrated that its Hydro O&M expenses will be significantly higher in 2007 compared to historical levels, primarily because of costly new conditions that are now being routinely attached to new and amended hydro licenses issued by FERC. Therefore, we conclude that the Settlement outcome for Hydro O&M expenses is reasonable in light of the record on the issues raised by DRA.

ii. Issues Raised by Aglet and TURN

(A) Forecasted Hydro O&M Expenses for 2007

(1) Position of the Parties

Aglet recommends $111.9 million for Hydro O&M expenses in 2007, or $32.1 million less than PG&E requested. Aglet's recommendation is based on a linear trend of recorded and budgeted costs from 1998 through 2006, extrapolated to 2007. Aglet believes that reliance on historical data to forecast Hydro O&M costs in 2007 is reasonable because (1) there is no new Hydro plant that requires additional O&M expenses, (2) the observed trend of slowly increasing costs should cover increased operational needs, and (3) PG&E's requested Hydro O&M expenses are simply too far above historical levels. Aglet also identified the following "soft spots" in PG&E's work papers:

- FERC issued a new license for Rock Creek-Cresta in 2001, but implementation expenses jump from zero to $698,000 in 2006.
- The costs for several projects rise dramatically, but FERC has not yet issued new licenses or licenses amendments for these projects, and the license conditions are uncertain.
- Bucks Creek Article 103 implementation costs spike in 2007, but the timing of such costs is uncertain.
- Costs at Helms for venting transformer cases and installing blast walls look more like capital projects than expenses.
- Hiring and training costs are relatively flat during 2005 - 2009, but the number of new hires declines from 13 in 2005 to 3 in 2008.
- Canal system improvements and flume repair costs rise from zero in 2006 to more than $4 million in 2009, but repair needs for waterways that are 50 to 100 years old should be stable.
- Dam repair costs rise from zero in 2006 to more than $3.3 million in 2009, but the listed activities are illustrative only.

- Lead paint and PCB monitoring and abatement costs rise from zero in 2005 to $1 million in 2009, but PG&E has not shown any rise in associated hazards.
- Miscellaneous safety costs rise by a factor of seven beginning in 2007, but PG&E has not shown any rise in safety risks.

Aglet states that the above projects have some justification, but they look like a wish list. All told, Aglet finds that PG&E has not shown with clear and convincing evidence that a large increase is Hydro O&M expenses is necessary.

PG&E responds that Aglet's use of historical data to forecast Hydro O&M expenses fails to capture significantly higher regulatory, environmental, and safety compliance expenses. For example, compliance costs grew by 73% between 2003 and 2006. This was due primarily to the greatly expanded scope of FERC license conditions for six new licenses received between 2001 and 2003. PG&E's forecasted increase in 2007 assumes there will be a similar increase in compliance costs for five new licenses and two major license amendments that PG&E expects to receive by then.

Although some licenses have been delayed since PG&E filed A.05-12-002, thereby deferring some expenses, PG&E testified that it will incur costs for two projects in 2007 that were not included in its forecast of 2007 O&M expenses -- one project to clear and repair rock movement at the Belden project, and second project for a seismic upgrade of the Crane Valley Dam.

(2) Discussion

Aglet proposes to use historical data to forecast Hydro O&M expenses in 2007 rather than PG&E's project-based forecast. We find PG&E's approach to be superior to Aglet's. PG&E testified that all of the forecasted projects are cost effective and/or required for legal, safety, or other reasons. Aglet did not attempt to show with substantive evidence that any particular project is not necessary, cost effective, or beneficial. PG&E's forecast also reflects the dramatic increases in regulatory, environmental, and safety compliance costs in recent years, and PG&E testified that such costs will continue to increase as PG&E receives new and amended FERC licenses.[85] In contrast, Aglet relies on historical data that does not capture the significant increases in compliance costs that PG&E has testified will drive Hydro O&M expenses in 2007.

For the preceding reasons, we find that PG&E has demonstrated with clear and convincing evidence that the Settlement outcome for Hydro O&M expenses in 2007 with respect to the issues raised by Aglet is reasonable in light of the record. Accordingly, we decline to adopt Aglet's proposal to reduce funding for Hydro O&M expenses.

(B) Delayed Projects

(1) Position of the Parties

TURN proposes that the Commission modify the Settlement Agreement to reduce Hydro O&M expenses in 2007 by $1.94 million for delayed projects. The basis for TURN's proposal is a PG&E data response wherein PG&E admits that some of the regulatory compliance costs it forecast for 2007 may be deferred because of delays in the issuance of new FERC licenses and license amendments.

PG&E acknowledges that some regulatory compliance costs may be deferred because of the delays identified by TURN. PG&E contends, however, that the deferred costs will be offset by expenses for two unforeseen projects -- one project to clear and repair rock movement at the Belden project, and second project for a seismic upgrade of the Crane Valley Dam

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[85] Exhibit PG&E-3, pp. 3-24 to 3-35.

TURN urges the Commission to reject PG&E's argument that the reduction of regulatory compliance costs in 2007 is offset by two new projects that were not included in PG&E's forecast. TURN argues that the cost and timing of the unforeseen projects is vague and, therefore, should not be used as justification for allowing recovery of $1.94 million of deferred regulatory compliance costs.

(2) Discussion

We decline to adopt TURN's proposal to modify the Settlement Agreement to remove $1.94 million for projects that have been postponed because of delays in the issuance of new FERC licenses and license amendments. PG&E will clearly incur these costs, it is only a question of when. We conclude that because PG&E's license applications have been pending at FERC for some time,[86] it is likely that FERC will issue the new licenses and license amendments sometime during the GRC cycle. Adopting TURN's proposal would effectively deny PG&E the ability to recover some or all of the regulatory compliance costs for these new licenses and amendments. Such a result would be unfair to PG&E and contrary to the public interest, since there is no question that these costs are reasonable and necessary.

Although there will be some reduction in PG&E's regulatory compliance costs in 2007 because of the delay in the issuance of new and amended licenses, we are persuaded that the reduction in costs will be more than offset by other costs that PG&E will incur in 2007 and subsequent years for two unforeseen projects.[87] These projects are (1) $10 million for safety-related work to address

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[86] Exhibit PG&E-3, p. 3-24, L:20-23.

[87] The Settlement Agreement provides PG&E with less money than it requested for Generation O&M expenses. The time-value-of-money savings that accrue from the

Footnote continued on next page.

rock movement at the Belden project, and (2) $5-7 million for a seismic upgrade of the Crane Valley Dam.[88] PG&E will have to absorb the associated costs under the revenue requirement provided by the Settlement Agreement.

This is an important point for test-year ratemaking and the Commission's consideration of the Settlement. PG&E prepared its forecast of costs in 2007 with the information that was available to PG&E in 2005. Actual costs in 2007 and subsequent years of the GRC cycle will likely be higher and lower across the range of cost categories. The central issue is whether the Settlement Agreement contains a reasonable forecast of PG&E's regulatory compliance costs in 2007 and subsequent years. We find that it does for the preceding reasons.

(C) Regulatory Fees

(1) Position of the Parties

TURN raised two issues regarding Hydro-related regulatory fees. The first issue concerns PG&E's request for $5.13 million of "other regulatory fees" (OR fees) in 2007. TURN opposes PG&E's request.

PG&E's requested OR fees consist of two components. The first is $2 million for fees levied pursuant to the Endangered Species Act (ESA) for habitat restoration at the Upper North Fork Feather River (UNFFR) project. TURN states that the project has been postponed and that PG&E has admitted that the forecast of $2 million is speculative. TURN argues that PG&E has not demonstrated with convincing evidence that it will incur ESA fees in 2007.

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deferral of $1.94 million of Regulatory Compliance costs is captured, at least to some degree, in the Settlement's reduction of Generation O&M expenses.

[88] 13 RT 1001:1-28, PG&E/Sweeney.

The second component is $3.2 million that PG&E estimates it will pay to CALFED in 2007 to finance the Bay-Delta Program Ecosystem Restoration Program. TURN states that PG&E's forecast is based on (1) a draft report issued by CALFED in 2005, and (2) one of three possible methods identified in the draft report for calculating the fee. TURN asserts that PG&E does not know when CALFED will finalize the method for calculating the fee or begin collecting the fee. This demonstrates, according to TURN, that there is no basis whatsoever for allowing PG&E to recover CALFED fees.

The second issued raised by TURN regarding regulatory fees pertains to PG&E's request for $2.757 million in 2007 for FERC Other Federal Agency (OFA) fees. TURN provided a PG&E data response wherein PG&E admitted that OFA fees are an "estimated liability" that might never be paid to the government:

> Since 2003 FERC has not required licensees to actually pay the annual OFA fees. FERC provided each licensee with an estimated OFA fee liability for each licensed project in 2003. FERC has not indicated conclusively what the final OFA fee liability might be for 2003 or subsequent years. FERC may also decide to charge licensees for prior year OFA fees that it partially refunded. PG&E has continued to accrue an estimated liability amount to cover potential OFA fee charges. (Exhibit TURN-24.)

TURN recommends that the Commission either (1) adopt balancing account treatment for OFA fees, or (2) modify the Settlement to eliminate the entire $2.757 million that PG&E requested for OFA fees in 2007.

PG&E responds that it expects to incur all of the forecasted regulatory fees in 2007. PG&E argues that although its forecast might be imperfect, that does not make its forecast unreasonable.

(2) Discussion

We are persuaded that it is more likely than not that PG&E will incur some level of OR Fees and OFA fees at some point during the GRC cycle. Therefore, we decline to adopt TURN's proposal to remove all funding for these fees from the Settlement Agreement.

We are also persuaded by TURN that PG&E's forecast of OR fees and OFA fees is subject to considerable uncertainty. For example, the OFA fees have not been paid since 2003, and TURN demonstrated through cross examination of PG&E's witness that PG&E does not know if it will pay all the fees as estimated, only a portion of the fees, or no fees at all.[89]

Even though there is some uncertainty surrounding the amount of regulatory fees that PG&E will ultimately pay, we will not adopt TURN's proposed balancing account for OFA fees. Instead, in its next GRC, PG&E shall report on the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and provide a forecast of future OR and OFA costs based on its actual payment history.

(D) Deferred Maintenance

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement Agreement to exclude $0.791 million for lead paint and PCB abatement expenses. PG&E requested and received funding for these expenses in its 2003 GRC, and now requests funding a second time for lead paint and PCB abatement.

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[89] 13 RT 998, 22-26, Sweeney, PG&E.

TURN calls PG&E's request a classic example of deferred maintenance. It arises when a utility seeks money for a specific maintenance activity, does not perform the maintenance, and then seeks money again for the same maintenance activity, thereby requesting to be paid twice. TURN opines that excluding deferred maintenance from rates is vital to the integrity of test-year ratemaking.

TURN cites several Commission decisions that denied ratepayer funding for deferred maintenance. For example, in D.00-02-046 the Commission held:

> It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. (D.00-02-046, Conclusion of Law 15, *mimeo.,* p. 536.)

More recently, the Commission disallowed $1.4 million in annual expenses and $3.4 million in capital costs that SCE requested for deferred pole maintenance, stating that "ratepayers should not be required to pay twice for the same authorized expense.[90]"

PG&E responds that it will not be paid twice. This is because PG&E's actual expenditures for environmental remediation work exceeded the 2003 GRC forecast. As shown in the following table, increased costs for other remediation work more than offset the under-run for lead paint and PCB abatement.

[90] D.04-07-044, *mimeo.*, pp. 105, 108-110.

(Millions of Dollars)

Lead Paint and PCB Abatement	2003	2004	2005	Total
2003 GRC Forecast	1.6	1.6	1.3	4.5
Actual	0.8	0.6	0.7	2.1
Under Spent	0.8	1.0	0.6	2.4
Environmental Compliance				
2003 GRC Forecast	8.8	11.2	10.0	30.0
Actual	9.6	12.3	11.4	33.3
Over Spent	(0.8)	(1.1)	(1.4)	(3.3)
Total Over Spent	**0.0**	**(0.1)**	**(0.8)**	**(0.9)**

PG&E argues that under TURN's reasoning, PG&E would have no discretion to reschedule work to reflect changing priorities. This reasoning would require that all work be performed as estimated or PG&E would never be allowed to recover the cost of the work.

(2) Discussion

The Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past.[91] Here, there is no dispute that PG&E received funding for lead paint and PCB abatement in its prior GRC proceeding, and that PG&E seeks funding for these activities a second time in the current proceeding.

The Settlement Parties state that the issue of funding for lead paint and PCB abatement is subsumed in the Settlement outcome for Generation O&M

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91 D.04-07-044, *mimeo.,* pp. 105, 108-110; D.00-02-046, COL 15.

expenses.[92] The Settlement provides $450.6 million for Generation O&M expenses in 2007, which is $6.4 million less than PG&E requested.

In order to find that the Settlement Agreement is consistent with the law, which includes adherence to long-established Commission precedent, we must be satisfied that all of PG&E's lead paint and PCB abatement costs are excluded from the O&M expenses adopted by the Settlement. We conclude that the $6.4 million reduction to O&M expenses adopted by the Settlement is sufficiently large to accommodate a 100% disallowance of $0.791 million for lead paint and PCB abatement. Based on this conclusion, we find that the Settlement outcome is reasonable in light of the record, consistent with long-established Commission precedent, and in the public interest.

b. Nuclear Operations

PG&E's Diablo Canyon nuclear power plant has two generation units with a combined capacity of 2,200 megawatts (MW). PG&E requested $310.8 million for Nuclear O&M expenses in 2007. DRA recommended $295.6 million, which was $15.2 million less than PG&E requested. Aglet, TURN, and ANR/SC proposed additional disallowances.

The Settling Parties agree that the resolution of issues regarding Nuclear O&M costs is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides $450.6 million for Generation O&M expenses in 2007, which is $6.4 million less than PG&E requested.

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92 Settlement Motion, p. 87.

Below, we assess the reasonableness of the Settlement outcome for Nuclear O&M expenses in light of the record for the issues raised by DRA, Aglet, TURN, and ANR/SC.

i. Issues Raised by the Parties

(A) New Information System and Pump

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement to reduce PG&E's Nuclear O&M expenses in 2007 by $1.2 million to reflect projected O&M savings from PG&E's planned capital expenditures for a new Plant Management Information System (PIMS) and a new, more efficient pump. Otherwise, ratepayers will fund the capital expenditures but receive none of the benefits.

PG&E responds that the O&M expense savings were reflected in its GRC application in the form of avoided costs (i.e., costs that would not be incurred and, therefore, not requested).

(2) Discussion

We find that PG&E has affirmatively demonstrated through clear and convincing evidence that the O&M expense savings from PIMs and the new pump are reflected in PG&E's application (and the Settlement Agreement) in the form of avoided costs.[93] Therefore, we decline to adopt TURN's recommendation.

(B) License Renewal Feasibility Study

Diablo Canyon operates pursuant to two licenses issued by the NRC that expire in 2024 (Unit 1) and 2025 (Unit 2). PG&E's request for Nuclear O&M

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[93] 29 RT 2751:20-21, PG&E/Becker. See also Exhibit TURN-62.

expenses included $16.8 million spread over 2007-2009 for a license renewal feasibility study. The purpose of the study is to analyze Diablo Canyon equipment and operations to determine whether to apply to the NRC for a 20-year extension of the two Diablo Canyon licenses.

DRA opposed funding for the license renewal feasibility study on the grounds that it is premature. ANR/SC and TURN opposed the feasibility study for the same reason and others. The Settling Parties agree that funding for the study is subsumed in the Settlement outcome for Generation O&M expenses. The Settlement Agreement provides $450.6 million for Generation O&M expenses in 2007, which is $6.4 million less than PG&E requested and $44.3 million more than DRA recommended.[94]

(1) Position of the Parties

ANR/SC and TURN recommend that the Commission modify the Settlement Agreement to remove $16.8 million for the Diablo Canyon license renewal feasibility study. TURN alternatively proposes that the $16.8 million be deferred as a regulatory asset that (1) accrues interest at the rate that applies to the allowance for funds used during construction (AFUDC), and (2) is amortized over the life of the renewed licenses beginning in 2024.

ANR/SC and TURN contend that it is premature to fund a study that will be competed in 2009, which is 15 years before the first NRC license expires in 2024. They believe that a study completed in 2009 will be irrelevant to circumstances in 2024. As such, the study will be a waste of ratepayers' money.

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[94] Settlement, para. 17 and Appendix G, L. 19.

ANR/SC and TURN provide several examples of PG&E's record of vastly underestimating the future cost of operating Diablo Canyon and overestimating the service life of major power plant components and systems. Given this poor track record, they believe the Commission and the public can have little confidence that PG&E's license renewal study will be of any value in deciding whether to renew the licenses 15 years after the study is completed.

Another reason ANR/SC and TURN believe the study is premature is the recent enactment of Assembly Bill (AB) 1632.[95] This statute requires the California Energy Commission (CEC) to review the potential impacts of aging, seismic events, and nuclear waste accumulation at existing nuclear power plants.[96] ANR/SC and TURN believe the CEC's review, which is scheduled to be completed in 2008, will shape the State's policy on nuclear re-licensing. ANR/SC and TURN contend there is no point in ratepayers funding PG&E's study prior to the completion the CEC's study.

ANR/SC and TURN are particularly concerned that PG&E may use the license renewal study to unilaterally seek license renewal without prior Commission review of the study or Commission authority for PG&E to submit a re-licensing application. They state that there are many factors that must be considered before deciding whether to proceed with re-licensing. These factors include the ongoing accumulation of high-level nuclear waste at Diablo Canyon, the ever rising cost of nuclear power, and the Commission's evolving energy procurement policies.

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95 Statutes of 2006, Chapter 722.

96 PRC § 25303(a)(8), (c).

PG&E responds that it is prudent to perform the license renewal feasibility study at this time in order to develop the factual and regulatory information needed to decide whether to apply for license renewal. The scope of the study would include (1) screening Diablo Canyon's structures, systems, and components to determine if they are within the scope of a renewed license; (2) performing an aging analysis of the in-scope systems and components to determine the need for additional monitoring programs; and (3) preparing a draft environmental impact report.

PG&E offers several other reasons why it is appropriate to conduct the license renewal feasibility study at this time. First, PG&E's witness testified that:

> [t]he license renewal feasibility study will lead us to make a very important decision, which is whether or not to pursue license renewal at Diablo Canyon. The time frame for making that decision would be around the end of this general rate case…or roughly 15 years before the licenses expire…If we were not -- when that time came and we were to make that very important decision not to proceed with license renewal after considering all the issues, the costs, et cetera, then we need and the state of California needs time to plan for replacement power for Diablo Canyon. (Tr. 2767:8-24, PG&E/Becker.)

Second, doing the study now takes advantage of the fact that the NRC is staffed and has processes in place to consider license renewal applications because several other utilities have already decided to pursue license renewals.

Finally, performing the study now will enable PG&E to address any needed changes to plant structures, systems, and equipment to enable an additional 20 years of operations. PG&E testified:

> The sooner we know that, the sooner we can make the changes, and the sooner the benefit would occur. And that

> benefit would show up in plant reliability, in safety margins, et cetera. (Tr. 2768:8-20, PG&E/Becker.)

PG&E contends that ANR/SC's and TURN's proposal to deny funding for the study is short-sighted. Diablo Canyon provides 2,200 MW of base-load capacity that would require a considerable amount of time, planning, and investment to replace. Performing the study now will allow PG&E, and the Commission, to determine in the next five years whether to apply to the NRC for license renewal – a time frame that allows PG&E and the Commission to make alternative plans to replace Diablo Canyon's 2,200 MW of capacity should the decision be made to forgo license renewal.

PG&E opposes TURN's proposal to capitalize the costs of the study as a regulatory asset that accrues AFUDC and to amortize the regulatory asset over the term of the renewed licenses. PG&E believes that project costs should not be capitalized until it is decided that a project will be pursued. PG&E has not yet decided whether to pursue renewal of the Diablo Canyon licenses. When PG&E makes that decision, PG&E will begin to capitalize the project costs.

(2) Discussion

PG&E's proposed Diablo Canyon license renewable feasibility study will be completed in 2009, which is 15 to 16 years before the expiration of the current licenses. Ratepayers should fund the study only if 15-16 years of lead time is needed to decide if Diablo Canyon should be closed and, if so, to replace the 2,200 MW of base load capacity provided by Diablo Canyon.

California currently plans for long-term power procurement through the Commission's biennial adoption of a rolling 10-year long-term procurement plan (LTPP). Given the large amount of base load capacity provided by Diablo Canyon, we conclude that it is prudent to know 10 years in advance if 2,200 MW of capacity will need to be replaced so that replacement capacity can be obtained in an orderly, cost effective, and timely manner.

TURN's comments on the Proposed Decision state that there is no need for 10 years of advance notice to plan for 2,200 MW of replacement capacity. In D.06-11-048, the Commission approved PG&E's application to acquire 2,250 MW of new generation capacity by mid-2010. This shows, according to TURN, that PG&E can acquire replacement capacity for Diablo Canyon in 4-5 years.

TURN overlooks the fact that the 2,250 MW of capacity was part of PG&E's first 10-year LTPP approved by D.04-12-048. The purpose of the LTPP is to identify resource needs a decade in advance in order to provide sufficient time to plan for, and procure, new capacity in an orderly and cost effective manner. While TURN evidently believes there is no need for long-term planning, we believe it would be reckless and gambling with the public interest to wait until only 4-5 years are left before the Diablo Canyon licenses expire to decide whether there is a need to acquire 2,200 MW of replacement capacity. The safer and more prudent course of action is to endeavor to know 10 years in advance if the large amount of power provided by Diablo Canyon will need to be replaced.

The LTPP is issued in even numbered years and is based on a long-term forecast of electricity supply and demand contained in the biennial Integrated Energy Policy Report (IEPR) that is issued by the CEC in the previous odd-numbered year.[97] We presume that in order to be incorporated into the IEPR, a final decision to forgo license renewal (and the accompanying need to procure 2,200 MW of base load capacity) would need to be made six to 12 months prior to

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97 D.04-12-048, *mimeo.*, pp. 165-167 and COL 42, pp. 235-36.

the CEC's issuance of its IEPR. That means approximately 12 years of lead time is needed to acquire replacement power once a final decision is made not to pursue license renewal.

The decision on whether to forgo license renewal should be made in a Commission proceeding or other appropriate venue. We anticipate that such a proceeding would be complex and contentious, but could still be completed within one year. That means a completed license renewal feasibility study should be submitted to the Commission for review approximately 13 years prior to license expiration, or in the year 2011.

Pursuant to the Settlement Agreement adopted by today's Opinion, PG&E's forthcoming GRC cycle will end in December 2010. We cannot wait until the GRC cycle beginning in 2011 to fund a license renewal study because doing so would delay the completion of the study until the end of 2012, assuming it took two years to prepare the study. We conclude, therefore, that it is reasonable to fund the study during 2007-2010 so that the study will be available for the Commission's review in 2011, and the results of the study incorporated into the LTPP issued in 2014.

For the preceding reasons, we find the Settlement Agreement's provisions that authorize $16.8 million for the Diablo Canyon license renewal feasibility study to be reasonable and in the public interest. As noted by ANR/SC and TURN, AB 1632 requires the CEC to assess key policy and planning issues affecting the future role of nuclear power plants in the State. The statute requires the CEC to issue its assessment by November 1, 2008. PG&E shall incorporate the CEC's AB 1632 assessment into its license renewal study. To avoid unnecessary duplication and overlap with the CEC's study, PG&E should defer to the extent feasible its work on its own study, and associated spending, until after the CEC issues its findings and conclusions. PG&E should incorporate the findings and recommendations of the CEC study in its own work.

We will require PG&E to submit by no later than June 30, 2011, an application on whether to pursue license renewal. The application shall include PG&E's license renewal study and shall address (1) whether renewal of the licenses is cost effective and in the best interests of PG&E's ratepayers, (2) the CEC's AB 1632 assessment, and (3) any legislative framework that may be established for reviewing the costs and benefits of license renewal.[98] As stated previously, it is our intent that the proceeding in 2011 will result in a decision on whether to pursue license renewal based on circumstances at that time, and that the results of the proceeding will be incorporated into the CEC's 2013 IEPR and the Commission's 2014 LTPP.

ANR/SC and TURN contend that it is premature to fund a study that will be competed approximately 15 years before the first license expires in 2024. For the reasons stated previously, we believe it is prudent to have a completed study in hand 13 years prior to license expiration. Funding the study in the 2007-1010 GRC cycle will provide 13 years of lead time.

ANR/SC and TURN maintain that because PG&E has a poor record of forecasting the cost of operating Diablo Canyon and the life of major power-plant components, there can be little confidence that PG&E's study will be of any value in deciding whether to renew a license 15 years after the study is completed. We agree that the cost of operating Diablo Canyon over the years has consistently exceeded PG&E's forecasts. That does not mean, however, that there is no need

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[98] The CEC's 2005 IEPR urges the Legislature to establish a framework to review license renewal costs and benefits. (2005 IEPR, p. 4.)

for a license renewal feasibility study. The issue raised by ANR/SC and TURN goes to the merits of the study results, which cannot be judged until the study is submitted to the Commission for review. There will be ample opportunity at that time for the parties to review and litigate the contents of the study.

ANR/SC and TURN are concerned that PG&E may use the study to unilaterally seek license renewal. We have already addressed this concern by requiring PG&E to submit the study to the Commission as part of an application in 2011 on whether to proceed with license renewal. If PG&E fails to do so, we agree with PG&E's observation that the Commission "has ample means to deal with PG&E's failure to comply with the Commission's order to file an application, if that should ever come to pass.[99]"

TURN alternatively proposes that the cost of the license renewal study be deferred as a regulatory asset and amortized over the term of the renewed licenses. TURN's proposal is consistent with the USOA. The instructions for Account 183 state, in relevant part, as follows:

> This account shall be charged with all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation. If construction results, this account shall be credited and the appropriate utility plant account charged. If the work is abandoned, the charge shall be made to Account 426.5, Other Deductions, or to the appropriate operating expense account.

It makes sense to defer current expenditures for feasibility studies when a decision will be made within one or two years on whether to proceed with the

99 PG&E opening comments on the Alternate Proposed Decision, p. 23.

project being contemplated and the project starts soon thereafter. That is not the case here. Adopting TURN's proposal could defer cost recovery until 2024, during which time the deferred costs would accrue interest based on PG&E's authorized rate of return, currently 8.79% pre-tax.[100] The $16.8 million of deferred costs at the end of 2009 would balloon to $60.2 million by the end of 2024 based on a compound annual escalation of 8.79%. The growth of the deferred costs would exceed inflation, thereby making ratepayers worse off with each passing year. We conclude that ratepayers will be better off to pay $16.8 million during the forthcoming GRC cycle rather than a significantly higher amount in the future.

For the preceding reasons, we decline to adopt TURN's alternative proposal to defer recovery of the study costs.

(C) Additional Staffing

PG&E requested $3 million in 2007 to address its aging workforce at Diablo Canyon by hiring and training an additional 10 engineers, 12 operators, and 15 utility workers. DRA opposed the staffing increase. DRA contended that PG&E had neither performed a cost-effectiveness study for its additional staffing proposal, nor asserted that it was safety-related or an NRC mandate.

PG&E responded that the aging workforce at Diablo Canyon is a serious issue. The average age of Diablo Canyon employees is 47.6 years. In five years, 42% of the employees at Diablo Canyon will be eligible for retirement. To replace its aging workforce.

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[100] Settlement Agreement, Appendix G, Table 1-2, Line 33. AFUDC is not grossed up for taxes.

The Settling Parties agree that the resolution of issues regarding funding for additional staff at Diablo Canyon is subsumed in the Settlement outcome for Generation expenses. No party disputed the Settlement outcome on this matter.

We conclude that the uncontested Settlement outcome regarding additional staffing for Diablo Canyon is reasonable in light of the record, consistent with applicable law, and in the public interest.

(D) NEI Membership Dues

PG&E's forecast of Nuclear O&M expenses in 2007 included $772,000 for membership in the Nuclear Energy Institute (NEI).[101] TURN proposed a 50% disallowance of NEI membership fees because part of NEI's function is to advocate for nuclear power. TURN's proposal was consistent with the Commission's decision in the recent SCE GRC proceeding where the Commission reduced SCE's request for NEI membership fees by 50%. However, the Commission left open the possibility of 100% recovery of NEI fees in the future, but directed SCE to demonstrate exactly what portion of the NEI membership fee, if any, is used for the advocacy of nuclear power.[102]

The Settling Parties agree that the Settlement outcome for Generation O&M expenses includes recovery of only 50% of NEI dues. In its next GRC, PG&E will present more detailed documentation supporting 100% recovery of NEI fees.[103] There was no opposition to the Settlement outcome for NEI dues.

We find the uncontested Settlement outcome for NEI funding is reasonable in light of the record, consistent with applicable law, and in the public interest.

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[101] Exhibit TURN-1, p. 9.

[102] D.06-05-015, *mimeo*., pp. 34-36.

[103] Settlement Motion, pp. 91-92.

ii. Fossil Operations

PG&E's Fossil operations currently consist of four generating units at the Humboldt Bay power plant (HBPP) that have a combined capacity of 135 MW. PG&E requested $11.8 million for Fossil Generation O&M expenses in 2007 for the continued operation of the existing units at HBPP until new generation units come online in 2009. DRA did not oppose PG&E's request.

The Settling Parties agree that the resolution of issues regarding Fossil Generation O&M expenses is subsumed within the Settlement outcome for all Generation O&M expenses.[104] The Settlement also provides a one-way balancing account for certain specified HBPP costs that PG&E may be able to avoid depending on the timing of the HBPP re-power project.[105] The re-power project will replace four steam generators with ten 16.3 MW gas-fired generators. The on-line target for the new generators is May 2009.

(A) Issues Raised by TURN

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement to reduce Fossil Generation O&M expenses by $2.58 million. TURN's disallowance has four components. First, TURN notes that PG&E requested $0.6 million for boiler recertification costs in test-year 2007. Because these costs are built into the test year, PG&E will recover these costs in each of the attrition years. TURN states

[104] Settlement Agreement, para. 17.

[105] The Settlement establishes a "memorandum account" to track the authorized and actual revenue requirement for specified projects for the existing generation facilities at HBPP. The estimated revenue requirement for these projects in 2007, 2008, and 2009 is $1.3 million, $0.9 million, $0.7 million, respectively. In the event it is not necessary to perform these projects, PG&E will refund any over collection in the next GRC. (Settlement Agreement, para. 30.)

that boiler recertifications are scheduled for 2007 and 2009, but not for 2008. TURN argues that PG&E should not be allowed to collect revenues for boiler recertification in 2008 when no recertification will occur that year.

Second, TURN states that PG&E has admitted that there will be no need for boiler recertification in 2009 if the HBPP re-power project is completed in 2009. In light of these facts, TURN recommends a disallowance of boiler recertification costs for 2009.

Third, PG&E requested $1.455 million for expenses in 2007 and 2008 to plan for Clean Water Act § 361(b) cooling water intake regulations. The Settlement Agreement provides for the tracking of these costs in the HBPP memorandum account. TURN believes that most of these costs may not materialize due to PG&E's plan to re-power HBPP in 2009, and recommends that the Commission not allow recovery of these costs at the present time. Instead, PG&E should track its actual expenses in the HBPP balancing account and recoup these expenses in the next GRC if required.

Finally, TURN notes that the costs of special projects for HBPP that are tracked in PG&E's internal account MWC CJ - Fossil Generation Projects. None of these costs are included in the proposed HBPP memorandum account. Again, TURN believes that most of these costs may not materialize due to PG&E's plan to re-power HBPP in 2009. TURN states that PG&E should be allowed to track in the HBPP balancing account the actual expenses for MWC CJ in 2009 and recoup these expenses in the next GRC if required. Otherwise, PG&E may collect revenues for costs that it might never incur.

PG&E opposes TURN's proposed disallowance. PG&E argues that it is speculative to assume that it will not incur forecasted costs for the existing generation units at HBPP because PG&E has not yet obtained the necessary permits or set a construction schedule for re-powering HBPP. Until then, PG&E believes it is prudent to proceed under the assumption that the existing generation units at HBPP will continue to operate through the GRC cycle.

PG&E generally agrees that balancing account treatment is appropriate for costs that can be avoided due to the planned re-powering of HBPP. However, PG&E opposes balancing account treatment for any expenses and capital expenditures that are not earmarked for such treatment by the Settlement.

(2) Discussion

TURN asserts that the Settlement Agreement is unreasonable because it allows PG&E to recover overstated and avoidable costs for HBPP. We agree in part and disagree in part.

We agree with TURN that PG&E's requested revenue requirement for HBPP inappropriately included $0.6 million for boiler recertification costs in 2008, even though there will be no recertification that year. However, we disagree with TURN that the Settlement allows PG&E to recover boiler recertification costs for the year 2008. The Settlement Agreement reduces PG&E's requested O&M costs for Generation by $6.4 million.[106] The Settling Parties represent that the agreed-upon amount of O&M costs reflects consideration of TURN's position. Based on this representation, we conclude that the improper boiler recertification costs for 2008 are included in the Settlement's $6.4 million reduction to PG&E's requested O&M costs.

Regarding the remainder of TURN's proposed disallowance, TURN is correct that some forecasted O&M expenses for the current units at HBPP may be

[106] Settlement Agreement, para. 17.

avoided if HBPP is re-powered in 2009 as PG&E anticipates. However, the avoided O&M expenses for the retired units will be offset, at least to some extent, by O&M expenses for the new units. TURN made no effort to show there will be a net reduction of PG&E's O&M expenses from the HBPP re-powering project. Absent such a showing, we decline to adopt TURN's proposed disallowance of HBPP O&M expenses or TURN's proposed tracking of HBPP O&M expenses for the existing facilities.

On a related matter, we note that the Settlement Agreement does not specify the means that PG&E will use to establish the HBPP balancing account. We will direct PG&E to file an advice letter to establish the one-way balancing account within 30 days from the effective date of today's Opinion. The account balance shall accrue interest at the rate on prime, three month commercial paper as reported in Federal Reserve Statistical Release H-15. The Commission's Energy Division may approve the advice letter without a Commission resolution if the advice letter complies with the requirements of today's Opinion.

iii. Electric Supply Administration

PG&E requested $42.3 million for Electric Supply Administration (ESA) expenses in 2007 to plan for and acquire electric supply-side and demand-side resources. DRA proposed $38.0 million, for a difference of $4.3 million. DRA's proposal was based on its belief that PG&E would reach adequate staffing levels by 2006. PG&E responded that it needs more staff in 2007 compared to 2006 because its electric procurement activities continue to expand and increase in complexity. The resolution of DRA's proposed disallowance is subsumed in the broader Settlement outcome for Generation O&M expenses.

(A) Issues Raised by TURN

(1) Position of the Parties

TURN recommends that the Commission modify the Settlement Agreement to reduce ESA expenses by $5.2 million in 2007. TURN asserts that PG&E's requested revenue requirement for ESA is a padded wish list. Rather than granting the wish list, TURN proposes that the Commission escalate PG&E's 2006 budget for ESA forward into 2007.

TURN provides several examples of "questionable items" to support its proposal. First, TURN claims that PG&E does not need four new staff positions for electric fuels management because (1) PG&E recently signed a settlement agreement that provides fixed prices for certain Qualifying Facilities (QFs), and (2) PG&E's new gas-fired plants will not be operational until 2008-2010.

Second, TURN believes a delay in the transition to geographic pricing for transmission indicates that two staff may not be required for all of 2007.

Third, TURN suggests that the reduction of PG&E's payments to QFs from twice per month to once per month pursuant to D.05-09-003 eliminates the need for one staff position.

Fourth, TURN argues that PG&E does not need three new staff positions in power settlements due to declining workloads for the FERC refund proceeding, refund negotiations with suppliers, and bankruptcy issues with Power Exchange (PX) and California Independent System Operator (CAISO) suppliers. TURN believes these activities will be substantially completed by 2007 and certainly before the end of the GRC cycle.

Fifth, TURN believes that PG&E might double collect its costs for one-half staff position assigned to Community Choice Aggregation (CCA). TURN claims these costs will be charged to the Aggregators. Thus, PG&E is poised to collect the money twice – once from the Aggregators and a second time from ratepayers.

Sixth, TURN states that PG&E seeks to add one staff position in 2008 for AMI. This is inappropriate, according to TURN, because AMI-related costs are supposed to be excluded from this GRC.

Seventh, TURN contends that PG&E's request to recover costs for an Independent Evaluator of renewable solicitations is inconsistent with D.06-05-039 and Resolution E-3914.[107] TURN recommends that such costs be removed from this GRC and recorded in the Long Term Procurement Memorandum Account (LTPMA) in accordance with D.06-05-039 and Resolution E-3914.

Finally, TURN asserts that PG&E's request to increase staffing for long-term resource procurement from 12 to 30 positions is unsupported. TURN notes that PG&E needed only 12 staff positions to conduct its recent acquisition of Contra Costa 8 (CC8) simultaneously with major renewable and non-renewable solicitations. TURN submits that PG&E has not identified an increase in future workload relative to recent activity.

PG&E responds that TURN's proposed reduction of $5.2 million is based on budgeted expenses for ESA in 2006. PG&E states that it is inappropriate to use the 2006 budget to forecast expenses in 2007 because of changed circumstances in 2007. PG&E also provided a point-by-point rebuttal to each of the arguments raised by TURN in support of its proposal.

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[107] Resolution E-3914 was issued on April 21, 2005.

(2) Discussion

TURN recommends that the Commission modify the Settlement to reduce funding for ESA by $5.2 million in 2007. TURN supports its recommendation with eight "questionable items" that purport to show that PG&E's revenue requirement is too high. For the reasons set forth below, we find that the "questionable items" do not justify a modification of the Settlement Agreement.

First, TURN suggests that PG&E's request for four new staff for electric fuels management is excessive because (1) PG&E has signed a QF settlement agreement that should reduce PG&E's exposure to volatile gas prices, and (2) PG&E's new gas-fired power plants will not be online until 2008-2010. In response, PG&E testified that the items cited by TURN will not affect PG&E's workload. This is because PG&E expects a substantial increase in gas planning, trading, and scheduling activities for new QF gas tolling agreements. And although PG&E's new gas-fired units will not come online until 2008 - 2010, PG&E testified that it will begin making long-term gas supply, transportation, storage, and hedging arrangements for these units in 2007.[108] For example, PG&E will hold requests for offers for long-term gas supply and gas storage during 2007; negotiate gas transportation agreements with gas pipelines in 2007; and begin hedging the gas positions for the new facilities in 2007.

Second, TURN doubts the need for two additional staff in 2007 to work on the CAISO Market Redesign (CMR). Because CMR has been delayed until November 2007, TURN believes the staff may not be required for all of 2007. In response, PG&E testified that although CMR has been delayed, much work needs to be done to prepare for CMR implementation. For example, PG&E will

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[108] Exhibit PG&E-18, p. 13-3.

participate in simulations for the "new" market at the same time that it manages daily trading activities in the existing market. Market simulations will occur in the first, second and third quarters of 2007 according to the current ISO schedule, and the latter two will involve 24x7 simulations. Staff will need to be hired and trained in the new market processes prior to the November 2007 rollout.[109]

Third, TURN suggests that a decrease in the number of payments to QFs (from two to one per month) could reduce staffing by one position. In response, PG&E testified that issuing payments is a minor factor in determining staffing needs. The steps preceding payment still need to be performed even though the number of payments will be reduced. For example, the QF meter data must be validated prior to issuing payment, and the same meter data must be submitted to the CAISO for market settlement purposes following the CAISO tariff timelines. PG&E represents that the work and timelines associated with these processes has not diminished. Moreover, PG&E represents that the reduced number of QF payments was anticipated when PG&E prepared its GRC request and was reflected in PG&E's overall staffing request.[110]

Fourth, TURN believes that PG&E can reduce staffing by three positions due to reduced workload for the FERC refund proceeding, refund negotiations with suppliers, and bankruptcy issues with suppliers. In response, PG&E testified there are still many issues before FERC and on appeal. Additionally, claims in PG&E's bankruptcy proceeding are still open because they are tied to the outcome of the FERC refund proceeding and global settlements. PG&E represents that none of this work will end until the conclusion of the FERC

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[109] Exhibit PG&E-18, pp. 13-3 to 13-4.

[110] Exhibit PG&E-18, p. 13-4.

refund proceeding, including rehearings and appeals. PG&E cannot predict when the FERC refund proceeding will end.

Fifth, PG&E requested one-half staff position for CCA-related activities. TURN asserts that PG&E will be charging Aggregators for this work, and that including it in this GRC is double-counting. PG&E testified, however, that it only charges Aggregators for work that is directly attributable to a specific Aggregator. The one-half staff position would be responsible for maintaining the software and databases required to offer CCA service, which is not directly attributable to a particular Aggregators. PG&E represents that the Commission requires utilities to recover such costs from all customers.[111]

Sixth, PG&E seeks one staff position in ESA for AMI. TURN is concerned that PG&E is double counting AMI costs in the instant GRC proceeding and the AMI proceeding. However, the Settlement Agreement states that (1) the only area where PG&E presented costs in both the GRC and the AMI proceedings is Information Technology (IT),[112] and (2) PG&E removed the duplicative IT costs from its GRC request, as shown in Appendix G of the Comparison Exhibit.[113] TURN provided no evidence to rebut the Settlement Agreement.

Seventh, TURN contends that PG&E's request to recover costs for an Independent Evaluator for renewable solicitations is inconsistent with D.06-05-039 and Resolution E-3914. However, PG&E correctly observes that Resolution E-3914 granted PG&E's request to establish the LTPMA because PG&E would incur costs for new long-term procurement activities in 2005 and

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111 Exhibit PG&E-18, pp. 13-5 to 13-6.

112 Settlement Agreement, para. 51.

113 Exhibit PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.

2006 that were not included in its GRC revenue requirement.[114] In approving the LTPMA, the Commission held that the GRC is the appropriate place to recover long-term procurement costs, stating:

> SCE included its long-term procurement costs in its [GRC] revenue requirement request. While the Commission has yet to decide on the merits of SCE's request, the fact that SCE has included the long-term procurement cost in its GRC request would indicate an unequal treatment should PG&E's request to establish a memorandum account to track these costs be denied. That is, PG&E did not have an opportunity to present its long-term procurement costs for consideration by the Commission while SCE did have that opportunity. Simply because PG&E's GRC was completed before SCE's should not prevent PG&E from receiving the same opportunity to present its case. (Resolution E-3914, p. 5.)

The above statement in Resolution E-3914 indicates that the LTPMA was meant to bridge the gap between GRCs, i.e., to provide PG&E an opportunity to track and recover costs incurred in 2005 and 2006 that would have been included in PG&E's previous GRC. After 2006, costs for the Independent Evaluator are appropriately recovered through the GRC process.[115]

Finally, TURN argues that PG&E's request to increase staffing for long-term procurement from 12 to 30 is unsupported. TURN is correct that PG&E

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[114] Settling Parties' reply comments filed Oct. 5, 2006, pp. 45-47.

[115] Resolution E-3914 states at p. 2 that PG&E's Advice Letter 2597-E requested authority to recover costs incurred through 2006 for long-term resource procurement via the LTPMA, and to recover costs incurred in 2007 and beyond in PG&E's next GRC application. Resolution E-3914 approves PG&E's request, with certain modifications. (Resolution E-3914-E, Ordering Paragraph 1.) The Resolution does not modify PG&E's request to recover costs for long-term procurement in 2007 and beyond in the instant GRC proceeding.

managed the CC8 and Long-Term Request for Offer (LT RFO) solicitation with fewer staff members than it is requesting for 2007. However, PG&E testified that although the long-term contracts mentioned above are executed, there is still much work to do in 2007 to bring these resources online, including regulatory, permitting, engineering, construction, and community outreach. PG&E represents that it cannot continue to work on the existing transactions (i.e., CC8 and seven long-term contracts resulting from PG&E's LT RFO solicitation) and future procurement processes and transactions with the existing staff.[116]

For the preceding reasons, we conclude that the Settlement Agreement provisions related to ESA are reasonable in light of the record.

c. Conclusion

Based on our review of the record, we conclude that the Settlement Agreement provisions regarding Generation O&M expenses are reasonable in light of the record, consistent with the law, and in the public interest.

3. Generation Capital Expenditures

PG&E requested funding for $241.4 million of Generation capital expenditures in 2007, a 30% increase over 2004. By business unit, PG&E's capital expenditure request was:

Hydro: $103.6 million.

Nuclear: $134.4 million.

Fossil: $3.4 million for the Humboldt Bay Power Plant.

DRA recommended that PG&E's requested capital expenditures be reduced by $29.1 million. Other parties proposed additional reductions. The

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[116] Exhibit PG&E-18, p. 13-6.

Settlement Agreement adopts PG&E's position in full. Below, we assess the reasonableness of the Settlement outcome for Generation capital expenditures in light of the record on the issues raised by DRA and other parities.

a. Hydro Capital Expenditures

PG&E requested $103.6 million for Hydro capital expenditures in 2007, and increase of 76.2% from 2004. PG&E testified that the primary drivers of Hydro capital expenditures are (1) new license conditions; (2) reliability projects to maintain and replace aging assets; (3) dam safety modifications in response to increasingly stringent regulations; and (4) automation and efficiency projects to increase the power provided by the existing water supply.

DRA opposed $1.4 million that was requested by PG&E to replace the failed penstock at Coal Canyon. DRA recommended that PG&E present an analysis of the benefits of retaining Coal Canyon versus decommissioning. PG&E responded that retaining the Coal Canyon powerhouse is the least-cost alternative if downstream water users pay a fair share of the cost to rebuild and maintain the water conveyance system. PG&E also agreed to file an application with the Commission to modify the water contract with Cal Water Services.

The Settling Parties agree that the resolution of the previously described issue is subsumed in the Settlement outcome for Generation capital additions.[117] Table 3-7 in Appendix G of the Settlement Agreement shows that the Settlement adopts PG&E's position on Hydro capital expenditures in 2007.

We find the Settlement outcome for the issues raised by DRA is reasonable in light of the record, consistent with the law, and in the public interest.

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[117] Settlement, para. 27.

i. Issues Raised by Aglet and TURN

(A) Position of the Parties

Aglet recommends that the Commission adopt Hydro capital expenditures of $79.1 million in 2007 based on a linear trend of recorded and budgeted costs from 1998 to 2004, extrapolated to 2007. Alternatively, Aglet recommends $82.5 million based on a three-year average of PG&E's data for 2004 - 2006.

Aglet observes that PG&E's requested capital expenditures for Hydro Generation represent an increase of 76.2% over three years. PG&E has asked for the moon, according to Aglet, without credible supporting evidence.

Aglet observes that much of PG&E's request is for re-licensing conditions. However, the timing of these expenditures is uncertain due to delays in the issuance of FERC licenses. PG&E also admits that some Hydro capital spending is "catch up" after years of limited investment due to bankruptcy and divestiture. Aglet contends that the Commission should not use catch-up spending as a basis to set rates.

Aglet urges the Commission to ignore PG&E's testimony during cross examination that the deferral of costs for delayed projects is offset by other costs for unforeseen projects that were not included in PG&E's request. Aglet states that it did not have an opportunity to test the reasonableness of such projects. It is too late for PG&E to amend its showing on Hydro projects, according to Aglet.

TURN recommends a $12 million reduction to PG&E's Hydro plant-in-service in 2007. TURN represents that PG&E's forecast of 2007 plant-in-service assumed $24 million of capital expenditures through 2006 to comply with FERC re-licensing conditions for the Upper North Feather River and Poe projects. However, these projects have been delayed, and PG&E currently expects re-licensing to occur in 2007. TURN estimates that both of these projects will be re-licensed in mid-2007. Thus, rather than being in rate base for all of 2007 as PG&E originally forecast, the $24 million would be added rate base in mid-2007, resulting in a weighted-average reduction to rate base of $12 million in 2007.

PG&E opposes Aglet's proposal to use historical data to forecast Hydro capital expenditures in 2007. PG&E contends that the use of historical information is not useful when, as here, future conditions will be significantly different than historical circumstances.

PG&E likewise opposes TURN's proposal to reduce Hydro plant-in-service because of FERC delays in issuing hydro licenses. PG&E asserts that the FERC delays do not translate into a month-for-month delay in capital spending.

ii. Discussion

Aglet proposes to use historical data to forecast Hydro capital expenditures in 2007 rather than PG&E's project-based forecast adopted by the Settlement Agreement. We find PG&E's approach to be superior to Aglet's. PG&E testified that all of the forecasted projects are cost effective and/or required for legal, safety, or other reasons. Aglet did not attempt to show that any particular project is not necessary, cost effective, or beneficial. Thus, we have no reason to question the reasonableness of the projects. In contrast to PG&E's project-specific forecast, Aglet relies on historical data that does not reflect the regulatory and operational requirements that PG&E has testified will drive Hydro capital expenditures in 2007.

TURN recommends that the Commission reduce Hydro plant-in-service by $12 million due to FERC's delay in renewing licenses for Hydro facilities. We decline to modify the Settlement on this basis. Although TURN has demonstrated that some capital expenditures will be postponed, there is no dispute that all capital spending for the delayed projects will be completed during 2007. PG&E testified that the postponed capital spending will be offset, at least in part, by (1) higher AFUDC accruing on previous capital expenditures for the delayed projects,[118] and (2) capital expenditures for new, safety-related projects that were not forecast by PG&E.[119]

Aglet urges the Commission to give no weight to PG&E's testimony that it will incur capital expenditures for projects that were not included in PG&E's request. We disagree. PG&E provided its testimony in response to a cross examination exhibit from TURN.[120] The cross-examination exhibit, which forms the basis for TURN's proposal to reduce Hydro plant-in-service by $12 million in 2007, contains information that apparently came to light after PG&E submitted its forecast of 2007 plant-in-service.[121] It would be unfair to prohibit PG&E from rebutting TURN's cross-examination exhibit as Aglet proposes. If TURN is allowed to use more recent information to discredit PG&E's showing, it is only fair that PG&E should be allowed to do the same to rehabilitate its showing.

For the preceding reasons, we conclude that PG&E has demonstrated with clear and convincing evidence that the Settlement outcome for Hydro capital expenditures is reasonable in light of the record, consistent with the law, and in the public interest.

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[118] 13 RT 964:25-965:5 and 967:12-14, PG&E/Sweeney.

[119] The unanticipated capital expenditures include up to $10 million to repair rock movement at the Beldon project and $5 - $7 million for seismic work at the Crane Valley Dam. (13 RT 1001:16-27, PG&E/Sweeney.)

[120] 13 RT 1001:16-27, PG&E/Sweeney.

[121] Exhibit TURN-24, PG&E Response to DR 28-1; 13 RT 958-972, PG&E/Sweeney.

b. Nuclear Capital Expenditures

PG&E requested $134.4 million for Nuclear capital expenditures in 2007. Aglet, ANR/SC, and TURN proposed several disallowances. DRA recommended that the Commission address in another proceeding PG&E's proposal to replace the reactor vessel heads.

The Settling Parties agree that the resolution of all issues regarding Nuclear capital expenditures is subsumed in the Settlement outcome for Generation capital additions.[122] The Settlement adopts PG&E's request for $195.0 million of weighted-average capital additions for Generation in 2007.[123]

Below, we consider the reasonableness of the Settlement outcome in light of the record on the issues raised by the parties.

i. Issues Raised by the Parties

(A) Nuclear Core Plant Work

(1) Position of the Parties

PG&E requested $36.2 million in 2007 for capital expenditures for Nuclear Core Plant Work. Aglet observes that PG&E's requested expenditures in 2007 are nearly ten times higher than its recorded expenditures of $3.8 million in 2004. The only support in PG&E's application for dramatically higher capital spending in 2007 is a list of seven project titles.

PG&E's rebuttal testimony offered nine "Examples of 2007 capital projects" and a list of requested capital expenditures. Aglet states there is no narrative explanation or work papers supporting the list. The total 2007 capital

[122] Settlement Motion, p. 101; Settlement Agreement, para. 27.

[123] Settlement Agreement, Appendix G, Table 3-7, Line 24.

expenditures for the nine projects is $11.7 million, less than one third of the requested capital expenditures of $36.2 million.

Aglet contends that a listing of project titles and a brief explanation of $11.7 million of the requested spending is insufficient support for $36.2 million of capital expenditures. Further, Aglet notes that none of the capital projects listed by PG&E is critical, which leads Aglet to believe that some of the projects might not be funded depending on the availability of funds.

Aglet proposes that the Commission approve $13.1 million for Core Plant Work capital expenditures in 2007. Aglet's proposal is based on the three-year average of recorded and forecasted capital expenditures for 2004, 2005, and 2006.

PG&E responds that it has adequately identified the specific projects for its requested capital expenditures for Core Plant Work. PG&E argues that it is not appropriate to rely on historical information as recommended by Aglet when better, project-specific information has been presented.

(2) Discussion

PG&E requested $36.2 million for Core Plant Work capital expenditures in 2007. The Settlement Agreement adopts PG&E's request. To support its request, PG&E provided (1) a list of over 200 capital projects that comprise its requested capital expenditures, and (2) a description of nine of the projects with associated capital expenditures of $11.7 million.[124] All of the projects identified by PG&E appear to be necessary and useful to the provision of utility service.

Aglet asserts that PG&E failed to support its requested capital expenditures. We disagree. PG&E provided a detailed breakdown of its

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[124] Exhibit PG&E-18, pp. 11-10 to 11-12 and Table 11-1.

requested capital expenditures for Core Plant Work. Aglet did not attempt to demonstrate that any particular project is unreasonable or would not be undertaken by PG&E. Absent such a showing, we decline to adopt Aglet's proposal to reduce capital spending for Core Plant Work by nearly two thirds. Instead, we find that PG&E has demonstrated with substantial, clear, and convincing evidence that the Settlement outcome for nuclear Core Plant Work is reasonable in light of the record.

Although we decline to adopt Aglet's recommendation, we share Aglet's concern about the dramatic increase in capital expenditures for Core Plant Work since 2004. As noted by Aglet, the Settlement provides $36.2 million for Core Plant Work capital expenditures in 2007, which far exceeds PG&E's recorded expenditures of $3.8 million in 2004. Further, all of the projects are ranked as less-than-critical in PG&E's project-priority ranking system.

The high level of capital expenditures provided by the Settlement relative to historic spending, combined with funding for less-than-critical projects, indicates that PG&E has some flexibility as to whether it will actually use all the funds provided by the Settlement for Core Plant Work. We invite parties in the next GRC proceeding to closely scrutinize PG&E's capital spending for Core Plant Work during 2007-2010 to determine whether PG&E spent all the capital funds authorized by today's Opinion for the 200-plus capital projects for Core Plant Work listed in Chapter 11 of Exhibit PG&E-18. If PG&E has not, we do not anticipate authorizing capital expenditures for these projects a second time unless PG&E can demonstrate that it had to divert funds to other Core Plant Work not listed in Exhibit PG&E-18.

(B) Radioactive Waste Storage Facility

(1) Position of the Parties

Diablo Canyon's spent nuclear fuel is currently stored on site in large pools of water. The storage capacity of the pools is nearly exhausted. To allow Diablo Canyon to operate past 2010, PG&E is currently building an independent spent fuel storage facility (ISFSF). The ISFSF, which is permitted by the NRC, consists of a pad on which shielded casks of spent fuel will be stored.

PG&E requested $3.4 million for ISFSF capital expenditures in 2007 and $8.9 million in expense.[125] The Settlement Agreement adopts PG&E's requested capital expenditures for the ISFSF.[126] Expenses for the ISFSF are subsumed in the Settlement outcome for Generation O&M expenses.[127] The Settlement Agreement adopts $450.6 million for Generation O&M expenses in 2007, which is $6.4 million less than PG&E requested.[128]

ANR/SC argues that ratepayer funding for the ISFSF is premature for several reasons. First in June 2006, the Ninth Circuit Court of Appeals ruled that the NRC should supplement the environmental impact statement prepared in connection with the NRC's authorization of the ISFSF to consider the environmental impacts of terrorist attacks.[129] ANR/SC contends that ratepayer funding for the ISFSF project should not be allowed at this time because the project may need to be redesigned and reconstructed.

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[125] Exhibit PG&E-3, Chapter 4, Tables 4-1a and 4-11 on pp. 4-55 and 4-65, respectively.

[126] Settlement Agreement, Appendix G, Table 3-7, Line 32.

[127] Settlement Motion, p. 88.

[128] Settlement Agreement, para. 17.

[129] San Luis Obispo Mothers for Peace v. NRC, 449 F.3d 1016 (9th Cir. 2006).

Second, the NRC held that PG&E may proceed with construction of the ISFSF at its own financial risk.[130] Because PG&E is at risk, ANR/SC believes there is no need for ratepayers to fund the ISFSF until there is resolution of the NRC proceeding pursuant to the Ninth Circuit order.

Third, there has been legislation pending in Congress since February 2005 that calls for spent nuclear fuel to be transferred to the federal government.[131] ANR/SC contends that it would be irresponsible to force ratepayers to fund costs for a storage facility at Diablo Canyon that might not be used.

Finally, ANR/SC believes that onsite storage of high-level nuclear waste poses a substantial threat to public health and safety. ANR/SC urges the Commission to require hardened onsite storage (berms and/or bunkers) and dispersal of the casks over the site to protect against radioactive fallout in the event of a terrorist attack or other acts of malice.

PG&E responds that the Ninth Circuit did not revoke PG&E's license from the NRC to construct and operate the ISFSF. Further, an NRC order issued on September 6, 2006, denied a request filed by the Mothers for Peace to stop PG&E's construction and operation of the ISFSF.[132]

PG&E submits that it is in the public interest to move forward with the ISFSF. The existing spent-fuel pools will be full in 2010. If the ISFSF is not built and ready to store spent fuel, the NRC will not allow Diablo Canyon to continue operations, and PG&E's customers will lose this base-load generating resource and bear the cost of replacement power.

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[130] NRC Memorandum and Order CLI-06-23, September 6, 2005.

[131] H.R. 4538 and S.2099.

[132] NRC Memorandum and Order, Docket No. 72-26-ISFSI (September 6, 2006).

PG&E agrees with ANR/SC that PG&E does bear the financial risk for proceeding with the ISFSF. PG&E defines that risk as recovery of only abandoned-plant cost (and no AFUDC) in the event the ISFSF is not completed.

(2) Discussion

It is likely that Diablo Canyon will continue to operate after 2010. We believe that it is prudent to move forward with construction of the ISFSF for the reasons cited by PG&E. Therefore, we decline to adopt ANR/SC's request to modify the Settlement Agreement to deny funding for the ISFSF.

We appreciate ANR/SC's efforts to safeguard the nuclear waste accumulating at Diablo Canyon from terrorist attack. We encourage ANR/SC and PG&E to work cooperatively to explore cost-effective options for protecting the nuclear waste at Diablo Canyon from attack, such as covering the dry-storage casks with high mounds of dirt.

(C) Reactor Vessel Head Replacement Project

(1) Position of the Parties

PG&E requested a total of $141 million of capital expenditures over the 2007 GRC cycle to replace the Diablo Canyon reactor vessel heads (RVHs). DRA proposed that PG&E file a separate application for the RVHs. PG&E responded that the RVHs need to be replaced, and that DRA and others could review the completed project in the next GRC. The Settlement adopts PG&E's request.[133]

ANR is concerned about ever rising costs for Diablo Canyon. When Diablo Canyon was built, PG&E forecast that the RVHs would last the life of the plant. PG&E now says it needs to replace the RVHs half way through the

133 Settlement Agreement, para. 27, and Appendix G, Table 3-7, Line 24.

current license period. ANR/SC also observes that the forecast cost for RVHs has risen from $67 million in the recent steam generator replacement proceeding to $141 million today. ANR/SC adds that PG&E has not shown a need for new RVHs and, therefore, there should not receive funding for new RVHs.

(2) Discussion

The Settlement allows PG&E to replace its RVHs while allowing DRA and others to review the completed RVH project in the next GRC.[134] We find this outcome to be reasonable in light of the record and in the public interest.

ANR/SC asserts that it is not necessary to replace the RVHs without citing any supporting evidence. In contrast, PG&E presented written and oral testimony explaining why it is necessary to proceed with this project during this GRC cycle. PG&E testified:

> By the end of the current operating cycle on Unit 1, both reactor vessel heads at [Diablo Canyon] will be in the 'high susceptibility' category (as defined by the Nuclear Regulatory Commission) for the onset of cracking in the Reactor Vessel Head penetration nozzles. Nearly all of the domestic pressurized water reactors in this category have already replaced or have ongoing projects to replace their reactor vessel heads. (Exhibit PG&E-18, p. 11-9, L: 18-23.)

Furthermore, PG&E testified that it will be more costly if the RVHs are not replaced because the current RVHs will likely require significant additional maintenance.[135] Specifically, when questioned why PG&E has proposed to replace the RVHs in 2008 and 2009, PG&E's witness responded:

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[134] Settlement Motion, p. 100.

[135] 29 RT 2734:8-25, PG&E/Becker.

> [B]ased on extensive industry experience, the Diablo Canyon reactor vessel heads are about to enter a time period where repairs are becoming likely during refueling outages. And the costs of refueling outages escalate greatly once the repairs start to occur…. So the time to pursue such a project is now, not after those repairs start to occur. The cost to the ratepayer if we waited for the repairs to start to occur would be considerably more costly. (29 RT 2734:13-25, PG&E/Becker.)

For the preceding reasons, we decline to adopt ANR/SC's recommendation. However, we share ANR/SC's concerns about the ever rising costs of maintaining and operating Diablo Canyon. As noted in the Settlement Motion, DRA and other parties can review the cost of the RVH replacement project in the PG&E's next GRC. We encourage ANR/SC to do so.

ii. Conclusion re: Nuclear Capital Expenditures

We find the Settlement Agreement provisions regarding Nuclear capital expenditures are reasonable in light of the record. PG&E provided extensive and generally persuasive testimony supporting its requested Nuclear capital expenditures, which is adopted by the Settlement. Aglet, ANR/SC, and TURN raised several objections to the Nuclear capital expenditures adopted by the Settlement Agreement, all of which we find unconvincing for the previously stated reasons.

We also find the Settlement provisions regarding Nuclear capital expenditures are consistent with applicable law, as there is no credible evidence that any part of the Settlement outcome for Nuclear capital expenditures is contrary to any law, regulation, court order, or Commission decision.

Finally, we find that the level of Nuclear capital expenditures set forth in the Settlement Agreement is in the public interest, as this level will enable PG&E

to continue to operate its 2,200 MW Diablo Canyon Power Plant to provide a large amount of reliable, base load electric power to its customers.

c. Fossil Capital Expenditures

i. Position of the Parties

PG&E requested $3.4 million for Fossil Generation capital expenditures in 2007, $1.7 million in 2008, and $8.3 million in 2009. All of the requested capital expenditures are meant to keep the existing generating units at HBPP operating until new units come online in mid-2009. However, the timeframe for the new units is somewhat uncertain, as PG&E has not yet obtained construction permits or developed a construction schedule.

DRA recommended a disallowance of all capital expenditures for HBPP based on PG&E's plans to replace the existing power plant in mid-2009.

The Settling Parties agree to provide rate recovery for some specified capital projects for the continued operation of the existing generation units at HBPP. These projects are listed in Appendix C of the Settlement Agreement. The estimated revenue requirement for these projects is $1.3 million in 2007, $0.9 million in 2008, and $0.7 million in 2009. The Settling Parties also agree that PG&E will establish a memorandum account to track the difference between the authorized and actual revenue requirement associated with these projects, and, in the next GRC, will refund any unused revenue requirements.[136]

TURN supports memorandum account treatment for HBPP capital expenditures but opposes the provision in the Settlement Agreement allowing PG&E to collect these funds as part of base rates. TURN believes these capital

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[136] Settlement Agreement, para. 30.

projects are unlikely to occur absent major setbacks in the construction of replacement generating units on the site. To the extent that these projects prove necessary, TURN states that PG&E should record the capital costs in the memorandum account and seek recovery in the next GRC.

The Settling parties urge the Commission to reject TURN's proposed modification of the Settlement. They opine that the Settlement Agreement's memorandum account treatment of capital expenditures adequately addresses TURN's concerns about whether these funds will ever be spent.

ii. Discussion

We decline to adopt TURN's proposed modification of the Settlement Agreement. HBPP provides essential load support to the surrounding region. There is no dispute that the requested capital expenditures for the existing facilities at the HBPP will be necessary in the event there is a delay in re-powering HBPP. We believe that it is prudent to plan for these capital expenditures because, until the proposed re-powering project is reviewed by the responsible agencies and the necessary permits for construction and operation of the new units are received, there is uncertainty regarding when the existing units at HBPP will be retired.[137] The HBPP memorandum account provides sufficient protections to ratepayers in the event the relatively modest capital expenditures adopted by the Settlement prove unnecessary.

For the preceding reasons, we conclude that the Settlement outcome for Fossil Generation capital expenditures is reasonable in light of the record, consistent with the law, and in the public interest.

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137 Exhibit PG&E-18, p. 12-4.

d. Generation Plant

PG&E forecasted $11.177 billion of weighted-average plant in 2007 for Generation UCCs. DRA forecasted $10.928 billion, for a difference of $249.3 million. The Settlement adopts $10.954 billion, which is $223.3 million less than PG&E requested and $26.1 million more than DRA recommended. The reduced amount adopted by the Settlement compared to PG&E's request is due almost entirely to nuclear fuel, which is addressed below.

We find the Settlement outcome on this matter is reasonable in light of the record, consistent with applicable law, and in the public interest.

e. Nuclear Fuel Inventory

PG&E sought to include nuclear fuel in rate base. PG&E forecasted a weighted-average nuclear fuel inventory of $221.9 million in 2007.

DRA opposed PG&E's request to include nuclear fuel in rate base. DRA contended that doing so would cost ratepayers more, since ratepayers would bear the carrying costs for fuel inventory at the weighted cost of capital rather than the three-month commercial paper rate. DRA recommended that PG&E recover its nuclear fuel inventory carry costs in its Energy Resource Recovery Account (ERRA) proceeding consistent with long-standing Commission policy.

The Settling Parties agree to exclude nuclear fuel from PG&E's rate base.[138] The carrying costs for nuclear fuel inventory will continue to be collected through the ERRA at the short-term interest rate. No party objected to the Settlement outcome on this matter.

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[138] Settlement, para. 43.

We find the uncontested Settlement outcome for nuclear fuel inventory is reasonable in light of the record, consistent with Commission precedent that excludes nuclear fuel inventory from rate base,[139] and in the public interest.

E. Common and Miscellaneous Revenues, Expenses, and Capital

1. Other Operating Revenues

Other Operating Revenues (OORs) are revenues that are not directly derived from the provision of public utility services. OORs are estimated separately and reduce the utility's revenue requirement.

PG&E initially forecast that OORs in 2007 would be $113.9 million. PG&E subsequently agreed to several minor increases proposed by TURN. With these concessions, PG&E's revised forecast was $114.8 million.

The Settling Parties agree that OORs will be $116.2 million in 2007.[140] The Settlement Agreement reflects the Settling Parties' agreement to increase the fees for bounced checks and reconnection fees.[141]

TURN was the only party to contest PG&E's forecast of OORs. As discussed below, TURN recommends that the Commission modify the Settlement to increase OORs for several items. The Settling Parties respond that the Settlement Agreement increases OORs by $1.4 million above PG&E's litigation position to reflect TURN's positions on OORs. They contend that TURN's recommendation to modify the Settlement to increase OORs would constitute double counting.

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[139] See, for example, D.06-05-016, *mimeo*., pp. 271-275.

[140] Settlement, para. 44.

[141] PG&E's litigation position for OORs also reflected increased fees.

Below, we assess the reasonableness of the Settlement outcome for OORs in light of the record on the issues raised by TURN.

a. Issues Raised by TURN

i. Reconnection Fees

(A) Position of the Parties

PG&E forecasted $2.9 million of revenue from reconnections charges in 2007 based on 2004 recorded data. TURN projects $3.2 million based on 2005 recorded data. TURN testified that there is a clear upward trend in revenues for the five-year period ending in 2005. In light of this upward trend, TURN contends that the 2005 recorded data provides a better basis to forecast 2007 revenues than the 2004 data used by PG&E.

PG&E disagrees with the validity of TURN's trending process. TURN used only the five most recent years even though 10 years of data was available. PG&E states that looking at the data over a longer period shows that recorded reconnection fees have increased four times and decreased four times over the period 1996-2005. This shows, according to PG&E, that reconnection fees fluctuate from year to year and do not follow a trend as suggested by TURN.

(B) Discussion

The record shows that for the 10-year period of 1996-2005, there was a clear down trend in reconnection fees during 1996-2000 and a clear up trend since then.[142] In light of the clear uptrend, we conclude that TURN's forecast of 2007 reconnection fees using 2005 recorded data is superior to PG&E's forecast using 2004 recorded data.

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[142] 12 RT 809:23 – 810:2, PG&E/Hartman.

The difference between PG&E's and TURN's positions is $0.3 million. The Settling Parties assert that adopting TURN's position would constitute double counting because the Settlement Agreement adopts forecasted OORs that exceeds PG&E's litigation position by $1.4 million. We agree with the Settling Parties on this point. TURN was the only party to contest PG&E's forecast of OORs. Consequently, it is reasonable to assume that the amount of OORs adopted by the Settlement Agreement in excess of PG&E's litigation position can only be attributed to TURN.

ii. Timber Sales

(A) Position of the Parties

PG&E forecasted that revenues from timber sales in 2007 would be $2.0 million. TURN forecasted $2.8 million. TURN's forecast is equal to the four-year average of actual timber revenues in 2004 and 2005, and PG&E's forecast of timber revenues in 2006 and 2007. TURN contends that using a four-year average is reasonable because it smoothes out year-to-year fluctuations.

PG&E responds that its forecast is based on expected circumstances in 2007 and, therefore, is better than TURN's retrospective approach.

(B) Discussion

PG&E testified that its forecast of timber sales in 2007 is based on current timber stand conditions and environmental requirements. Using this information, PG&E forecasts that a much higher proportion of the timber harvested in 2007 will be red and white fir. PG&E represents that these trees are low-value, which will depress timber revenues in 2007.[143]

[143] Exhibit PG&E-18, p. 9-3.

TURN does not challenge the veracity of PG&E's testimony. Rather, TURN contends a four-year average provides a better forecast for the 2007 test year and the GRC cycle as a whole.

We find that PG&E and TURN have both presented reasonable forecasts, but that PG&E's forecast will likely be more accurate, at least in 2007, because it is based on current conditions and requirements rather than historical circumstances. We conclude, therefore, that the Settlement outcome on this matter is reasonable in light of the record.

iii. Work Requested by Others

(A) Position of the Parties

PG&E forecasted that it would incur $21.0 million of expenses in 2007 for work requested by others (WRO) and receive $8.5 million of OORs for WRO. TURN recommends that the forecasted OORs for WRO be increased by $1.7 million. TURN observes that PG&E forecasts a significant decrease in the proportion of WRO expenses recovered through WRO revenues. Specifically, total WRO revenues in 2004 comprised 47.7% of total WRO expenses, whereas PG&E's 2007 forecast has revenues at only 35% of total expenses. The result is a 50% increase in costs to ratepayers ($10.2 million in 2004 to $15.7 million in 2007).

TURN believes the main reason why WRO revenues decrease relative to expenses is that PG&E projects that non-generation WRO expenses will increase faster than associated revenues. Non-generation WRO revenues were 51.2% of total non-generation WRO expenses in 2004. PG&E projects that non-generation WRO revenues will fall to 42.2% of non-generation WRO expenses in 2007.

TURN recommends that the Commission increase forecasted WRO revenues by $1.7 million to restore the proportionality between WRO revenues and costs. Under TURN's adjustment, non-generation WRO revenues will remain at 51.2% of non-generation WRO expenses.

PG&E opposes TURN's proposal. PG&E states that it is important to recognize there are two categories of WRO expenses: (1) those expenses that are reimbursable, which should match related revenues (Reimbursable WRO); and (2) those expenses that are not reimbursable (Non-Reimbursable WRO). The forecast of Reimbursable WRO has no impact on PG&E's revenue requirement, since the forecasted expenses are exactly offset by matching forecasted revenues. Only the forecast of Non-Reimbursable WRO affects revenue requirement. Consequently, PG&E's forecasted increase in net WRO expenses relates solely to Non-Reimbursable WRO.

PG&E incurs Non-Reimbursable WRO expense in three areas: relocations, generation interconnects, and pre-parallel inspections. With respect to relocations, PG&E agreed to DRA's proposal to reduce PG&E's projected expenses for 2007 from $11.5 million to $10.2 million. The $10.2 million figure for 2007 is the equal to PG&E's recorded relocation costs in 2004, without inflation. PG&E states that TURN has incorrectly used PG&E's original $11.5 million figure rather than adjusted amount of $10.2 million.

With respect to generation interconnects, PG&E agreed to DRA's proposal to reduce its projected expenses from $3.5 million to $1.6 million. PG&E states that TURN has incorrectly used PG&E's original $3.5 million figure rather than the adjusted amount of $1.6 million.

With respect to pre-parallel inspections, PG&E did not agree to any reduction of its projected expenses of $0.7 million in 2007, even though DRA recommended zero funding. PG&E objected to DRA's proposal because the work does exist and PG&E is obligated to perform these inspections upon a customer's request. Furthermore, in the last GRC these cost were categorized as transmission expenses that are not recovered in GRC proceedings. In 2005, PG&E began recording this work under distribution assets. PG&E's recorded expenses for 2004 (recorded in transmission) were $662,000. PG&E's 2007 forecast of $711,000 represents a modest increase from 2004 of less than 3% per year. PG&E submits that its forecast is reasonable and should be adopted.

(B) Discussion

TURN's principal concern is the decline in the ratio of WRO revenues to WRO expenses from 2004 to 2007. Seeing this decline, TURN concludes that something must be awry, and proposes that the Commission increase forecasted WRO revenues by $1.7 million in 2007 to restore the ratio to its 2004 level.

TURN's proposal is flawed in two respects. First, it rests on a mistaken assumption that PG&E requests $15.7 million of expense for Non-Reimbursable WRO in 2007 compared to $10.2 million in 2004. As noted by PG&E, the $15.7 million figure that TURN uses in 2007 does not reflect PG&E's concessions. When PG&E's concessions are reflected ($1.3 million for relocations and $1.9 million for generation interconnects), the amount requested by PG&E in 2007 for Non-Reimbursable WRO drops to $12.5 million, not the $15.7 million figure cited by TURN.[144]

The remaining differences of $2.3 million between the 2004 recorded expenses for Non-Reimbursable WRO cited by TURN ($10.2 million) and the amount being requested by PG&E in 2007 ($12.5 million) is entirely attributable to generation-related items, i.e., generation interconnects ($1.6 million) and pre-

[144] $12.5 million is the sum of: $10.2 million (Exhibit PG&E-18, p. 17-2, L: 25) plus $1.6 million (PG&E-18, p. 17-3, L: 18) plus $0.7 million (PG&E-18, p. 17-3, L: 22.)

parallel inspections ($0.7 million). TURN does not dispute the reasonableness of PG&E's forecasted expenses of $2.3 million for these items. Rather, TURN's concern is focused on what it saw as an excessive increase in non-generation expenses.[145] In fact, as described above, if the two generation related items – generation interconnects and pre-parallel inspections – are disregarded, there is no increase in the Non-Reimbursable WRO expense for non-generation items.

The second flaw in TURN's proposal to increase WRO revenues in 2007 by $1.7 million is that it is based entirely on the premise that there is fixed ratio of WRO revenues to WRO expenses. Underlying this premise is the implicit assumption that Reimbursable WRO revenues and expenses move in tandem with Non-Reimbursable WRO expenses. However, Reimbursable WRO is different than Non-Reimbursable WRO. TURN did not demonstrate a correlation between these two expense items; nor did it provide a rationale for why these items must move in tandem. Because Reimbursable WRO and Non-Reimbursable WRO are for different services and are triggered by different needs, they cannot be expected to remain in a constant ratio over time.

For the preceding reasons, we find the Settlement outcome for WRO revenues to be reasonable in light of the record. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to increase the forecasted OOR in 2007 by $1.7 million. In any event, this issue is largely moot. For the reasons described previously, the Settlement Agreement appears to adopt at least some of TURN's position on WRO (and other OOR issues).

[145] TURN Comments, pp. 75-76.

2. Administrative and General Expenses

Administrative and General (A&G) expenses are common costs that benefit all of PG&E's lines of business. PG&E conducted an A&G Study (Study) to determine the amount of A&G expense that should be included in its GRC revenue requirement. The Study examined 42 PG&E (Utility) departments and 26 PG&E Corporation (Holding Company) departments. The Study identified each department's total labor, materials, and contract costs. The Study then used an elaborate, multi-step process to allocate these costs among all the UCCs, including those relevant to this GRC.

The Settlement Agreement adopts total Company A&G expenses of $772.3 million in 2007. This outcome is $34 million less than PG&E's request of $806.3 million and $70.1 million more than DRA's recommendation of $702.2 million. The Settlement also allocates the total Company A&G expenses among the UCCs. The amount of A&G expenses allocated to GRC-related UCCs is $709.4 million in 2007, which is $32.8 million less than PG&E requested and $66.5 million more than DRA recommended.[146] The Settling Parties agree that the allocation A&G expenses among the UCCs adopted by the Settlement should be used to determine the A&G expenses in other proceedings until the next GRC.

DRA and TURN raised numerous issues regarding PG&E's requested A&G expenses. Below, we assess the reasonableness of the Settlement outcome for A&G expenses in light of the record on these issues. For convenience, we divided these issues into the following categories: (1) general matters and corporate services; (2) Holding Company issues; (3) employee compensation; (4) other A&G expenses; and (5) unbundling.

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[146] Settlement Agreement, Appendix A, Line 16.

a. General Matters and Corporate Services

i. Issues Addressed by DRA

(A) Normalized Adjustments

DRA proposed a disallowance of $1.145 million for "normalized adjustments." The costs in question were for employee recognition awards, employee lunches and dinners, staff parties, and entertainment activities. PG&E responded that the costs in question are a customary part of doing business, and that failure to recover these costs would place PG&E at a competitive disadvantage in terms of employee recruitment and retention. The Settling Parties agree that the resolution of DRA's normalized adjustments is subsumed in the overall Settlement outcome for A&G expenses.

(B) Time Tracking

DRA expressed concern that PG&E does not have a formal time-tracking system to record time and costs in the Public Policy and Governmental Affairs (PP&GA) departments, particularly those with below-the-line activities. DRA believed that the lack of a time-tracking system could result in excessive charges to ratepayers. The Settling Parties agree that PG&E will implement a time-tracking system no later than January 1, 2008.

(C) Corporate Services

PG&E's Corporate Services includes all the Utility departments that provide services to the Company as a whole. DRA performed an in-depth review of Corporate Services. Based on its review, DRA concurred with much of PG&E's requested expenses for Corporate Services in 2007. The areas of agreement included $1.45 million for the Utility President and CEO; $7.504 million for Corporate Accounting functions; $1.477 million for Industrial Relations; $1.0 million for the Compensation department; $1.883 million for the

Professional Staffing and Diversity department; $2.567 million for Corporate Security; $0.681 million for the office of the Vice President (VP) of ISTS; $25.7 million for legal settlements and judgments; and $0.5 million for the office of the PG&E's Senior Vice President (SVP) and Senior Counsel.

DRA also proposed numerous disallowances of Corporate Services expenses. Most of DRA's proposed disallowances are summarized in the following table:

DRA's Proposed Disallowances of Corporate Services Expenses in 2007 ($ Millions)		
	PG&E Request	**DRA Disallowance**
Utility Corporate Secretary	$0.82	$0.82
Utility Law Department	$37.20	$3.60
Health, Safety, and Claims	$72.70	$0.26
Utility SVP and CFO	$0.78	$0.35
Business and Financial Planning	$1.53	$0.26
Utility VP and Controller	$3.93	$1.75
Management Reporting	$5.17	$1.57
Capital Accounting	$2.28	$0.44
Accounts Payable	$2.67	$0.38
Utility Risk Management	$5.54	$1.50
Public Policy and Gov. Affairs	$30.50	$8.50
SVP Human Resources	$0.80	$0.29
HR Operations, Services & Systems	$5.56	0.63
Supply Chain Purch. Operations	$5.09	$1.04
Total	**$174.57**	**$21.39**

DRA's proposed disallowances in the above table exclude DRA's "normalized adjustments" summarized previously. The bulk of DRA's proposed disallowances shown in the above table were based on its finding that PG&E's requested expenses were excessive when compared to historical expenses and staffing for Corporate Services.

PG&E responded that DRA's analysis of historical data overlooked a substantial amount of data that demonstrated PG&E's requested expenses were reasonable. PG&E also asserted that its expenses would be higher in 2007 compared to historical trends because of costly new requirements (e.g., Sarbanes-Oxley) and programs (e.g., reinstatement of PG&E's commercial paper program).

(D) Discussion

The resolution of the issues raised by DRA regarding A&G expenses is subsumed within the overall Settlement outcome for A&G expenses. The Settlement Agreement provides PG&E with $709.4 million for A&G expenses in 2007, which is $32.8 million less than PG&E requested.[147] We presume the Settlement Agreement, by providing PG&E with less money than it requested, reflects DRA's litigation position to some degree.

We commend DRA for the considerable effort it invested in reviewing and analyzing A&G expenses. Absent the Settlement Agreement, we would have adopted at least some of DRA's proposed disallowances for A&G expenses. TURN contested certain aspects of the Settlement outcome, which we address below. Putting aside the matters disputed by TURN, we find the Settlement outcome for general A&G matters and Corporate Services is reasonable in light of the record, consistent with applicable law, and in the public interest.

[147] Settlement Motion, p. 108.

ii. Issues Raised by TURN

(A) Capitalization of A&G Costs

(1) Position of the Parties

PG&E proposed seven separate capitalization rates for different categories of A&G expenses, including 32.61% for pensions, benefits, and workers' compensation. PG&E also proposed a capitalization rate of zero percent (0.00%) for some A&G expenses, including certain human resource (HR) functions. DRA agreed with PG&E's proposed capitalization rates, which the Settlement adopts.

TURN recommends that the Commission modify the Settlement to adopt a single capitalization rate of 33.09% for all A&G costs, which is equal to the average rate in 2005 and 2006 for pension, benefits, and workers' compensation costs (32.05% and 34.13%). Adopting TURN's proposal would reduce A&G expenses in 2007 by $9.8 million compared to PG&E's request.

TURN claims that PG&E provided contradictory testimony regarding its proposed capitalization rate of 32.61% for pensions, benefits, and workers' compensation. On the one hand, PG&E stated in rebuttal testimony that its proposed rate of 32.61% for 2007 is based on 2004 data. On the other hand, PG&E's witness testified during cross-examination that PG&E's capitalization rate of 32.05% in 2005 was based on 2004 data. TURN argues that the fact that PG&E used the same 2004 data to calculate different capitalization rates for 2005 and 2007 casts doubt on PG&E's proposed capitalization rate of 32.61% in 2007.

TURN opposes PG&E's capitalization rates for other HR functions that range from 0% to 32%. For example, PG&E requests a capitalization rate of zero percent (0.00%) for the Benefits department based on the claim that this department would not avoid any costs in the absence of a capital program. TURN argues that PG&E's rationale makes no sense. The Benefits department provides services to employees assigned to construction projects and, therefore, a portion of the department's costs should be capitalized.

PG&E opposes TURN's uniform capitalization rate of 33.09%. PG&E states that its multiple capitalization rates are based on a department-specific study that was conducted in conformance with the incremental standard prescribed by the Commission and the USOA. Under this approach, each A&G department identified to what extent the department's costs would be avoided in the absence of ongoing construction activities. The avoided costs were then used to determine appropriate capitalization rates. PG&E asserts that TURN has not shown any legitimate flaws in PG&E's approach.

(2) Discussion

TURN recommends a uniform capitalization rate of 33.09% for all A&G departments. To support its recommendation, TURN criticizes PG&E's capitalization rate of zero percent (0.00%) for some A&G departments, and cites PG&E's Benefits department as an example of a department that should capitalize some of its costs. TURN overlooks the fact that the Benefits department provides services to 17,000 retirees.[148] The absence of a capital program would not affect the services provided to retirees. Thus, the work of the Benefits department is driven more by the number of beneficiaries than by the number of employees assigned to construction projects. We concluded that PG&E's proposed capitalization rate of 0.00% for the Benefits department is more reasonable than TURN's proposed rate of 33.09%.

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[148] Exhibit PG&E-6, p. 18-A24.

The record shows that PG&E determined its capitalization rates on a department-by-department basis using an incremental approach. Using this approach, each department determined what costs would be avoided in the absence of an ongoing construction program. The avoided costs were then used to calculate a capitalization rate.[149] In contrast to PG&E's approach, TURN proposes a single capitalization rate for all A&G departments. The calculations used by TURN to develop its proposed rate did not reflect the disaggregation of department costs into cost pools (capital, below-the-line, PG&E Corporation, and affiliates) or the effects of A&G expenses already capitalized through FERC Account 922. PG&E did take these items into consideration when calculating its capitalization rates. Thus, PG&E's approach for calculating capitalization rates is more precise than TURN's.

We conclude for the preceding reasons that there is more support in the record for PG&E's multiple capitalization rates than for TURN's single rate, and that the Settlement's adoption of PG&E's capitalization rates is reasonable in light of the record.

(B) Law Department Costs for Outside Counsel

(1) Position of the Parties

PG&E's requested $19.6 million for outside legal counsel expenses in 2007. PG&E's request was based on recorded expenses for 2005. DRA and TURN both recommended $16.2 million based on 2004 recorded expenses. The Settlement states that the resolution of this matter is subsumed within the overall Settlement outcome for A&G expenses.

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[149] Exhibit PG&E-18, p. 34-22.

TURN argues that PG&E's use of 2005 data instead of 2004 data is rank opportunism. With this one exception, PG&E opposed the use of 2005 data to forecast expenses in 2007. The only reason that TURN can discern for PG&E's use of 2005 data here, but nowhere else, is that the 2005 expenses for outside counsel costs are higher than 2004 and thus more to PG&E's liking.

TURN maintains that the 2005 data used by PG&E is flawed because it includes costs for Department of Energy (DOE) litigation on nuclear waste. When asked to describe the status of the litigation, PG&E claimed the associated costs are being tracked in a balancing account and will be netted against litigation proceeds. TURN argues that PG&E is attempting to double recover DOE litigation costs - once through the balancing account and again in this GRC.

PG&E responds that because the Settlement provides $34.0 million less than PG&E requested for A&G expenses in 2007, it is logical to assume that the Settlement provides PG&E with less than it requested for outside legal costs. PG&E states that TURN has not shown this outcome is unreasonable. PG&E also states that TURN's point about DOE litigation expenses is off the mark because PG&E did not request recovery of any DOE-related litigation costs in this GRC.

(2) Discussion

We conclude that the Settlement outcome for outside legal expenses is reasonable in light of the record. Although we would have preferred if the Settling Parties had used only 2004 base-year data to forecast outside legal costs in 2005, the fact that 2005 recorded data appears to have been used, at least in part, does not render the Settlement outcome unreasonable. TURN alleges that the 2005 data include costs for DOE litigation that PG&E is recovering elsewhere.

PG&E denies the allegation.[150] TURN did not substantiate its allegation with accounting records or other dispositive facts.

On a related matter, we note that in October 2006, PG&E was awarded $42.8 million in damages from the federal government because of the DOE's failure to build a repository for radioactive waste from nuclear power plants. PG&E began remitting waste-storage payments to the federal government in 1985. The total amount paid through December 2004 was $299 million. The Settlement Agreement does not address this matter.

We presume the $42.8 million damage award will be flowed through to PG&E's ratepayers in accordance with the procedures applicable to PG&E's DOE Litigation Balancing Account. Under these procedures, PG&E is required to file an application regarding the disposition of the damage award and to flow through the award, net of associated costs, in its next GRC.

(C) Public Policy and Government Affairs

(1) Position of the Parties

PG&E requested $30.5 million for the PP&GA department in 2007, an increase of 35% over 2004 expenses. TURN recommends that funding for the PP&GA department in 2007 be limited the department's recorded costs in 2004, plus 4.5%. TURN's proposal is $7.7 million less than PG&E's requested funding.

TURN's main concern is that it believes much of the department's expenses are for below-the-line activities, such as lobbying government officials. Although the Settlement requires PG&E to implement an improved system for tracking the time spent by employees on below-the-line activities, TURN

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[150] Exhibit TURN 47, Answer 3A, last sentence; Settling Parties' Reply Comments filed October 5, 2006, p. 65.

contends the tracking system will do little to prevent ratepayer funding of below-the-line activities. TURN argues that the best way to protect ratepayers is to implement TURN's proposed disallowance of $7.7 million.

TURN offers several reasons why its proposed disallowance is reasonable. First, PG&E's requested funding for the PP&GA department in 2007 is 35% higher than the department's costs in 2004. TURN states that the 35% increase is seven times inflation and customer growth, which is unreasonable on its face.

Second, TURN contends that PG&E's requested funding includes an unwarranted increase for regulatory costs. For example, PG&E's request includes $1.126 million for contracts by the Operations Revenue Requirements organization, even though PG&E spent less than half this amount in 2005.

Third, TURN believes it is unfair for ratepayers to provide a substantial increase in funding for the PP&GA department because doing so will strengthen PG&E's ability to obtain rate increases through the regulatory process.

Fourth, PG&E's request includes a 20% increase for the Area Public Affairs (APA) organization, which is responsible for opposing municipalization proposals. TURN asserts that the requested increase for the APA organization is not justified because PG&E has understated the portion of the organization's work that is devoted to below-the-line activities.

Fifth, PG&E justifies its request for significantly higher funding based, in part, on the need for more staff to oversee an increase in contracts related to political spending in recent years while also maintaining that the amount of staff time devoted to political work is expected to decrease due to the absence of major election campaigns. TURN submits that the internal contradictions of PG&E's position undermine its request for significantly higher spending.

Finally, PG&E's request includes an increase of 182% for internal communications expenses. TURN believes that such a large increase is patently unreasonable. TURN asserts that the requested increase is due to poor management that resulted in a meltdown of the internal communications organization, resulting in the departure of key staff and the use of expensive contractors. TURN believes these facts show that PG&E needs cost discipline.

PG&E responds that TURN's proposal to limit funding growth for the PP&GA department in 2007 to a 4.5% increase over 2004 is arbitrary and ignores the projected workload and costs for the department in 2007.

(2) Discussion

The Settling Parties agree that PG&E's total 2007 A&G expenses should be $709.4 million. This outcome is $32.8 million less than PG&E's request of $742.2 million.[151] The Settlement outcome reflects the Settling Parties' resolution of all issues raised by TURN, including TURN's proposed disallowance of $7.7 million for PP&GA department costs.

We presume that the Settlement outcome reflects some, but not all, of TURN's proposed disallowance of PP&GA department costs. To determine if this is a reasonable outcome, it is necessary to assess whether the record supports the adoption of TURN's entire disallowance. If the answer is in the affirmative, then this would be one indication that the Settlement is not reasonable in light of the whole record. Conversely, if we find that some or all of TURN's disallowance should not be adopted, then this would lend weight to the conclusion that that Settlement is reasonable in light of the whole record.

[151] Settlement Agreement, Appendix A, Line 16.

TURN recommended an increase of 4.5% PP&GA department expenses in 2007 compared to 2004, which represents the approximate customer growth from 2004 to 2007.[152] TURN's proposal ignores inflation and other cost drivers, and assumes that expenses for the PP&GA department are strictly correlated with customer growth. TURN provided no evidence to support this assumption. In contrast, PG&E provided testimony showing that the drivers of cost growth for the PP&GA department are increases in work load that are not materially related to customer growth.[153] Based on PG&E's testimony, we conclude that an increase of greater than 4.5% is warranted for the PP&GA department.

TURN offers several reasons why it's proposed disallowance of $7.7 million is reasonable. We find that TURN has demonstrated that some disallowance of PP&GA costs is justified, and this is reflected in the Settlement Agreement for the previously stated reasons. However, we also find that PG&E has justified the bulk of its requested funding for the PP&GA department.

For the preceding reasons, we conclude that the Settlement Agreement outcome with respect to PG&E's PP&GA department is reasonable in light of the whole record, consistent with the law, and in the public interest.

(D) Membership Dues and Political Contributions

(1) Position of the Parties

PG&E requested recovery of membership dues for organizations that engage in political activities. TURN asked the Commission to disallow these costs. The Settlement Motion stipulates that the resolution of TURN's

152 Exhibit TURN-1, p. 57.

153 Exhibit PG&E-6, Chapter 14; and Exhibit PG&E-18, Chapter 47.

recommended disallowance is subsumed within the Settlement's overall outcome for A&G expenses, O&M expenses, and rate base.

TURN observes that long-standing Commission precedent requires that political donations be funded by shareholders, not ratepayers. TURN argues that the Settlement Agreement fails to adhere to this precedent by not explicitly adopting the disallowances proposed by TURN for the following dues and contributions paid to organization that engage in political activities :

Organization	Disallowance
Local Chambers of Commerce	$26,000
California Business Roundtable (CBR)	$25,000
Calif. Commission for Jobs & Economic Growth (CCJEG)	$50,000
BIPAC	$6,000
Civil Justice Assoc. of Calif.	$29,657
Total	**$136,657**

The Settling Parties oppose any modification of the Settlement Agreement. They state that TURN's recommended disallowances are already reflected in the Settlement outcome for A&G expenses, O&M expenses, and rate base.

PG&E addresses each of TURN's proposed disallowances. PG&E agrees with TURN that membership dues for local Chambers of Commerce should be borne by shareholders. However, PG&E disagrees with TURN's proposed disallowance of $26,000. PG&E represents that it never requested $11,000 of this amount, and that the remaining $15,000 is part of the overall Settlement.

PG&E opposes TURN's request to disallow $25,000 paid to the CBR and $50,000 paid to the CCJEG. Again, the resolution of these disallowances is part of the overall Settlement. Moreover, PG&E claims that these organizations do more than lobbying and provide customer benefits. As such, PG&E believes it is proper to charge ratepayers for the membership dues for these organizations.

PG&E represents that TURN's proposed disallowance of $6,000 for PG&E's contributions to BIPAC is moot because PG&E withdrew is request for BIPAC funding in its rebuttal testimony.

Finally, PG&E opposes TURN's disallowance of $29,657 contributed to the Civil Justice Association of California. PG&E contends that reasonable parties may differ on whether this amount should be the responsibility of ratepayers or shareholders. PG&E opines that the test is not whether the Settlement adopts or rejects any particular position, but whether the Settlement generally balances the various interests at stake and is consistent with policy objectives and the law.

(2) Discussion

Long-standing Commission policy prohibits rate recovery of any costs for political lobbying or advocacy. This policy is reflected in numerous Commission decisions[154] and underlies the purpose of the below-the-line Account 426.4.[155] We find that TURN's proposed disallowances fall into this category.

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154 See, for example, D.96-01-011, 1996 Cal. PUC LEXIS 26, *14, and D.89-12-057, 1989 Cal. PUC LEXIS 687, *36.

155 FERC Account 426.4 defines lobbying activities that should not be funded by ratepayers as follows: "This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."

The Settlement Agreement would be inconsistent with the law and contrary to the public interest if it allowed into rates any of the costs that TURN seeks to disallow. PG&E has provided persuasive testimony that it has not sought, and the Settlement does not provide, rate recovery for some of TURN's proposed disallowances (i.e., $11,000 for Chamber of Commerce membership dues and $6,000 for BIPAC membership dues).[156]

The Settlement's treatment of the remainder of TURN's proposed disallowance totaling $120,657 is somewhat ambiguous. The Settling Parties do not state that TURN's proposed disallowances are adopted, only that the resolution of the issues raised by TURN are subsumed within the overall Settlement outcome. Fortunately, the amount at issue borders on being *de minimis*, and we may safely assume that all of TURN's remaining disallowance of $120,657 is reflected in the Settlement Agreement.

We will adopt the Settlement Agreement with the understanding that it does not provide any funding for political activities. Henceforth, PG&E shall identify and track all expenditures for membership dues in organizations that engage in political activities, including all the organizations identified by TURN in this proceeding, and record an appropriate proportion of these expenditures in the below-the-line Account 426.4.

b. Holding Company Costs

i. Issued Raised by DRA

PG&E's parent company, PG&E Corporation (the Holding Company), provides support services to PG&E. PG&E requested $65.96 million for these

[156] Exhibit PG&E-18, pp. 34-15 and 34-16; and Exhibit PG&E-18, pp. 46-28 to 46-29.

services in 2007, which represents 94% of the Holding Company's above-the-line costs. DRA recommended $32.42 million, for a difference of $33.54 million.

DRA's recommendation was based on an extensive review of Holding Company costs allocated to PG&E. DRA analyzed each category costs allocated to PG&E to determine the extent the Holding Company and PG&E each benefited from these costs. DRA then divided each category of costs between the Holding Company and the Utility based on their relative share of the benefits. Based on its analysis, DRA concluded that 49% of the Holding Company's costs should be allocated to PG&E.

PG&E responded that its request excluded all incremental costs for activities at the Holding Company that either (1) provide no demonstrable benefit to PG&E, or (2) if performed by PG&E, could be performed more efficiently or at a lower overall cost.

The Settling Parties agree that the resolution of the issues raised by DRA regarding Holding Company costs is subsumed within the Settlement outcome for A&G expenses. The Settlement provides PG&E with $709.4 million for A&G expenses in 2007, which is $32.8 million less than PG&E requested.[157]

We commend DRA for its thorough analysis of Holding Company costs allocated to PG&E. Absent the Settlement Agreement, we would have adopted some, but not all, of DRA's proposed disallowance of these costs.

We assume the Settlement outcome reflects DRA's litigation position on Holding Company costs by providing PG&E with less money for A&G expenses than it requested. With this assumption in mind, we find the Settlement outcome

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[157] Settlement Motion, p. 108.

for the Holding Company issues raised by DRA is reasonable in light of the record, consistent with applicable law, and in the public interest.

ii. Issues Raised by TURN

TURN challenges PG&E's requested revenue requirement for the Holding Company's SVP of the PP&GA department. PG&E requested $0.619 million for this department in 2007.[158]

TURN argues that this department's costs should be frozen at the 2004 level of $0.420 million. PG&E responds that TURN's proposal is based on its mistaken belief that the department's costs increased from 2004 ($0.420 million) to 2007 ($0.530 million). However, PG&E's errata corrected the 2004 recorded amount for this department from $0.420 million to $0.702 million.[159] Therefore, PG&E's 2007 test-year request ($0.619 million) is less than this department's costs in 2004 ($0.720 million). PG&E believes this issue is now moot.

We find that the record shows that PG&E's requested expenses for the PP&GA department in 2007 are less than the department's actual costs in 2004. Therefore, we agree with PG&E that this issue is moot.

c. Employee Compensation

i. Total Compensation

DRA and PG&E jointly selected Towers Perrin to conduct the Total Compensation Study (Compensation Study). The purpose of the Compensation Study was to compare the total compensation paid to PG&E's employees (i.e., base pay, bonuses, and employee benefits) to the labor market represented by a

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158 PG&E allocated 47% of this department's total costs below-the-line because they relate to political contributions.

159 Exhibit PG&E-16, p. 16-205; Exhibit PG&E-18, p. 46-24 to p. 46-26.

survey of selected industrial and utility companies. The Compensation Study revealed that PG&E's total compensation is 4.71% above the survey average. Towers Perrin considers +/- 10% of the market average to be the range of competitiveness. Since PG&E's total compensation falls within this range, the Compensation Study indicates that PG&E's total compensation is reasonable.

No party disputed the reasonableness of PG&E's total compensation. However, DRA contested one element of PG&E's compensation. The parities' litigation positions on this issues are summarized below.

(A) Employee Incentive Plan

PG&E employees are eligible for annual bonuses under the Performance Incentive Plan (PIP). The Total Compensation Study included the actual PIP payments made in 2004. PG&E requested $56.2 million for PIP payments in 2007, equivalent to 50% of the maximum potential payout and below the historical average. Shareholders would bear the cost of PIP payments over 50%.

PG&E Corporation's Short-term Incentive Plan (STIP) is similar to PG&E's PIP. PG&E requested $5.1 million in 2007 for STIP expenses, equivalent to 50% of the maximum potential payout.

DRA recommended that the Commission disallow half of PG&E's request for PIP, or $28.1 million. DRA contended that PG&E's PIP payout percentage has increased significantly since 2000, and that ratepayers should not have to pay for the increase. DRA also argued that shareholders benefit from PIP costs and, therefore, should share the forecasted costs.

DRA argued that because STIP costs are incurred at the Holding Company level, these costs should first be disallowed in the same proportion as DRA's proposed disallowance of other Holding Company costs, and then reduced another 50% consistent with DRA's PIP recommendations.

PG&E responded that the requested PIP expenses are reasonable because total compensation, of which PIP is a component, is reasonable. Further, when a utility provides safe and reliable service and earns its authorized rate of return, as reflected in the PIP award, both customers and shareholders benefit and the Commission cannot realistically allocate between these two groups the reasonable PIP costs to achieve these twin goals. PG&E also contended that its request is supported by the Commission's decision in SCE's recent GRC. There, the Commission granted full recovery of incentive pay based on actual costs.[160] Here, PG&E has requested recovery of target costs (50% of maximum potential payout), which is lower than PG&E's historical percentage payout.

PG&E opposed DRA's proposed disallowance of STIP costs for the same reasons it opposed DRA's recommendation for PIP.

The Settling Parties agree that issues regarding total compensation, PIP, and STIP are subsumed in the Settlement outcome for A&G expenses. The Settlement provides PG&E with $709.4 million in A&G expenses in 2007, which is $32.8 million less than PG&E requested.[161] No party contested this aspect of the Settlement Agreement.

(B) Discussion

We find that the uncontested Settlement outcome for total compensation, PIP, and STIP is reasonable in light of the record, consistent with applicable law, and in the public interest.

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[160] D.06-05-016, *mimeo*., p. 129.

[161] Settlement Motion, p. 108.

ii. Pensions and Benefits

PG&E's employee compensation includes the following benefits: (1) pension benefits, (2) various medical benefits, (3) post-retirement benefits other than pensions (PBOPs), (4) group life insurance, (5) flexible benefit program, (6) long-term disability (LTD), (7) retirement savings plan, (8) tuition refund, (9) relocation expenses, and (10) service awards.

PG&E requested $768.98 million for benefits expenses in 2007 for the entire Company, before capitalized and other allocated amounts are removed. DRA, Aglet, and TURN raised several issues regarding PG&E's requested benefits expenses. Below, we assess the reasonableness of the Settlement outcome on benefits expenses in light of the record on the major categories of benefits expenses and the issues raised by the parties.

(A) Pension Contributions

In D.06-06-014, which was issued earlier in this proceeding, the Commission adopted an uncontested settlement agreement that authorizes PG&E to (1) contribute $249.7 million to its Pension trust in 2006 and $153.4 million annually in 2007-2009, and (2) recover the following revenue requirement for its GRC lines of business during 2006-2009:

$ Millions				
GRC Line of Business	**2006**	**2007**	**2008**	**2009**
Electric Distribution	77.2	46.8	48.4	50.5
Gas Distribution	34.5	26.2	27.2	28.3
Electric Generation	43.3	25.3	26.2	27.3
GRC Total	155.0	98.2	101.7	106.1
Source: D.06-06-014, *mimeo.*, p. 2.				

PG&E is authorized by D.06-06-014 to recover the revenue requirement shown in the above table for the pension contributions in 2007-2009 in the base rates authorized by today's Opinion.[162] The contributions authorized by D.06-06-014 are projected to result in a fully funded pension plan by January 1, 2010.[163]

D.06-06-014 resolved all issues concerning PG&E's pension costs for the years 2007-2009. However, because the Settlement extends the GRC cycle through the year 2010, the Settling Parties agree that pension-contribution settlement approved by D.06-06-014 for the years 2007-2009 should be extended through 2010. The relevant provisions are in paragraphs 37-39 of the Settlement Agreement and include the following:

1. PG&E will make a total pension contribution of $176.0 million for the year 2010, which equates to a net contribution of $153.4 million. (D.06-06-014, FOF 10 and OP 5.)
2. PG&E will recover in base rates the revenue requirement for the portion of the pension contribution authorized for 2010 that is allocable to PG&E's GRC lines of business. Recovery of the pension-contribution revenue requirement for non-GRC lines of business will be authorized, as appropriate, in other proceedings and venues. (D.06-06-014, OP 6.)
3. The advice letter required by OP 7 of D.06-06-014 will extend through the year 2010.
4. The annual report required by OP 8 of D.06-06-014 will continue through the year 2011.

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[162] The revenue requirement is less than the contributions because a portion of the contributions is capitalized and recovered over time through depreciation expense.

[163] D.06-06-014, *mimeo.,* pp. 9 -10.

The revenue requirement for pension costs adopted in D.06-06-014 and the Settlement Agreement is in addition to the GRC revenue requirement adopted by the Settlement. The cumulative increase in GRC revenues (other than pension costs) adopted by the Settlement is $1.637 billion through 2010.[164] The cumulative increase in revenues for pension costs is $417 million through 2010.[165]

There is no opposition to the Settlement outcome for pensions costs. We find the Settlement outcome on this matter is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

(B) Issues Raised by DRA

(1) Medical Escalation Rates

PG&E requested $217.8 million for medical benefit expenses in 2007. DRA recommended $195.6 million. PG&E forecasted medical benefit costs in 2007 by escalating 2004 recorded costs by medical-trend factors less savings from plan changes. PG&E based its trend factors on (1) claims and enrollment information, (2) national trend data, and (3) Global Insight's forecast of the Employment Cost Index for Health Insurance (ECIHI).[166]

DRA forecasted medical benefit costs in 2007 by escalating 2004 recorded costs by Global Insight's projection of the ECIHI. Aglet agreed with DRA.

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164 $1.637 billion = $852 million for 2007 (i.e., $213 million x 4) + $375 million for 2008 (i.e., $125 million x 3) + $250 million for 2009 (i.e., $125 million x 2) + $125 million for 2010, + $35 million for the Diablo Canyon refueling outage in 2009 or 2010.

165 $417 million = $98 million (2007) + $102 million (2008) + $106 million (2009) + $111 million (2010). The amounts for 2007-2009 are from D.06-06-014, *mimeo.*, p. 2. The amount for 2010 is estimated.

166 Global Insight is a private company that provides econometric forecasts that are used regularly in Commission proceedings.

PG&E responded that the ECIHI does not accurately track PG&E's medical benefits costs. PG&E also asserted that Global Insight's previous forecasts of the ECIHI have been (1) lower than PG&E's medical trend experience, and (2) lower than the actual ECIHI, as reported by the Bureau of Labor Statistics.

(2) Service Award Program

PG&E's Service Award Program provides each employee with a "thank you" gift at every five-year anniversary and at retirement. PG&E requested $1.1 million for this program in 2007.

DRA argued that several Commission decisions have denied ratepayer funding for awards that fit into the category of social activities, and that PG&E's Service Award Program should be disallowed on the same basis.

PG&E responded that its Service Awards are not social activities, but tangible tokens of appreciation for continuous employee service. Moreover, the Service Awards Program is part of PG&E's total compensation package -- a package that is within the range of market compensation.

(3) Relocation Benefits

PG&E provides relocation benefits to assist employees with costs associated with Company-initiated moves. PG&E requested $2.61 million for relocation expenses for PG&E employees in 2007 and $0.7 million for Holding Company employees. DRA concurred with PG&E's request for its own employees, but recommended that PG&E's request for Holding Company employees be reduced by 50%. PG&E opposed DRA's proposed reduction.

(4) PBOP Medical and Disability Benefits

PG&E requested $58.2 million in 2007 for contributions to a Voluntary Employee Benefits Association (VEBA) trust to fund PG&E's retirement medical plan. PG&E's request was based on the lower of (1) PBOPs expense determined in accordance with Statement of Financial Accounting Standard (SFAS) No. 106, or (2) tax-deductible limits on VEBA contributions.

PG&E also requested $66.1 million in 2007 for tax-deductible contributions to its LTD VEBA trust to fund (1) pay-as-you-go costs for current disabled employees, (2) the increase in the actuarial accrued liability, and (3) amortization of the unfunded accrued liability.

DRA concurred. No other party addressed this matter.

(5) The Settlement Agreement

The Settling Parties agree that the resolution of issues regarding medical escalation rates, Service Awards, allocation of Holding Company benefits costs to PG&E, and funding of PBOP and disability contributions is subsumed in the Settlement outcome for all A&G expenses. The Settlement Agreement provides PG&E with $709.4 million for A&G expenses in 2007, which is $32.8 million less than PG&E requested and $66.5 million more than DRA recommended.

The Settlement Agreement also requires PG&E to contribute 124.3 million annually to its PBOP VEBA trusts during 2007 - 2010. As required by D.92-12-015 and D.95-12-055, the Settlement provides that PG&E will file at the end of the 2007 GRC cycle a consolidated true-up of the actual contributions to the PBOP VEBA trusts with the revenue requirement collected in rates.[167]

The was no opposition to the Settlement outcome for benefits costs.

(6) Discussion

We find the uncontested Settlement outcome for benefits costs is reasonable in light of the record, consistent with applicable law, and in the public

[167] Settlement Motion, p. 184, and Settlement Agreement, para. 32.

interest. Our finding includes one caveat. Specifically, to ensure there is no misunderstanding of PG&E's obligation under the Settlement Agreement to contribute $124.3 million annually to its PBOP trusts, we remind PG&E that Ordering Paragraph 2 of D.92-12-015 requires any funds collected in rates for contributions to PBOP trusts to be used for that purpose or returned to ratepayers.[168] The report that PG&E is required to submit pursuant to the Settlement Agreement in 2010 regarding its PBOP contributions[169] shall state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.

(C) Aglet's Comparison of Utility Medical Costs

(1) Position of the Parties

Aglet is concerned that PG&E's employee medical expenses appear to be high compared to SCE's. The following table compares PG&E's and SCE's medical costs per employee in nominal dollars:

Year	PG&E	Increase	SCE	Increase
2004	$7,553	--	$5,317	14.0%
2005	$8,666	14.7%	$5,849	10.0%
2006	$9,060	4.5%	$5,849	0.0%
2007	$9,957	9.9%	--	--

The above comparison leads Aglet to recommend that the Commission order PG&E to provide in its next GRC proceeding a report that (1) compares

168 D.92-12-015, 46 CPUC 2d 499, 532. See also D.95-12-055, 63 CPUC 2d 570, 593-94, and D.00-02-046, 4 CPUC 3d 315, 463.

169 Settlement Agreement, para. 32.

PG&E's unit medical benefit costs with similar costs for SCE, SDG&E, and SCG; (2) analyzes differences between PG&E's costs and similar costs for the same utilities; and (3) describes the status of negotiations with both represented and non-represented employees regarding future medical benefits.

PG&E opposes Aglet's recommendation. PG&E responds that the above table is misleading because it is limited to active employees and ignores retirees. PG&E's average medical cost for both active and retired employees was approximately $7,000 per participant in 2006, which was lower than SCE's average of more than $8,000.

PG&E also argues that Aglet's proposed report is unnecessary because PG&E already submits in GRC proceedings a Total Compensation Study that compares the total compensation paid to PG&E's employees (including medical benefits) to the total compensation paid by similar employers. PG&E states that the Total Compensation Study uses a fair methodology to compare employee benefits that minimizes the effects of employer differences in demographics, regional pricing differences, and plan utilization, which facilitates accurate comparison of benefit plans across employers.

(2) Discussion

Aglet has demonstrated that PG&E's medical benefit costs for active employees are significantly higher than SCE's. Still, PG&E's overall compensation, including medical benefit costs, is within the range of competitiveness, as discussed above. We agree with Aglet that it would be useful for PG&E to explain the reasons for its higher medical costs in the next GRC. But we will not require the specific reporting requirements recommended by Aglet.

(D) TURN's Linkage of P&B Costs to Payroll

(1) Position of the Parties

PG&E's forecast of pension and benefit (P&B) expenses in 2007 was based on 2004 recorded expenses updated to reflect cost trends and expected plan changes. The Settlement Agreement adopts PG&E's methodology.

TURN observes that PG&E did not forecast its P&B costs based on the number of employees it would have in 2007. Consequently, if employee numbers (and labor costs) change as a result of recommendations made by TURN or others, there will be no corresponding change to PG&E's P&B costs.

TURN believes it is unreasonable to assume that P&B costs will remain unchanged if there is a disallowance of employee labor costs. According to TURN, any disallowance of labor costs should translate into fewer employees and lower P&B costs. Therefore, if there is a disallowance of labor costs, TURN recommends that there also be a proportional disallowance of P&B costs.

PG&E responded that it would manage any disallowance of labor costs by reducing overtime and/or hiring-hall labor which have no associated P&B costs.

(2) Discussion

We decline to adopt TURN's recommendation to reduce PG&E's P&B costs in proportion to any disallowance of labor expenses. PG&E testified that if it needs to lower labor expenses, it intends to do so by reducing overtime and hiring-hall labor. PG&E further testified that (1) PG&E employees working overtime do not receive additional pensions and benefits, and (2) hiring-hall workers are not PG&E employees and do not participate in PG&E's P&B plans. Therefore, any reduction of overtime and hiring-hall labor would not affect

PG&E's P&B costs.[170] Thus, it is inappropriate to reduce P&B costs in proportion to disallowed labor expenses as TURN proposes.

We recognize that overtime and hiring-hall labor represent only a small portion of PG&E's labor costs. If the Commission were to disallow a significant amount of labor costs, it is likely that PG&E would have to reduce its workforce. It would probably make sense in that situation to reduce the P&B costs associated with the reduction in PG&E's workforce. However, because today's Opinion does not adopt a major reduction to labor costs, it is unnecessary to consider partial implementation of TURN's recommendation.

d. Other A&G Expenses

PG&E's request for Other A&G expenses in 2007 had four components. First, PG&E requested $82.5 million for Account 925 expenses. These expenses include workers' compensation, settlements and judgments, and certain insurance costs. No party objected to the request.

Second, PG&E requested $1.2 million for severance benefits. DRA argued that PG&E had not justified the need for this program. PG&E responded that the program benefits ratepayers by facilitating organizational restructurings that enhance operational effectiveness, and that the Commission has previously authorized funding for severance benefits.

Third, PG&E requested $27.4 million for property insurance, directors and officers liability insurance, and general liability insurance. No party objected.

Finally, PG&E requested $82 million for Miscellaneous A&G Costs, which included $78.9 million for so-called "non-study departments" (NSDs). The NSDs

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170 Exhibit PG&E-18, p. 1-5, L: 20-26.

include ISTS and Corporate Real Estate (CRE). DRA proposed disallowances totaling $68.7 million for ISTS and CRE, which are addressed, *infra*.

The Settling Parties agree that the resolution of issues concerning Other A&G expenses is subsumed in the Settlement outcome for all A&G expenses. The Settlement provides $709.4 million for GRC-related A&G expenses in 2007, which is $32.7 million less than PG&E requested $66.5 million more than DRA recommended.[171] There is no opposition to the Settlement on this matter.

We find the uncontested Settlement outcome for Other A&G expenses, including the outcome for ISTS and CRE expenses that is addressed, *infra*, is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

e. Unbundling

The term "unbundling" refers to the process of separating PG&E's costs into major lines-of-business called Unbundled Cost Categories (UCCs). By separating costs into UCCs, the Commission can better match the cost-of-service with the customers who receive those services. The unbundling process includes the allocation of common costs such as A&G expenses, which are not directly assignable to a particular UCC.

DRA agreed with PG&E's list of UCCs and methodology for unbundling common costs, which is reflected in the Settlement Agreement. There is no opposition to this aspect of the Settlement.

We find the uncontested Settlement outcome on unbundling to be reasonable in light of the record and consistent with Commission precedent.

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171 Settlement Agreement, Appendix A, Line 16.

f. Conclusion re: A&G Expenses

For the preceding reasons, we conclude that the Settlement Agreement provisions regarding A&G expenses are reasonable in light of the record, consistent with the law, and in the public interest, and should be adopted.

3. General Services and Other Support Costs

PG&E's General Services organizations provide services to PG&E as a whole. These services include transportation, materials handling, building services, and the Company airplane. Most expenses incurred by the General Services organizations are direct-charged to the organizations that use the services and are included in PG&E's requests for the user departments.

a. Areas of Agreement

There was no opposition to PG&E's requested expenses and capital expenditures in the following categories of General Services:

Areas of Agreement re: 2007 General Services Expenses and Capital Expenditures		
Area	**Requested Expenses (millions)**	**Requested Cap. Ex. (millions)**
Utility Support Operations	$7.0	$1.3
Materials Operations	- -	$34.1
Purchasing Operations	$0.1	$1.3
Total	$7.1	$36.70

The Settling Parties agree that (1) expenses for the above categories of General Services are subsumed within the Settlement outcomes for A&G and O&M expenses, and (2) capital expenditures for the above categories of General Services are subsumed within the overall Settlement outcomes capital additions and rate base.[172] There was no opposition to the Settlement outcomes for the above categories of General Services.

Based on our review of the record, we find the uncontested Settlement outcome for Utility Operations Support, Materials Operations, and Purchasing Operations is reasonable in light of the record, consistent with the law, and in the public interest.

b. Issues Raised by the Parties

DRA, Aglet, and TURN opposed several facets of PG&E's requested expenses and capital expenditures for General Services. Below, we assess the reasonableness of the Settlement outcome for General Services in light of the record on the issues raised by the parties.

i. Transportation Services Capital Expenditures

PG&E operates a transportation fleet of approximately 11,937 cars, trucks, power-operated equipment, off-road equipment, and trailers. PG&E has 64 service facilities to maintain and repair its fleet.

PG&E requested $150.2 million for capital expenditures in 2007 to replace worn-out fleet equipment, comply with environmental mandates, and to manage, repair, and maintain fleet assets.[173] PG&E also requested $0.961 million for tools. DRA recommended $72.9 million for fleet replacement and $0.519 million for tools. TURN also had one recommendation.

The litigation positions of the parties are summarized below.

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172 Settlement Motion, p. 188.

173 The 2007 amount requested by PG&E reflects a reduction in capital expenditures of $15.8 million during 2006-2009 that was proposed by TURN and accepted by PG&E.

(A) Equipment Replacement

DRA proposed two reductions to PG&E's requested capital expenditures in 2007 to purchase transportation vehicles and equipment. First, DRA recommended a reduction of $24 million to replace long-term rentals with PG&E-owned equipment. Both parties agreed on the need to replace long-term rentals, but DRA proposed that this be accomplished over three years, whereas PG&E proposed that all rentals be replaced in 2007.

Second, DRA proposed a reduction of $52.3 million based on historical capital expenditures. PG&E responded that historical spending had resulted in an aging fleet that is increasingly costly to maintain. Continued spending at historical levels would result in an even older fleet.

PG&E presented evidence that showed existing assets are getting older, and almost 30% are failing before being replaced. PG&E contended that it was unreasonable to expect employees to operate equipment past its life cycle or to expect customers to accept delays in service because of unreliable equipment.

(B) EPA Compliance

DRA disagreed with two elements of PG&E's request for capital expenditures to comply with the federal Environmental Protection Act (EPA). First, DRA proposed a disallowance of $6.5 million based on its concern that $6.5 million was being double counted. PG&E demonstrated in Exhibit PG&E-43 that the double counting error was $1.275 million, not $6.5 million. PG&E and DRA subsequently agreed to an adjustment of $1.275 million.

Second, DRA proposed a disallowance of $2.045 million for the purchase of green-fuel vehicles over 8,500 lb. gross vehicle weight. DRA's proposal was based on its reading of a PG&E data response, which DRA interpreted as indicating that PG&E might not purchase the vehicles. PG&E responded that

DRA's interpretation was incorrect; PG&E's data response had nothing to do with whether PG&E would purchase the vehicles, but whether the vehicles that PG&E purchased would qualify for a tax credit.

(C) Capital Tools

DRA proposed that PG&E's requested capital expenditures for tools in 2007 be reduced from $0.961 million to $0.519 million. DRA based its proposal on a four-year average of historical spending. PG&E responded that historical spending should not be used as the basis for future expenditures because of changed circumstances.

For example, in 2004 the Corporate Real Estate (CRE) department was responsible for fuel islands, fuel dispensers, wash racks, garage doors, and recycling systems. Responsibility for these items was transferred to Transportation Services in 2005. As a result, PG&E's requested capital expenditures for tools for CRE decreased significantly, but increased significantly for Transportation Services. PG&E argued that it was unfair to accept the CRE decrease without a corresponding increase for Transportation Services.

PG&E also contended that DRA's proposal should be adjusted to include $0.115 million to replace PG&E's TRAC fuel system, which was installed in the 1980's and was not captured in the 4-year historical average used by DRA.

(D) Issues Raised By TURN

TURN recommended that PG&E's rate base be reduced by $37.5 million due to improper accounting for rental savings. TURN argued that fleet rental costs were outside the Results of Operations (RO) model, and that ratepayers would pay the capital costs to replace rentals but would not receive the savings from reduced rental payments. PG&E agreed that customers should benefit from reduced rental costs, and PG&E represents that it incorporated the projected savings into the Comparison Exhibit.

(E) The Settlement Agreement

The Settling Parties agree that the resolution of issues concerning Transportation Services capital expenditures is subsumed within the Settlement outcomes for capital additions and rate base.[174] There is no opposition to this aspect of the Settlement Agreement.

(F) Discussion

PG&E's Transportation Services organization is essential to PG&E's ability to provide utility services to the public. No party contests the Settlement provisions pertaining to Transpiration Services, and no party alleges that these provisions violate any law or regulation. To the contrary, the record shows that Settlement provides funding for PG&E's transportation fleet and operations to comply with applicable environmental laws and regulations.

For the preceding reasons, we conclude that the Settlement outcome for Transpirations Services is reasonable in light of the record, consistent with the law, and in the public interest.

ii. Company Airplane

(A) Position of the Parties

(1) The Settlement Agreement

PG&E requested $18 million to replace its Company airplane, a Fairchild-Dornier 328 turbo-prop that PG&E purchased new in 1994. The existing airplane carries 350 to 400 employees monthly, primarily between Oakland and San Luis

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[174] Settlement Motion, p. 188.

Obispo. The plane flew 559 hours in 2004 and 492 hours in 2005. PG&E expects increased usage of the Company plane due to major capital projects that are currently underway at the Diablo Canyon and Humboldt Bay power plants.

PG&E testified that the Company airplane increases employee productivity by limiting the hours spent traveling to and from job sites. Owning an airplane also provides PG&E with complete control over critical safety and reliability issues, such as pilot quality and training, aircraft maintenance, passenger and baggage manifests, and operational safety standards.

PG&E is concerned about the safety and reliability of the current airplane because of reduced access to spare parts and required refresher training courses for flight crews. According to PG&E, the availability of replacement parts has declined in the four years since the manufacturer declared bankruptcy. When PG&E can obtain a replacement part, it is usually a repaired unit. A repaired unit is not completely overhauled; only the broken component within the part is repaired. PG&E testified that it has received replacement parts with much higher total times on them than the part needing replacement.

PG&E performed a net present value (NPV) analysis of the alternatives for direct access to an airplane, including purchase, lease, charters, commercial airlines, and maintenance of the existing plane. Based on its analysis, PG&E concluded that the purchase of a used Embraer Legacy Shuttle is the best option. PG&E obtained price quotes in the range of $15-21 million for a used Embraer. PG&E submits that its $18 million request is an appropriate middle point to forecast the cost of the replacement plane.

PG&E testified that the replacement airplane, like the current plane, will be used to shuttle employees to job sites. There will be relatively little use of the plane for executive transport. PG&E also provided data showing that the

Holding Company rarely uses the existing plane. Given that PG&E will continue to be the primary user of the Company airplane, PG&E contends that it is appropriate that the cost of the replacement airplane be borne by PG&E, with appropriate charges to the Holding Company for its use of the airplane, if any.

PG&E charges for use of the Company plane. For PG&E employees and contractors, a $400 charge is levied on the department for whom the PG&E employee or contractor works. If an elected official uses the aircraft, PG&E complies with all regulations governing services and gifts to elected officials. For other passengers, use of the plane must be approved by a Vice President and that officer's department is charged for use of the airplane. PG&E represents that it prohibits personal use of the plane.

DRA opposed PG&E's request for a replacement airplane on the grounds that PG&E had not adequately supported its request. If PG&E were allowed to acquire another airplane, DRA proposed that the cost of the plane be borne by the Holding Company, with appropriate charges to the Utility, because the Holding Company has priority use of the plane.

The Settling Parties agree that PG&E's request to acquire a replacement airplane is included in the $81.9 million weighted-average capital additions for Generation adopted by the Settlement. The Settling Parties further agree that PG&E will review and update the charges for use of the airplane and submit a report to the Commission and DRA within 90 days of today's Opinion.[175]

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175 Settlement Agreement, paras. 28 and 29.

(2) Aglet

Aglet opposes rate recovery for a replacement airplane. Aglet asserts that PG&E has not shown that it needs another plane, has not justified its estimate of the market value of the existing plane, and has not fairly allocated costs to the Holding Company, which has priority for use of the plane.

Aglet also recommends that the Commission remove from test-year expenses the majority of operating costs for a Company airplane. Aglet submits that PG&E has not justified rate recovery of expenses that benefit the Holding Company more than the Utility.

(3) TURN

TURN asserts that PG&E has not demonstrated a need for a replacement aircraft. The purported unavailability of spare parts is undermined by a newspaper article that quotes the general manager of a major aircraft servicing company as stating that the supply of spare parts is robust and that a typical Dornier 328 should have a service life of 30-40 years.

TURN criticizes PG&E's NPV analysis of acquiring a replacement plane. TURN states that PG&E did not analyze any intermediate options, such as retaining the existing plane for this GRC cycle and replacing it with a leased plane in 2010. TURN also believes that PG&E's NPV analysis is flawed because PG&E used a discount rate based on the lower, after-tax cost of capital instead of the higher, pre-tax cost of capital actually paid by ratepayers. Using an after-tax rate skews the NPV calculations in favor of ownership.

If PG&E is allowed to acquire a replacement plane, TURN recommends that PG&E lease rather than buy. TURN states that with PG&E's proposed 8-year depreciable life, owning an airplane would cost nearly $9 million more over the GRC cycle relative to leasing. If a 13-year depreciable life is presumed for a replacement aircraft (which mirrors the life of the current Dornier 328), ownership would cost $6.5 million more than leasing over the 2007-2009 GRC cycle. If the Commission nonetheless allows PG&E to purchase an airplane rather than lease, TURN recommends that the Commission adopt a 13-year depreciation life for the aircraft (based on the life achieved by the current plane) rather than the 8-year life used in PG&E's analysis.

If the Commission approves either a purchase or lease, TURN asks the Commission to reduce rate base by $2 million (by increasing accumulated depreciation) to include PG&E's estimated salvage value for the existing airplane. TURN represents that PG&E concedes that $2 million is a reasonable estimate of the salvage value, and that PG&E confirmed that the Settlement does not incorporate this concession. TURN urges the Commission to include this concession in the final decision.

TURN recommends that PG&E implement three changes to its policies governing the Company airplane. First, PG&E must ensure that charges for use of the airplane are reasonable. PG&E has a chargeback system in place, and PG&E has agreed to review and update this system as part of the Settlement. However, TURN is concerned that this will only lead to an update of the current charge of $400 per person, per flight. Rather than developing a generic cost estimate, TURN believes PG&E should calculate chargebacks based on the incremental cost of using the airplane for a specific trip.

Second, TURN recommends that PG&E implement a cost-containment policy for use of the plane. Currently, PG&E uses the plane when there are lower-cost alternatives. For example, PG&E's CEO used the plane when lower-cost commercial flights were readily available. TURN submits that it is not reasonable for ratepayers to finance the preferred business travel arrangements of PG&E executives when less expensive (and suitable) alternatives exist.

Finally, TURN has uncovered problems with personal use of the Company plane. For example, PG&E's former CEO used the plane for personal travel and brought family members along. There is no evidence that PG&E was reimbursed for such usage. TURN recommends that the Commission require PG&E to establish a written policy on personal usage of the plane and to implement procedures which ensure that PG&E is compensated for any non-business use at the incremental cost of the trip (not a generic chargeback).

(B) Discussion

The Settling Parties agree that PG&E's request for $18 million to purchase a replacement airplane is included in the Settlement's $81.9 million weighted-average capital additions for Generation in 2007. The Settlement Agreement adopts the full amount of PG&E's request for Generation capital additions in 2007.[176] Based on this information, we conclude that the Settlement Agreement adopts PG&E's position on the replacement airplane.

We begin our analysis of the Settlement outcome with an assessment of PG&E's need for an airplane. PG&E testified that its plane is in the air 450 to 500 hours annually, and that the plane transports 350 to 400 employees monthly.[177] PG&E also testified that the plane is used primarily to shuttle employees between Company work sites, and there is very little use of the plane by the Holding Company or to transport executives to non-utility locations. According

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176 Settlement Agreement, Appendix G, Table 3-7, Line 32.

177 Exhibit PG&E-88, p. 55-1.

to PG&E, the plane increases employee productivity by limiting the hours spent traveling hundreds of miles to and from job sites.

Based on PG&E's testimony, we conclude that PG&E has a reasonable need for an airplane. PG&E has also demonstrated that the Utility is the primary beneficiary of the airplane, even though the Holding Company uses the plane occasionally. Based on our conclusion, we deny Aglet's request to prohibit rate recovery of the majority of the expenses for an airplane.

We next consider PG&E's request to replace its existing airplane. TURN presented testimony which shows that keeping the existing aircraft has a slight cost advantage over the next 13 years compared to the acquisition of a replacement aircraft.[178] PG&E testified that its current plane is 13 years old and has become difficult to maintain since the manufacturer declared bankruptcy several years ago. TURN challenged PG&E's testimony with hearsay from an article in the *San Francisco Chronicle*. We accord greater weight to PG&E's sworn testimony that PG&E's existing aircraft will not adequately meet PG&E's needs because of the safety and reliability concerns caused by reduced access to quality parts and required training courses for PG&E's flight crews.[179] Based on the record evidence, we conclude that PG&E has demonstrated a reasonable need for a replacement aircraft. Therefore, we deny TURN's request to prohibit rate recovery of a replacement aircraft in the current GRC cycle.

PG&E and TURN presented conflicting testimony on whether it is cheaper to buy or lease a replacement airplane. PG&E performed an NPV analysis that used an after-tax weighted cost of capital and assumed that the cost of the lease

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178 Exhibit TURN-1, p. 13, Table 1.

179 Exhibit PG&E-18, pp. 55-1 to 55-3.

must be increased by additional equity financing to offset "lease debt."[180] PG&E's analysis shows the NPV of leasing is marginally cheaper than buying.[181] TURN used PG&E's data and a pre-tax cost of capital. TURN's analysis shows that leasing is cheaper than buying over a 13-year period.

We find that PG&E and TURN each presented a flawed analysis. PG&E's analysis is flawed because it used an after-tax cost of capital, which is much lower than the pre-tax cost of capital paid by PG&E's ratepayers. PG&E also used the inappropriate assumption that PG&E must borrow money to pay for a lease, even though the lease payments would recovered in rates. The flaws in PG&E's analysis increased lease costs relative to purchase costs.

TURN's analysis is flawed in the way it set up the comparison for lease versus buy. The lease payments used by TURN assume a residual value of 60% for the leased aircraft.[182] In contrast, TURN's computation of depreciation expense under the purchase scenario assumes an aircraft salvage value of 20%. In order to have an apples-to-apples comparison of lease versus buy, it is necessary to have the same ending value for the aircraft under both the lease scenario and the purchase scenario. By using a 60% residual value for the lease scenario compared to a 20% salvage value under the purchase scenario, TURN understated the cost of leasing compared to buying. In addition, TURN included property taxes in its determination of aircraft purchase costs,[183] but TURN seems to have excluded property taxes from its determination of lease costs. TURN's

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180 33 TR 3132:1-4.

181 Exhibit PG&E-18, p. 55-6; Exhibit DRA-80, p. 17; and 33 TR 3129:24-28.

182 Exhibit TURN-1, Attachment 4, p. 5, and Attachment 5, p. 3.

183 Exhibit TURN-1, Attachment 5, spreadsheets on pp. 4 and 5, Column 12.

treatment of property taxes appears to have inflated aircraft purchase costs relative to lease costs.

The information in the record is insufficient to make a precise comparison of leasing versus buying a replacement aircraft. Based on our review of the record, we conclude that the total costs to ratepayers to lease a replacement aircraft or purchase a replacement aircraft over the next 13 years will be similar, whether measured in present-value dollars or nominal dollars. For the preceding reasons, we find the Settlement Agreement's provisions that allow PG&E to purchase a replacement aircraft in 2007 for $18 million are reasonable in light of the whole record and in the public interest.

We agree with TURN that (1) rate base should be reduced in 2007 by $2 million for the net salvage value of the existing aircraft, and (2) the replacement aircraft should be depreciated over 13 years, which would mirror the life of PG&E's current aircraft. Based on our review of the RO model, it appears that both of TURN's recommendation are reflected in the Settlement Agreement in a round about way.[184]

We decline to adopt TURN proposals to establish new policies and charges for the use of the Company airplane. PG&E testified that it already charges for use of the existing airplane:

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[184] Our review of the Settlement RO model shows that $18 million for the replacement plane is added to Diablo Canyon capital on January 1, 2007, and is depreciated at an annual rate of 3.9%. This rate reflects a service life that is much longer than TURN's proposed depreciation period of 13 years. The long service life assumed by the RO model for the replacement airplane more than offsets any cost increases that might be caused by the inclusion of zero salvage value for the current airplane in the RO model. In the next GRC, PG&E should reduce rate base by the actual salvage value on the existing airplane and present an appropriate depreciation expense for the replacement airplane based on a 13-year service life.

> For PG&E employees and contractor's working directly for PG&E, a $400 charge is made to the PCC or order number of the department for whom the PG&E employee or contractor works. If an elected official uses the aircraft, PG&E complies with all state and federal regulations governing services and gifts to elected officials. For other passengers, use of the airplane must be approved by a Vice President and the PCC or order number for that officer is charged for use of the airplane. (Exhibit PG&E-18, p. 55-6.)

Holding Company employees are treated the same as Utility employees.[185] The Settlement addresses the efficacy of PG&E's charges by requiring PG&E to evaluate its current charges and to report its findings to the Commission.[186]

PG&E also testified that its policies prohibit personal use of the plane. To address TURN's concern about the need for a written policy on personal use of the airplane, the Settlement Agreement provides the following written policy:

> PG&E employees (including employees, officers, and Board members of PG&E Corporation) will be prohibited from using the Company airplane for personal travel for themselves or their family. PG&E customers and contractors, including customers and contractors of PG&E Corporation, will also be prohibited from using the Company plane for personal travel for themselves or their family. (Settlement Agreement, para. 28.)

If there is a violation of the written policy, the individual will pay for the flight.[187]

We conclude that PG&E's existing policies and the Settlement Agreement provisions regarding use of the Company airplane are satisfactory.

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185 33 TR 3134: 3-9.

186 Settlement, para. 29.

187 33 TR 3150: 23-28, 3151:1-2.

iii. Corporate Real Estate

PG&E's Corporate Real Estate (CRE) department is responsible for the planning, design, construction, maintenance, and operation of over 845 building and yards at more than 190 locations. PG&E's facilities include offices, call centers, data centers, meeting and training facilities, service centers, shops, warehouses, construction yards, and garages. These facilities support day-to-day operations as well as service restoration after storms and natural disasters.

The following tables show PG&E's requested CRE expenses and capital expenditures in 2007 and DRA's proposed disallowances:

2007 Corporate Real Estate Expenses		
Item	**Requested Expenses (millions)**	**Proposed Disallowance (millions)**
Building & Yard Maint.	$11.30	$6.07
Redevelop. & New Constr.	$2.00	$1.00
Building Seismic Safety	$3.40	$1.70
Americans w/Disability Act	$4.80	$2.40
Building Permit Initiative	$0.52	$0.26
Green Building Initiative	$8.80	$4.40
Repair & Replace Furniture	$0.11	$0.06
Real Estate Management	$6.90	- -
Total	**$37.83**	**$15.89**

2007 Corporate Real Estate Capital Expenditures		
Item	**Requested Cap. Ex (millions)**	**Proposed Disallowance (millions)**
Tools, Equip., & Furniture	$5.0	- -
Building & Yard Maint.	$19.00	$9.10
Redevelop. & New Constr.	$18.77	$11.20
Building Seismic Safety	$1.88	- -
Building Permit Initiative	$3.03	$1.60
Green Building Initiative	$5.87	$4.70
Lemoore Service Center	$0.50	$0.50
Total	**$54.05**	**$27.10**

The bulk of DRA's proposed disallowances of CRE expenses was based on its conclusion that PG&E's requested expenses for maintenance, repairs, and upgrades were too ambitious in light of historical expending, and that the requested expenses should be spread over a longer period so as to mitigate the annual financial impact on ratepayers. PG&E responded that the timing of the expenses was driven by the age and condition of its buildings, seismic safety concerns, environmental stewardship, and regulatory compliance.

The majority of DRA's proposed disallowances of CRE capital expenditures stemmed from DRA's conclusion that PG&E's request was excessive in light of historical expenditures and activities. PG&E responded that its requested expenditures were driven by customer growth, the condition of its aging facilities, operational needs, and regulatory compliance.

The Settling Parties agree that the resolution of issues regarding CRE expenses (other than depreciation) is subsumed in the Settlement outcomes for

A&G expenses and O&M expenses.[188] The Settlement provides $708.7 million for A&G expenses in 2007, which is $32.8 million less than PG&E requested.[189] With respect to O&M expenses, the Settlement provides $1.079 billion in 2007, which is $15 million less than PG&E requested.[190] There is no opposition to the Settlement outcome on CRE expenses.

The Settlement Agreement adopts PG&E's requested CRE capital expenditures.[191] There is no opposition to the Settlement outcome on this matter.

We conclude that the uncontested Settlement outcome for CRE expenses and capital expenditures is reasonable in light of the record summarized above. In our opinion, PG&E has justified almost all of its requested expenses for CRE, and all of its requested capital expenditures, which is consistent with the Settlement outcome. The Settlement outcome is also consistent with the law in that much of PG&E's requested CRE expenses and capital expenditures are needed to comply with various local, state, and federal requirements. Finally, the Settlement outcome is in the public interest because it provides PG&E with sufficient revenue to maintain and acquire real estate assets that are necessary to the provision of utility services to the public.

iv. Environmental Programs

PG&E's Environmental Programs encompass the Environmental Affairs department and personnel throughout the Utility who are responsible for (1) compliance with environmental laws, and (2) programs implemented solely

188 Settlement Motion, p. 188.

189 Settlement Agreement, para. 31 and Appendix A, Line 16.

190 Settlement Agreement, para. 17.

191 Settlement Motion, p. 210.

for environmental purposes. PG&E requested the following for Environmental Programs in 2007: (i) $2.6 million for A&G expenses; (ii) $14.7 million for O&M expenses; and (iii) $4.9 million for capital expenditures.

There was no opposition to PG&E's requested O&M expenses and capital expenditures. DRA proposed two reductions to A&G expenses. First DRA proposed a "normalized adjustment" of $34,776 to remove costs for employee recognition awards; staff lunches, dinners, and parities; and entertainment activities. PG&E responded that these are legitimate business expenses.

Second, DRA proposed a disallowance of $0.208 million based on PG&E's 2004 recorded expenses instead of PG&E's 2007 forecast. PG&E responded that it will have higher costs in 2007 compared to 2004 because of emerging issues associated with global climate change.

The Settling Parties agree that the resolution of issues regarding Environmental Programs expenses is subsumed in the Settlement outcome for all A&G expenses and O&M expenses.[192] The Settlement provides $708.7 million for A&G expenses in 2007, which is $32.8 million less than PG&E requested.[193] With respect to O&M expenses, the Settlement provides $1.079 billion in 2007, which is $15 million less than PG&E requested.[194] The Settling Parties also agree that capital expenditures for Environmental Programs are subsumed in the broader Settlement outcome for capital additions and rate base.[195] The Settlement adopts PG&E's position on capital additions and rate base for common plant.

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[192] Settlement Motion, p. 188.

[193] Settlement Agreement, para. 31 and Appendix A, Line 16.

[194] Settlement Agreement, para. 17.

[195] Settlement Motion, p. 188.

We find that PG&E has justified the great majority of its requested expenses and capital expenditures for Environmental Programs in 2007. It is reasonable to expect that such expenses and capital expenditures will increase significantly in 2007 compared to 2004 due to major new environmental laws, such as the recently enacted law limiting greenhouse gas emissions in California.

DRA's proposed normalized adjustment is consistent with Commission precedent. We interpret the Settlement outcome, which grants PG&E less than it requested for A&G expenses as a whole, as accommodating a 100% disallowance for DRA's normalized adjustment of $34,776. With this understanding, we find that the Settlement outcome for Environmental Programs is reasonable in light of the record, consistent with applicable law, and in the public interest.

v. Information Technology

PG&E's Information Services and Technology Services (ISTS) organization installs, operates, and maintains many of PG&E's information and telecommunication systems. PG&E requested the following funding for ISTS:

- $72.37 million for A&G expenses in 2007 and $55.8 million for Gas and Electric Distribution O&M expenses in 2007.
- $57.5 million for capital expenditures in 2007.

DRA proposed several reductions to PG&E's requested expenses and capital expenditures for ISTS. No other party addressed ISTS. The disallowances proposed by DRA are shown in the following tables:

Proposed Disallowances of ISTS Expenses in 2007	
Item	**millions**
Customer Information System (CIS)	$4.218
SAP Operations	$0.121
Utility Applications	$4.254
Security Risk Management A&G	$7.360
Security Risk Management O&M	$4.346
Total Proposed Disallowances	**$20.299**

Proposed Disallowances of ISTS Cap. Ex in 2007	
Item	**millions**
Desktop Computers	$6.640
CIS Infrastructure	$1.100
Total Proposed Disallowances	**$7.740**

The bulk of DRA's proposed disallowances for ISTS expense and capital expenditures was based on DRA's conclusion that PG&E's request for 2007 was excessive compared to historical spending. DRA was also concerned about possible double counting of AMI related costs recovered in other proceedings.

PG&E responded that DRA had overlooked or ignored historical data that showed PG&E's requested expenses and capital expenditures were reasonable. PG&E also argued that its request was reasonable in light of inflation, aging computers, and costly new regulatory requirements (e.g., Sarbanes Oxley). Finally, PG&E denied there was any double recovery of any AMI-related costs.

The Settling Parties agree that (1) the resolution of issues concerning ISTS capital expenditures is subsumed within the overall Settlement outcomes for capital additions and rate base,[196] and (2) the resolution of issues concerning A&G and O&M expenses for the ISTS organization is subsumed within the overall Settlement outcome for all A&G and O&M expenses.[197] The is no opposition to the Settlement as it pertains to the ISTS organization.

Based on our review of the record, we conclude that the uncontested Settlement outcome for the ISTS organization is a fair compromise, reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Common Plant Capital Expenditures

PG&E requested $397.938 million for common plant capital expenditures in 2007 (including $18 million for Diablo Canyon capital). DRA recommended $256.896 million, for a difference of $141.042 million. The Settlement Agreement adopts PG&E's position in full.

The Settling Parties agree on the following allocation of the capital expenditures for common plant:

Electric Distribution General Plant	$2.192 million
Gas Distribution General Plant	$1.080 million
Electric Generation General Plant	$52.307 million
Common Plant	$342.359 million
Total	**$397.938** million

Issues regarding specific components of the Settlement outcome for common plant capital expenditures (e.g., the Company airplane) are addressed elsewhere in today's Opinion. Except as noted elsewhere, we find the Settlement

[196] Settlement Agreement, paras. 27, 43.

[197] Settlement Agreement, paras. 17, 31.

outcome for common plant capital expenditures is reasonable in light of the record, complies with all applicable laws, and is in the public interest.

5. Customer Advances for Construction

Customer Advances for Construction (CAC) are refundable advances paid by developers for new utility facilities and are recorded as an offset (reduction) to rate base. PG&E used its December 2004 recorded CAC balance of $125.424 million as its 2007 test-year forecast based on the assumption that CAC will remain stable. The Settlement adopts this amount.[198]

a. Position of the Parties

TURN states there is a seasonal pattern for CAC. The pattern shows higher CAC balances during the summer, so that the annual average is higher than the year-end figure. So, rather than using a December 2004 amount as proposed by PG&E, TURN recommends that the Commission use the average 2005 CAC balance, thereby raising the CAC forecast by $2.96 million.

PG&E responds that it used the December 2004 recorded CAC balance to forecast CAC in 2007 because (1) PG&E believes there will not be a substantial change in CAC over the next several years, and (2) the ending 2004 CAC balance is very close to the weighted-average balance for the four-year period of 2001 - 2004. DRA accepted PG&E's forecast as reasonable.

b. Discussion

TURN's recommendation would increase CAC by $2.96 million for 2007, which is 2.4% above the Settlement amount of $125.424 million. PG&E and TURN agree that the CAC balance is affected by the level of residential

[198] Settlement Comparison Exhibit, Tables 1-10 and 2-10, line 14 in each table.

construction activity.[199] Recent economic data shows there has been a substantial downturn in residential construction in California. In the first eight months of 2006, homebuilding in California was down nearly 16% from the same period in 2005.[200] Based on this data, we conclude that it is reasonable to adopt the Settlement Agreement's slightly lower forecast of CAC in 2007.

6. Transfer of CAC to CIAC

As mentioned earlier, CAC consists of refundable advances paid by developers for new utility facilities. CAC is included in gross plant but excluded from rate base because it represents assets that were not paid with shareholder dollars. However, sometimes CAC is not refunded. When this occurs, it is transferred to contributions in aid of construction (CIAC). Like CAC, the CIAC balance is included in gross plant but excluded from rate base.

PG&E's forecast of CAC was based on 2004 recorded data. PG&E did not forecast CIAC, contending that it was unnecessary to do so because the CAC-to-CIAC transfer has no effect on rate base. The Settlement implicitly adopts PG&E's approach.

a. Position of the Parties

TURN states that PG&E used a budget-based approach to forecast plant-in-service, and there is no line item in the forecast to reduce forecasted plant-in-service (and rate base) for CAC-to-CIAC transfers. TURN maintains that PG&E's forecast of plant-in-service ignores the accumulation of CIAC from

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199 16 TR 1288, L: 12-15, PG&E/Togneri; TURN Comments on the Settlement Agreement, p. 148.

200 California Department of Finance October 2006 monthly economic update. (http://www.dof.ca.gov/HTML/FINBULL/2006_FB/October/Oct06.asp) We take official notice of this economic data pursuant to Rule 13.9.

CAC-to-CIAC transfers. As a result, PG&E's forecasted rate base to be too high. To remedy this error, TURN recommends that the 2007 rate base be reduced by $3.784 million based on a four-year average of CAC-to-CIAC transfers. TURN adds that the Commission adopted the exact same recommendation in the recent SCE GRC proceeding.[201] TURN believes there is no reason to decide this issue differently for PG&E.

PG&E opposes TURN's proposal. PG&E contends there was no need to separately forecast CIAC because the net effect for each CAC-to-CIAC transfer on rate base is zero. PG&E adds that although the Commission adopted an adjustment for CAC-to-CIAC transfers in the recent SCE GRC, the Commission did not address the merits of the issue. Rather, D.06-05-016 rejects SCE's assertion that the issue is immaterial and adopts TURN's proposed amount.[202]

b. Discussion

PG&E's forecast of rate base in 2007 is equal to its 2004 rate base plus budgeted increases during 2005-2007. The 2004 rate base reflects then-existing balances for CAC and CIAC.[203] There is no dispute that PG&E's forecast of rate base in 2007 does not reflect an increased amount of CIAC relative to 2004.

PG&E argues that because CAC-to-CIAC transfers have no effect on rate base, it is unnecessary to forecast CIAC in 2007. We are not persuaded. The CIAC balance is not static, but grows over time with CAC-to-CIAC transfers. This can be seen with a simple hypothetical. In the hypothetical, $10 is recorded in CAC every January 1 and transferred to CIAC every December 31. The

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[201] D.06-05-015, *mimeo.*, pp. 217-218.

[202] D.06-05-016, *mimeo.*, pp. 218-219.

[203] Exhibit TURN-1, pp. 77-78.

average CAC balance is always $10, but the CIAC balance grows by $10 each year, reaching $100 after 10 years.

PG&E's forecast of rate base in 2007 does not reflect the increase in CIAC due to CAC-to-CIAC transfers during 2005-2007. Consequently, PG&E's forecasted rate base is too high. The Settlement adopts PG&E's forecast. It is the Commission's long standing policy that rate base should not include CIAC. The failure of the Settlement Agreement to reduce rate base for the accumulation of CIAC is contrary to decades of Commission precedent.[204]

Although we agree with the merits of TURN's position, we decline to modify the Settlement to reduce rate base in 2007 by $3.784 million as recommended by TURN. The associated reduction to PG&E's revenue requirement in 2007, as calculated by the RO model, is $0.225 million. The impact of TURN's proposed reductions is *de minimis* in relation to the rate base and revenue requirement adopted by the Settlement of $12.550 billion and $4.927 billion, respectively, and does not warrant our modifying, let alone rejecting, the Settlement Agreement.[205]

7. Working Cash

Working cash is part of rate base and consists of two elements: (1) funds needed for the utility's daily operations, which is generally calculated by adding and subtracting certain specified items; and (2) the timing of inflows and

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[204] The following is a partial list of the hundreds of decisions that have excluded CIAC from rate base: D.06-06-036, D.06-05-016, D.05-07-044, D.04-07-034, and D.01-08-039.

[205] In its comments on the Alternate Proposed Decision, PG&E promises that in the next GRC proceeding it will remedy the erroneous method it used to forecast CAC-to-CIAC transfers in the instant GRC proceeding. We expect PG&E to uphold its promise.

outflows of cash that is calculated by a lead-lag study. The computation of working cash is guided by Standard Practice (SP) U-16, dated September 13, 1968. A positive amount of working cash represents a permanent investment in the utility and is included in rate base. Negative working cash represents funds provided by ratepayers and reduces rate base.

a. The Settlement Agreement

PG&E forecasted $140.714 million of working cash in 2007. DRA recommended $72.767 million.[206] The amount sought by PG&E concedes several minor issues raised by DRA and TURN.

PG&E and DRA disagreed on several items of working cash, the most significant being the treatment of franchise fees in the lead-lag study. DRA proposed to increase the weighting of franchise fees in the lead-lag study by including franchise fees recovered in other proceedings and venues.

The Settlement Agreement adopts working cash of $143.742 million.[207] This is $3.030 million more than PG&E requested and $70.974 million more than DRA recommended.[208] Most of DRA's proposed adjustments to working cash are not incorporated in the Settlement's calculation of working cash. Rather, the working cash adopted by the Settlement is a residual amount that is based largely on the effect that other elements of the Settlement have on the calculation of working cash. The Settling Parties agree that the resolution of all working cash issues is subsumed by the broader Settlement outcome for rate base. The

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[206] Settlement Agreement, Appendix G, Tables 1-9, 2-9, and 3-9.

[207] $143,742 million = $53,941 (Electric Distribution) + $56.381 million (Gas Distribution) + $33.420 million (Generation). (Settlement, Appendix G, Tables 1-9, 2-9, and 3-9.)

[208] Settlement Agreement, Appendix G, Tables 1-9, 2-9, and 3-9.

Settling Parties further agree that the Settlement outcome for working cash reflects consideration of Aglet's and TURN's proposals regarding working cash.

Aglet and TURN proposed that PG&E's working cash be reduced by the amount of customer deposits. TURN proposed a reduction of $146.8 million and Aglet suggested a reduction of $164.9 million. Adopting either amount would result in negative working cash. TURN also recommended two adjustments to the lead-lag calculation, resulting in a working cash reduction of $5.286 million. We address Aglet's and TURN's proposed reductions to working cash below.

b. Customer Deposits

PG&E requires new customers to establish credit under Tariff Rule 6. A customer who does not qualify for credit must submit a deposit pursuant to Tariff Rule 7. PG&E refunds the deposits within 12 months to those customers that have generally paid their bills on time. PG&E must also pay interest on the deposits equal to the three-month commercial paper rate.

PG&E did not request interest on customer deposits as an operating expense. In addition, PG&E did not deduct customer deposits from working cash because SP U-16 stipulates that only "interest-free" customer deposits should reduce working cash. The Settlement adopts PG&E's position.

i. Position of the Parties

(A) Aglet

Aglet recommends that the Commission reduce PG&E's working cash (and rate base) by the amount of customer deposits. Aglet acknowledges that SP U-16 indicates that PG&E's interest-bearing customer deposits should be excluded from the calculation of working cash. However, in SCE's test-year 2003 GRC, the Commission found that circumstances had changed since SP U-16 was issued, and that customer deposits now represent a substantial and permanent source of capital provided by ratepayers.[209] In SCE's test-year 2006 GRC, there was no opposition to reducing rate base by customer deposits. The Commission concurred, stating that it was "reasonable to include the entire forecasted weighted average customer deposit balance as an offset to rate base.[210]"

Aglet forecasts customer deposits of $164.891 million in 2007, the same as the 2005 average. Because customer deposits earn interest at the three-month commercial paper rate, Aglet recommends that PG&E's expenses in 2007 be increased to include this interest expense. Aglet submitted documents that showed the 3-month commercial paper rate reported in Federal Reserve Statistical Release, H-15, dated September 11, 2006, was 5.21%.

(B) TURN

TURN argues that the circumstance which led to a departure from SP U-16 for SCE apply equally to PG&E. TURN represents that the Commission's change in policy for SCE relied on two facts. First, SCE's customer deposits have grown significantly since SP U-16 was issued. TURN provided the following graph that shows PG&E's customers deposits have also grown significantly, rising from less than $45 million in 1996 to almost $150 million in December 2005:

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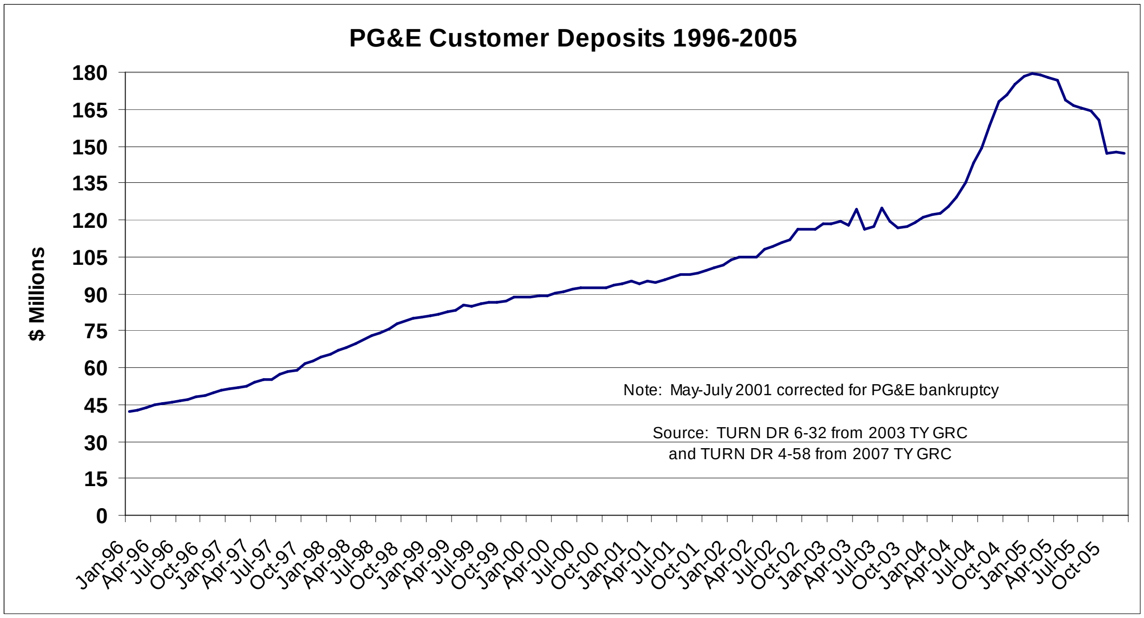
[209] D.04-07-022, *mimeo*., pp. 242-247 and FOF 208-210 at p. 332.

[210] D.06-05-016, *mimeo*., pp. 279-282, FOF 178 at p. 372.



The second reason for the Commission's change in policy for SCE was a widening of the spread between short-term interest rates and utility rates of return. TURN showed that the three-month commercial paper rate paid on customer deposits is currently around 5.5%, while PG&E's rate of return is approximately 13%, resulting in a spread of 7.5%.

TURN acknowledges that PG&E may have used customer deposits in prior years to finance large balancing account undercollections. However, TURN argues that the undercollections were caused by circumstances that will not recur due to the following new laws and regulations:

- Automatic increases in electric rates are required if power-cost balancing accounts are under collected by 5% or more.[211]
- Monthly revisions to gas procurement rates based on monthly gas price forecasts.

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211 See § 454.5(d)(3), which was extended by D.04-12-048, *mimeo.*, p. 113.

TURN believes that the significantly reduced level of PG&E's balancing account undercollections since it exited from bankruptcy in April 2004 demonstrates that the previously identified reforms have permanently reduced the likelihood of large undercollections. In any event, TURN states that the level of balancing account undercollections is irrelevant to whether customer deposits are a permanent source of capital.

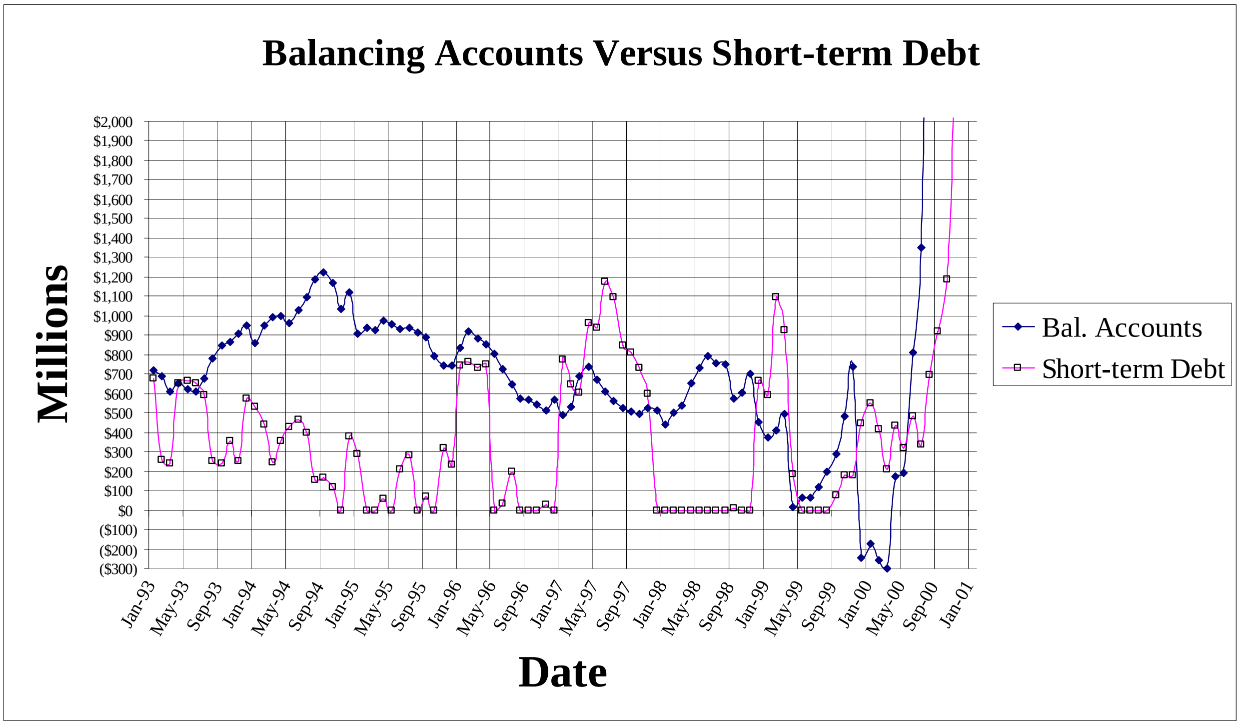
TURN suggests that the most reasonable forecast of customer deposits in 2007 is $146.775 million, the recorded amount at the end of 2005.

(C) PG&E and the Other Settling Parties

PG&E opposes Aglet's and TURN's recommendation to reduce working cash (and rate base) to reflect customer deposits. PG&E contends their recommendation is contrary to SP U-16, which excludes interest-bearing customer deposits from the determination of working cash.

PG&E represents that it has historically used customer deposits to finance large undercollections in various balancing accounts. PG&E maintains that its balancing accounts were under collected 95% of the time during 1993-2004. These undercollections averaged $690 million during 1993-1999, and $3.8 billion during 2000-2004. At the end of 2004, PG&E's balancing accounts were under collected by $159 million. PG&E believes that undercollections are likely to persist, although perhaps not at historical levels.

PG&E provided the following graph to illustrate that balancing account undercollections have significantly exceeded PG&E's short-term debt:



PG&E submits that the above graph shows that undercollections usually exceeded short-term debt outstanding, which proves that undercollections could not have been financed with short-term debt alone. Moreover, much of the short-term debt shown in the above graph was used for purposes other than balancing account undercollections, which demonstrates PG&E's need to use customer deposits to finance undercollections. PG&E argues that it would be unfair for the Commission to force PG&E to pay 13% on customer deposits when PG&E has consistently used customer deposits to finance balancing account undercollections on which PG&E earns the three-month commercial paper rate.

PG&E disputes TURN's contention that changed circumstances have made large undercollections unlikely in the future. TURN has not shown that undercollections will disappear, only that historical levels may not persist. PG&E also disagrees with TURN's that the level of undercollections since PG&E

exited from bankruptcy in April 2004 presages future undercollections. PG&E states that too little time has elapsed since April 2004 to establish a clear trend.

PG&E maintains that the Commission's decisions in the last two SCE GRC proceedings are not applicable to PG&E because these decisions do not address PG&E's history of large undercollections. More relevant, in PG&E's opinion, is the Commission's decision in PG&E's Test Year 1996 GRC. There, TURN argued that customer deposits should be deducted from working cash. The Commission did not address this issue explicitly, but the Commission's decision utilized SP U-16 to compute working cash, which resulted in the exclusion of customer deposits from the working cash computation.

If the Commission adopts Aglet's and TURN's proposal to decrease working cash for customer deposits, PG&E argues that symmetry demands that the Commission increase working cash for balancing account undercollections. This would be consistent with SP U-16, which provides for symmetrical treatment of short-term assets and liabilities. Specifically, under SP U-16, interest-bearing short-term assets and liabilities are both excluded from the working cash calculation. Similarly, non-interest bearing short-term assets and liabilities are included in the working cash calculation. PG&E contends that all the factors cited by Aglet and TURN for including customer deposits in the working cash calculation apply equally to balancing account undercollections.

In similar vein, PG&E notes the treatment of nuclear fuel inventory by the Settlement. PG&E agreed to remove nuclear fuel from rate base, even though nuclear fuel inventory requires a permanent commitment of capital. PG&E contends that if customer deposits are used to reduce rate base on the theory that they represent a permanent source of capital, it is only fair that nuclear fuel be added to rate base because it requires a permanent commitment of capital.

PG&E disagrees with the amount of customer deposits forecasted by Aglet and TURN for 2007. Aglet forecasted $164.9 million based on the average of customer deposits during 2005. TURN forecasted $147 million based on the 2005 year-end customer deposits. PG&E argues that TURN's graph shows that deposit levels were decreasing in 2005, and that trend could continue. Thus, adopting either Aglet's proposal or TURN's proposal could require PG&E to pay 13% on money that PG&E might never receive.

PG&E notes that Aglet would allow PG&E to recover a rate of interest on customer deposits of 5.21%. PG&E states that short-term rates have been increasing. If interest rates continue to increase, PG&E would be required to pay more interest on deposits than it recovers in rates. The net effect would be a loss for PG&E equal to the difference between the short-term rate being paid on deposits and the amount recovered in rates.

ii. Discussion

As a preliminary matter, we find that the uncontested aspects of the Settlement Agreement's computation of working cash to be reasonable in light of the record, consistent with applicable law, and in the public interest. The only concerns we have regarding working cash pertain to the issues raised by Aglet and TURN, which we address below.

The largest issue regarding working cash is whether to adopt Aglet's and TURN's proposal to treat customer deposits as a reduction to working cash. We decline to adopt their proposal. The record shows that PG&E and the Settlement Agreement calculated working cash in accordance with SP U-16, which has been in effect since 1969. As such, we view the Settlement outcome on working cash as presumptively reasonable.

Aglet and TURN raise several arguments for why it is appropriate to depart from a key element of SP U-16. Perhaps their best argument is that the Commission's decisions in the two most recent GRCs for SCE departed from SP U-16 and deducted customer deposits from working cash. They assert that the Commission should treat PG&E the same as SCE. We disagree. Our review of Commission precedent reveals that SCE is somewhat of an aberration in this regard. In the last two years alone there have been numerous Commission decisions that relied on SP U-16 to determine working cash.[212]

The remaining arguments offered by Aglet and TURN have some merit, but so do PG&E's counter arguments. On the whole, we find that Aglet and TURN have not marshaled sufficient facts and arguments to overcome our presumption that Settlement Agreement's reliance on SP U-16 is reasonable.

For the preceding reasons, we find the Settlement outcome for customer deposits is reasonable in light of the record, consistent with Commission precedent, and in the public interest.

c. Lead-Lag Calculation of Working Cash

TURN proposes two changes to the lead-lag study, which together reduce PG&E's rate base by $5.286 million. We address each recommendation below.

i. Revenue Lag

(A) Position of the Parties

PG&E's lead-lag study used data from 2004 to calculate the revenue lag. TURN states that because there is variability in the revenue lag data, it is better to use a longer period to calculate an average value. TURN recommends

[212] See for example, D.05-12-020 and D.05-08-004.

averaging data for 2004 and 2005, which reduces revenue lag by 0.18 days. The adjustment would reduce rate base by $4.2 million.

PG&E opposes TURN's adjustment on the grounds that it mixes data from different years. PG&E maintains that it is the Commission's general practice to use data from a single year in the lead-lag study.

(B) Discussion

PG&E used 2004 data in all of its working cash calculations, including the revenue lag computation, unless special circumstances existed.[213] PG&E saw no special circumstances to use data outside of 2004 to determine the revenue lag.

We decline to adopt TURN's proposal to use data from both 2004 and 2005 to calculate the revenue lag. We agree with PG&E that multiple years should only be used if warranted by special circumstances, which are not present here.

TURN argues that there is variability in the data for revenue lag, but TURN offers no quantification of such variability. PG&E testified that there was only a slight change in data between 2004 and 2005.[214] Slight changes in data from year to year are common and not worthy of special treatment. Furthermore, TURN selectively chooses to use 2005 data in only part of the working cash calculation. This pick-and-choose approach would set a bad precedent and cause further disputes in the already complex matter of determining "leads and lags" in the working cash study.

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[213] Exhibit PG&E-2, pp. 12-12 to 12-13; Exhibit PG&E-18, p. 6-6, L: 28-29.

[214] 11 TR 721:22-24, PG&E/Jones.

ii. Savings Fund Lag

(A) Position of the Parties

PG&E's working cash calculation assumes zero lag days for the Company's matching contributions to the savings pool. TURN submits that the lag for the matching savings-fund contributions should be 16.81 days, the same as the lag for payroll less 0.49 days for float. Adopting TURN's recommendation would reduce rate base by $1.111 million.

PG&E responds that TURN's proposal is contrary to the Commission's treatment of this issue in PG&E's 1996 GRC:

> TURN recommends that savings fund contributions be accorded the same number of…lag days as payroll. TURN believes that, like payroll taxes (FICA), employee savings contributions are incurred at the same time labor cost is incurred. PG&E has agreed to make a similar adjustment for FICA…PG&E responds that, unlike FICA, it does not incur employee savings contributions until…the employee is paid. FICA is incurred over the period the obligation to the employee is incurred. PG&E makes a reasonable argument that FICA obligations are incurred differently from employee savings contributions. We will adopt PG&E's proposal. (D.95-02-015, 63 CPUC 2d 570, 617.)

PG&E concedes that its treatment of lag days for savings-fund contributions is not precise. Nevertheless, PG&E argues that its use of zero lag days is preferable to TURN's recommendation for two reasons. First, TURN's proposal is based on the average lag in wage payments, including performance incentive payments (PIP). The PIP extends the computed wage lag by taking into account PIP payments in mid-March of the following year. In contrast, matching savings-fund contributions are paid only on regular wages paid during the year (or in the first week of January of the following year). Thus, associating the savings-fund lag with the wage lag (including PIP) creates a lag that is too long.

Second, savings-fund contributions are front loaded towards the early part of the year. As with FICA taxes that stop when an employee reaches the wage limit for the year ($87,900 in 2004), PG&E's matching contributions to the savings fund stop when the employee reaches the 401(k) limitation.

If the Commission adopts TURN's proposal for computing the lag on savings-fund contributions, PG&E states that the proposal would need to be refined to better account for "front-loading."

(B) Discussion

TURN seeks to adjust the lag days for PG&E's matching contributions to the savings fund so that the savings-fund lag matches payroll lag. Adopting TURN's proposal would change the savings-fund lag from zero to 16.81 days,[215] reduce PG&E's rate base by $1,111,000, and reduce PG&E's revenue requirement by approximately $144,000 in 2007.

We agree with the logic of TURN's proposal. PG&E makes it matching contributions to the savings fund at the same time it pays wages. Thus, the two should be treated similarly in the working cash calculation.

Although we agree with TURN's proposal, PG&E raises two valid technical objections that we cannot resolve here. First, PG&E represents that savings-fund contributions are paid only on regular wages and not on PIP, so using the payroll lag as proposed by TURN (which includes PIP paid in March of

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215 Exhibit TURN-1, p. 86.

the following year) would overstate the lag.[216] Second, PG&E testified that savings-fund contributions (which are a match of employee contributions) tend to be front loaded during the year because of IRS limitations and otherwise.[217] PG&E's matching contributions to the savings fund plan end when the employee reaches the 401(k) limitation. TURN's proposal overstates lag because it assumes the payroll lag and the savings-fund contribution lag are the same.

There is an insufficient record to determine by how much the adopted revenue requirement reduction of $144,000 should be reduced to reflect PG&E's two corrections. We conclude that because $144,000 is insignificant in relation to PG&E's multi-billion revenue requirement adopted by today's Opinion, and because the $144,000 should be reduced for the previously stated reasons, that the appropriate reduction to PG&E's rate base and revenue requirement is already reflected in rate base and revenue requirement adopted by the Settlement, both of which are lower than what PG&E requested in A.05-12-002.

In its next GRC proceeding, PG&E shall incorporate into the calculation of working cash a lag for employer savings-fund contributions in a manner consistent with today's Opinion.

The resolution of the savings-fund-contribution issue by today's Opinion is not inconsistent with D.95-02-015. There, the Commission appears to have addressed the lag for savings-fund contributions by employees. Today's Opinion addresses savings-fund contributions by the employer. Thus, the two decisions address somewhat different issues. Further, PG&E concedes in the instant proceeding that "its current treatment [of the employer's matching

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[216] Exhibit PG&E-18, p. 6-8, L: 4-11.

[217] 11 TR 750:4-18, PG&E/Jones.

savings-fund contributions] may not be a precise computation of the ratemaking lag.[218]" In light of PG&E's concession, the facts and circumstances in the instant proceeding warrant a different outcome than D.95-02-015.

8. Depreciation Expense

The purpose of depreciation expense for ratemaking purposes is to allow a utility to recover the costs it incurs to buy, install, and remove assets over the useful life of the assets. The Commission determines depreciation expense on an accrual basis using the straight-line, remaining life method described in Commission Standard Practice (SP) U-4, *Determination of Straight-Line Remaining Life Depreciation Accruals,* dated January 3, 1961. This method uses the following formula to calculate the annual depreciation expense accrual:

$$\textbf{Depreciation Expense} = \frac{\text{Plant Balance} - \text{Reserve} - \text{Gross Salvage} + \text{Cost of Removal}}{\text{Remaining Service Life of Asset(s)}}$$

The components of the depreciation expense accrual are as follows:

Plant balance is equal to the original cost of assets (other than land) used to provide service to customers.

Reserve is the accumulated depreciation expense recorded to date for existing plant-in-service.

Gross salvage is the estimated future scrap value that will be realized when existing plant-in-service is retired.

Removal cost is the estimated future cost to remove existing plant-in-service.

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[218] Settlement Motion, p. 239.

Remaining life is the expected average remaining life of plant-in-service.

In A.05-12-002, PG&E requested $1.024 billion for depreciation expense in 2007 based on SP U-4 and the parameters in PG&E's testimony (e.g., remaining life and gross salvage).[219] The only parties to contest PG&E's request were TURN and DRA. Both parties disagreed with PG&E's forecast of net salvage.[220] DRA also contested PG&E's proposal for refunding excess accumulated depreciation for fossil generation decommissioning.

a. Issues Raised by DRA

i. The Settlement Agreement

PG&E used SP U-4 to forecast depreciation expense in 2007. DRA agreed with this method, but advocated higher net salvage rates.[221] DRA's proposal was based on its observation that PG&E in recent years has collected around $180 million annually for removal costs but has spent less than $80 million annually. DRA's proposed net salvage rates would allow PG&E to collect

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[219] Exhibit PG&E-2, p. 9-12 to p. 9-16, and Table 9-2.

[220] Net salvage is gross salvage less removal costs. Net salvage can be positive or negative. For most retirements, removal costs are much higher than gross salvage value, resulting in negative net salvage.

[221] The net salvage rate is net salvage divided by the original cost of the plant being retired. The net salvage rate is often negative. For example, a utility pole that cost $100 to install in 1960 and $150 to remove and retire in 2000 will have a net salvage of -$150 and a net salvage rate of -150% [-150% = -150/100]. If this asset class has a plant balance of $600 million in 2000 and the previously described net salvage relationship applies to the entire account, the depreciation expense recovered in rates over the remaining life of the plant would be $1,500 million less the depreciation reserve. The $1,500 million is composed of $600 million for the current plant balance and $900 million (150% of $600 million) for the expected future removal costs (i.e., negative net salvage).

$9.6 billion of the $12.3 billion that PG&E estimated it would need for negative net salvage over the next 30 years for existing Distribution assets.

PG&E responded that DRA used improper techniques to reduce negative net salvage. For example, PG&E's depreciation study used 15 years of historical data. Although DRA used the same data, PG&E claims that DRA excluded data for outlier years that reduced negative net salvage, but DRA did not exclude data for outlier years that went the other way. Similarly, DRA compared PG&E's negative net salvage to other utilities when the comparison resulted in a lower revenue requirement for PG&E, but DRA omitted comparisons that went the other way.

The Settlement Agreement adopts most of DRA's proposed net salvage rates. The following Table compares the Settlement with PG&E's and DRA's positions on depreciation expense:

2007 Depreciation Expense
($ millions)

	2006 Authorized	**Comparison Exhibit**		**Settlement 2007**	**Variances Increase/(Decrease)**		
		PG&E 2007	**DRA 2007**		**Settlement vs. 2006**	**Settlement vs. PG&E**	**Settlement vs. DRA**
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
Depreciation	839	1,024	939	942	103	(82)	3

(**Source**: Settlement Agreement, Appendix A, p. 23, L: 31.)

As shown in the above Table, the Settlement Agreement is very close to DRA's position on depreciation expense. Virtually all of the difference between PG&E's request and amount adopted by the Settlement is attributable to those DRA net salvage rates adopted by the Settlement.

The other issue contested by DRA concerned the refund of excess accumulated depreciation for fossil generation decommission costs. DRA and PG&E agreed there should be a refund, but disagreed on the amount of interest that should accrue on the refund. PG&E argued that the refund has been carried in the depreciation reserve for fossil decommissioning. This has had the effect of reducing rate base, with a corresponding benefit to ratepayers equal to the annual pre-tax rate of return of approximately 13%. DRA proposed that ratepayers receive an additional 5% interest on the over-accrual.

In rebuttal, PG&E maintained that customers have benefited from the reduced rate of return on rate base and will continue to do so until the over collection is refunded. The Settling Parties agree that ratepayers should retain the rate base reduction but not receive 5% interest on top of that.[222]

ii. Discussion

We find that the amount of depreciation expense adopted by the Settlement Agreement is reasonable in light of the record. PG&E submitted a comprehensive depreciation study, and the parties collectively submitted more than 900 pages of testimony on depreciation expense. This substantial record readily supports PG&E's requested depreciation expense, except for the net salvage component of depreciation.

With regards to net salvage, DRA has demonstrated that PG&E's net salvage rates are too low, since in recent years PG&E has collected about $180 million annually for removal costs but has spent less than $80 million

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[222] Settlement, para. 42.

annually.[223] In A.05-12-002, PG&E requested $379 million annually for removal costs, but projected it would spend only $88 million annually. The Settlement Agreement authorizes PG&E to recover $299 million annually, which is very close to DRA's recommendation of $296 million.[224] Although the Settlement still has a gap of $211 million between the amount of future removal costs that PG&E will collect in rates annually and the amount expended annually, this gap is normal and reasonable. As noted by PG&E, the annual accrual of future removal costs will exceed annual expenditures when, as here, new assets are being added faster than old assets are being removed and projected future removal costs are higher than current removal costs due to anticipated inflation.[225]

We also find that the amount of depreciation expense adopted by the Settlement Agreement is consistent with the law. Because the Settlement allows PG&E to recover a reasonable amount of depreciation expense, the Settlement is consistent with the Commission's authority under § 795 to set "proper and adequate rates of depreciation…[for] each public utility."

Finally, we conclude that it is in the public interest to authorize PG&E to recover the amount of depreciation expense set forth in the Settlement. The provision of gas and electric service to the public requires substantial investment. Utilities must recover the reasonable costs they incur to make such investments, including depreciation expense, in order to provide gas and electric service. The Settlement Agreement allows PG&E to recover its reasonable depreciation

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[223] Exhibit DRA-16, p. 16-10.

[224] Settlement Motion, p. 247.

[225] Settlement Motion, p. 270.

expense, including a reasonable amount of removal costs, and thereby enables PG&E to provide vital gas and electric service to the public.

We also find reasonable the Settlement's provisions on the interest owed by PG&E on a pending refund of excess accumulated depreciation for fossil decommissioning expense. We agree with PG&E's position that fossil decommissioning expense is part of the depreciation reserve and reduces rate base. Ratepayers have, in effect, earned interest on the excess decommissioning expense at a rate equal to PG&E's authorized rate of return, and will continue to do so until the over-collection is refunded.[226] Thus, it is unnecessary for PG&E to pay additional interest on the refund as originally proposed by DRA.

b. Depreciation Issues Raised by TURN

TURN makes three proposals regarding the net salvage component of PG&E's depreciation expense accrual. First, TURN proposes that PG&E establish a regulatory liability for the money that PG&E has collected in rates for future removal costs but has not yet spent. Second, TURN asks the Commission to set PG&E's depreciation expense using what TURN calls "normalized net salvage" instead of the current straight-line remaining life method. Finally, TURN believes that PG&E should provide in its next GRC a depreciation study that uses the net present value approach described in SFAS No. 143 to determine future removal costs. We address each of TURN's proposals below.

i. Regulatory Liability for Removal Costs

Under SP U-4, the future cost to remove existing assets is recovered as part of depreciation expense on a straight-line basis over the average expected life of

[226] Exhibit PG&E-18, p. 3-7, L: 1-7.

the assets. Thus, by the time an asset is retired, the utility has, on average, recovered the entire cost to remove the asset. Removal costs recovered in depreciation expense are part of the depreciation reserve and reduce rate base.

By the end of 2005, the cumulative amount of removal costs that PG&E had collected in rates exceed actual expenditures by $2.1 billion. Most of the $2.1 billion of pre-funded removal costs will not be spent for many years. Under the Settlement Agreement, the amount of removal costs that PG&E collects in rates will continue to exceed actual expenditures by approximately $211 million annually. Thus, by the end of 2010, PG&E will have collected more than $3.0 billion for removal costs that it has not yet spent.

For external financial reporting purposes, PG&E reports pre-funded removal costs as a regulatory liability pursuant to SFAS 71. Under generally accepted accounting principles (GAAP), a regulated entity such as PG&E must record a regulatory liability for future costs when (1) the regulator has provided rates to recover specified future costs, and (2) the regulated entity must return the funds collected in rates if the future costs do not materialize. The obligation to return the funds can be fulfilled either by future rate reductions or by paying other future costs with no corresponding effect on future rates.

(A) Position of the Parties

(1) TURN

TURN recommends that PG&E record in its regulatory books a regulatory liability for pre-funded removal costs. Excluded from TURN's recommendation are asset retirement obligations (AROs) that PG&E reports on its external financial statements pursuant to SFAS 143.[227] TURN does not explain why AROs are excluded from its proposal, even though PG&E's AROs are substantial.[228]

The basis for TURN's proposal is its concern that PG&E will not use the $2.1 billion of pre-funded removal costs that it has already collected in rates to pay for removal costs. TURN believes that recording a regulatory liability on PG&E's regulatory books will help to ensure that PG&E either uses the $2.1 billion for its intended purpose or returns these funds to ratepayers.

TURN recognizes that PG&E already reports the $2.1 billion of pre-funded removal costs as regulatory liability on its external financial statements pursuant to SFAS 71. In doing so, PG&E has acknowledged that the Commission expects PG&E to either use the $2.1 billion to pay for future removal costs or return these funds to ratepayers. However, there is no Commission decision that explicitly establishes this requirement. TURN believes it is necessary for the Commission to explicitly create a regulatory liability for pre-funded removal costs given PG&E's testimony that accumulated depreciation represents capital that belongs to investors rather than ratepayers.[229]

(2) Aglet

Aglet supports TURN's recommendation. Aglet states that TURN has identified a situation where ratepayers have pre-paid billions of dollars for removal costs but won't receive the benefit for decades. Given this situation, Aglet believes the Commission should explicitly order that PG&E's pre-funded

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[227] AROs are legal obligations to incur future costs to remove existing assets.

[228] PG&E's SEC Form 10K for 2005 shows that as of December 31, 2005, that PG&E's regulatory liability for AROs was $538 million, which was in addition to the regulatory liability of $2.141 billion for pre-funded removal costs.

[229] Exhibit TURN-53, Response to Q/A 0001-73(h) and (i); 27 RT 2609-10, PG&E/White.

removal costs must be spent on removal costs or returned to ratepayers. Although there is only a small probability that ratepayers might lose these funds in a future sale of the utility or other circumstances, Aglet contends that the stakes are too high for the Commission to ignore the issue.

(3) SCE

SCE intervened in this proceeding for the limited purpose of addressing the depreciation policies advocated by TURN. SCE takes no position on the specific depreciation rates or PG&E's revenue requirement.

SCE maintains that a regulatory liability is an accounting device that is limited to external financial reporting. The Commission has no need to establish regulatory liabilities for ratemaking purposes, according to SCE, because the Commission already has all the authority it needs to oversee and control the disposition of pre-funded removal costs.

(4) PG&E and the Other Settling Parties

PG&E believes it is unnecessary for the Commission to create a regulatory liability because the pre-funded removal costs will eventually be incurred regardless of (1) how PG&E accounts for these costs, or (2) any future changes to the regulatory framework under which PG&E operates.

(B) Discussion

PG&E receives a huge amount of capital from ratepayers to pre-fund future removal costs. The record shows that as of the end of 2005, the cumulative amount of removal costs that PG&E had collected in rates exceeded cumulative expenditures by $2.1 billion. The Settlement allows this figure to grow by $211 million annually during 2007-2010.[230]

The *quid pro quo* for ratepayers is that PG&E will use the money it collects to pre-fund future removal costs to pay for removal costs. PG&E has recognized this regulatory bargain in its external financial statements where it reports a regulatory liability for pre-funded removal costs. Under SFAS 71, pre-funded removal costs can be reported as a regulatory liability only if the funds will be spent on removal costs or returned to ratepayers.

TURN and Aglet recommend that PG&E be required to classify pre-funded removal costs as a regulatory liability for ratemaking purposes. We agree for several reasons. First, doing so accurately reflects the regulatory bargain. Second, it is consistent with GAAP as demonstrated by the way PG&E reports pre-funded removal costs on its external financial statements. Finally, it provides an extra measure of assurance that PG&E will only use the amounts that it collects to pre-fund removal costs for their intended purpose.

SCE argues that it is unnecessary to classify pre-funded removal costs as a regulatory liability for ratemaking purposes. We disagree. PG&E has accumulated $2.1 billion for removal costs that will not be incurred for years or decades. Under the Settlement, this amount will continue to grow at the rate of more than $200 million per year. With the stakes so high and the actual incurrence of the removal costs far in the future, we conclude that it is appropriate to establish the regulatory liability as a reasonable protection of ratepayers' interest in making sure the huge amount of money collected for

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[230] Settlement Motion, p. 247 (difference between Settlement revenue requirement for future removal costs and projected asset removal expenditures in 2007).

removal costs is either spent for that purpose or returned to ratepayers (either in the form of a rate reduction or as an offset to other costs). Our action today will cause no harm to PG&E's shareholders, since PG&E already reports a regulatory liability for external financial reporting purposes.

We are also concerned about the consequences of our not adopting a regulatory liability. Pursuant to SFAS 71, a necessary condition for reporting a regulatory liability on external financial statements is a "rate action" that imposes a liability on a regulated entity.[231] The issue of whether PG&E should create a regulatory liability for pre-funded removal costs is squarely before us. If we decline to require PG&E to record a regulatory liability for ratemaking purposes, there will be less reason for PG&E to do so for external financial reporting purposes. We believe that such an outcome would undermine the regulatory bargain described previously, which is not our intent.

Our adoption of a regulatory liability for PG&E's pre-funded removal costs is consistent with our resolution of the same issue in the most recent SCE GRC proceeding. There, we held that:

> TURN's request that the balance of funds collected for cost of removal…be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted. The balance…is substantial, amounting to $2.1 billion as of the end of 2004. This balance is already recognized as a regulatory liability for financial reporting purposes. SCE has not demonstrated any potential harm to the company…Formal recognition of our ratemaking responsibilities is a reasonable course of action and will establish regulatory certainty regarding ratemaking

231 SFAS 71, para. 11.

> treatment and principles that all parties generally agree is appropriate. (D.06-05-016, *mimeo.*, p. 204.)

We see no reason to treat PG&E differently from SCE.

We emphasize that our adoption of a regulatory liability for PG&E's pre-funded removal costs in no way prejudges how we might treat the regulatory liability if there is ever partial or full deregulation. We recognize, however, that if such an event were to occur, and PG&E has future removal costs at that time, PG&E may be entitled to keep some or all of the pre-funded removal costs in existence at that time to pay for future removal costs.

As noted earlier, PG&E reports a substantial regulatory liability for AROs on its external financial statements. We concur with this accounting. We invite parties to address in the next GRC whether it is necessary and reasonable to explicitly order PG&E to establish a regulatory liability for AROs.

ii. TURN's Normalized Net Salvage Proposal

PG&E estimated the future removal costs included in depreciation expense in accordance with the instructions in SP U-4. Using this guidance, PG&E first determined the ratio of recorded removal costs to recorded asset retirements for the last 15 years. PG&E multiplied this ratio by the current gross plant to project future removal costs. The projected future removal costs were then spread evenly over the average remaining life of existing plant-in-service.

Using the previously described method, PG&E estimated that it will cost approximately $12 billion in future-year dollars to remove its entire gas and electric distribution system. PG&E spread this amount over 30.7 years to arrive at an annual accrual for future removal costs of $379 million.

DRA agreed with the methodology that PG&E's used to estimate future removal costs, but DRA disagreed with some of the parameters used by PG&E.

Using its own parameters, DRA recommended that PG&E be allowed to recover $296 million of removal costs in 2007.

TURN disagreed with the methodology used by PG&E. TURN recommends that PG&E be authorized to recover removal costs based on what TURN calls the "normalized net salvage approach." Under TURN's approach, the amount of removal costs recovered in rates would equal the annual average of PG&E's out-of-pocket costs for the previous three years or five years. TURN's proposal would allow PG&E to recover $88 million in 2007 if a three-year period is used, and $68 million if a five-year period is used.

The Settlement Agreement adopts removal costs of $299 million in 2007 using PG&E's method for forecasting removal costs combined with most of the parameters recommended by DRA. The Settlement is $81 million less than PG&E requested and very close to DRA's recommendation of $296 million. The Settlement does not incorporate any elements of TURN's recommendation.

(A) Position of the Parties

(1) TURN

TURN has two objections to the way removal costs are estimated in the Settlement Agreement. First, the Settlement forecasts removal costs in future-year dollars, and then spreads the future costs over the service life of plant-in-service. Because of inflation, future removal costs will be much higher than today. So, if an asset in 2007 has an expected service life that extends to 2037, ratepayers in 2007 will use 2007 dollars to pay removal costs stated in year 2037 dollars, ratepayers in 2020 will pay in 2020 dollars, and so on. Thus, ratepayers in 2007 will pay more in real dollars than ratepayers in 2020 and other future years. TURN believes this is illogical and unfair to ratepayers in 2007. TURN also contends that forcing ratepayers to pay for inflation that has not yet occurred is why PG&E has accumulated $2.1 billion in unspent future removal costs, a figure that will increase by $211 million annually under the Settlement.

TURN's second concern is that the method used to estimate future inflation implicitly assumes that future inflation will match historical inflation. If the implicit inflation rate is too high, current customers will pay more than they should for future removal costs. If the forecasted inflation rate is too low, current customers will pay less than they should for future removal costs. Either way, ratepayers will pay too much for inflation or too little.[232]

TURN represents that SP U-4 does not mandate the use of inflation in the determination of removal costs. Rather, SP U-4 calls for removal costs to reflect "anticipated changes in labor costs for the immediate future.[233]" TURN asserts that including inflation from the distant future in the current accrual for removal costs is inconsistent with the emphasis in SP U-4 on "the immediate future."

For the previous reasons, TURN recommends that the Commission eliminate inflation from the determination of removal costs. TURN proposes that removal costs for this GRC cycle be based on a rolling three-year or five-year average of PG&E's recorded removal costs. TURN calls this alternative the "normalized net salvage approach." PG&E's revenue requirement for removal costs in 2007 would be $88 million based on a three-year average of historical removal costs or $63 million based on a five-year average.

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232 TURN adds that to the extent future inflation is assumed to be greater than zero, and to the extent current rates include future removal costs stated in nominal dollars, there will always be an overpayment that is occurring from a real-dollar perspective.

233 Exhibit PG&E-54, p. 40.

(2) PG&E and the Other Settling Parties

The Settlement Motion contains the following table to show the difference between the Settlement Agreement and TURN's proposal. The table shows on an illustrative basis (1) the 2007 revenue requirement for removal costs using the Settlement's SP U-4 accrual method and TURN's normalized net salvage method; (2) the approximate 2007 rate reduction from the reduction in rate base attributable to pre-funded removal costs; (3) the net 2007 revenue requirement for removal costs; and (4) projected expenditures for removal costs in 2007.

Comparison of 2007 Cost-of-Removal (COR) Revenue Requirement (In Millions)		
	Settlement [A]	**TURN [B]**
1. 2007 COR Revenue Requirement	**299**	**88**
2. Less: Rate Benefit from Reduced Rate Base Associated for Pre-Funded COR **[C]**	**(150)**	**(150)**
3. Net 2007 COR Revenue Requirement (Line 1 - 2)	**149**	**(62)**
4. Projected COR expenditures (2007) **[D]**	**88**	**88**
5. Net 2007 COR Revenue Requirement compared with 2007 projected COR expenditures (Line 3 - 4)	**61**	**(150)**
<u>Notes</u>		
[A] Traditional SP U-4 accrual method.		
[B] Normalized net salvage method based on the 3-year average of 2002-2004 recorded removal costs (PG&E-2 WP, Chapter 10, p 10-11 to 10-211).		
[C] Rate reduction based on $2.1 billion of pre-funded removal costs (and corresponding reduction to rate base) less deferred taxes (approximately $800 million) multiplied by PG&E's pre-tax rate of return (approximately 13.1%).		
[D] Projected 2007 COR expenditures based on the 3-year average of 2002-2004.		

The above Table shows that under the Settlement Agreement, ratepayers will pay $299 million in 2007 to pre-fund future removal costs and receive a benefit of $150 million from the rate base reduction for pre-funded removal costs.

The net cost to ratepayers in 2007 is $149 million, which is approximately $61 million more than forecasted removal expenditures of $88 million in 2007.

PG&E states that the Settlement's forecast of removal costs of $299 million is a conservative estimate. To demonstrate this point, the Settlement Motion provides an example based on PG&E's testimony that it had 2.3 million utility poles with an average replacement cost in 2007 of approximately $6,000 per pole. On average, current removal costs constitute 10% of replacement costs, or $600 per pole. The Settlement adopts future removal costs of $1.52 billion for existing poles over the next 30.7 years. This equates to an average future removal cost of under $700 per pole (i.e., $1.52 billion divided by 2.3 million poles) for recovery over the next 30.7 years. This also equates to a conservative inflation rate of less than 0.5% annually (i.e., an increase from $600 to $700 over the 30.7-year average remaining life). Thus, TURN's concerns regarding enormous over-accruals using SP U-4 are unfounded.

TURN's proposal would have ratepayers pay only the historical three-year average cost of $88 million. PG&E asserts that the three-year average does not take into account the far greater quantity of assets that will be removed in the future at a far higher unit cost. It also ignores the estimated $150 million annual rate reduction from the $2.1 billion reduction to rate base for pre-funded removal costs. As a result, TURN's proposal would provide a net rate reduction of $62 million ($88 million - $150 million) due solely to an accounting change.[234]

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[234] Stated otherwise, if the normalized net salvage approach had been in effect all along there would be no pre-funded reserve and no rate base reduction. Rates for the current vintage of customers would be $150 million higher if that were the case.

PG&E believes the $62 million rate reduction unfairly benefits current ratepayers at the expense of future ratepayers.

PG&E disagrees with TURN's position that reflecting future cost levels in current depreciation is unfair to current ratepayers. TURN states:

> If "intergenerational equity" is a guiding principle on such issues, the Commission needs to assign the costs of inflation to the generation of ratepayers that will pay those costs with inflated dollars. In other words, let current ratepayers bear the costs of current inflation, and leave the 2030 inflation to be borne by ratepayers in 2030. (TURN Comments, p. 112.)

PG&E argues that TURN's position conflicts with SP U-4, which states that the straight-line accrual method for depreciation used by DRA and PG&E meets the objective of an equitable sharing of costs.[235]

PG&E disputes TURN's argument that SP U-4 does not mandate depreciation rates that include future inflation for removal costs. Chapter 7 of SP U-4 includes numerical examples and tables that illustrate the calculation of removal costs. Since the adoption of SP U-4 in 1961, many depreciation studies have been completed and numerous Commission decisions have been issued that utilize the method described in SP U-4. PG&E maintains that it adhered to this guidance and precedent.

(3) SDG&E and SCG

SDG&E and SCG (together, Sempra) joined the Settlement Agreement for the sole purpose of supporting the use of SP U-4 to compute removal costs.

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235 Exhibit PG&E-54, p. 5, para. 2.

Sempra states that TURN's proposed net-salvage approach is premised on TURN's allegation that PG&E will never spend the money for removal costs at the level it is collecting from ratepayers. Sempra maintains that TURN did not provide any evidence to support its allegation.

Sempra also disputes the following statement by TURN that SP U-4 prohibits the use of inflation in determining removal costs:

> SP U-4 calls for basing predicted future cost of removal by "reflecting anticipated changes in labor cost for the immediate future." Including inflation costs going some years, even decades, into the future is inconsistent with the emphasis of SP U-4 on the "immediate future." (TURN's Comments filed on Sept. 20, 2006, p. 126.)

Sempra contends that TURN misconstrues SP U-4. TURN interprets the term "immediate future" to mean that future inflation is not prescribed in SP U-4. That is an incorrect interpretation of SP U-4, according to Sempra.

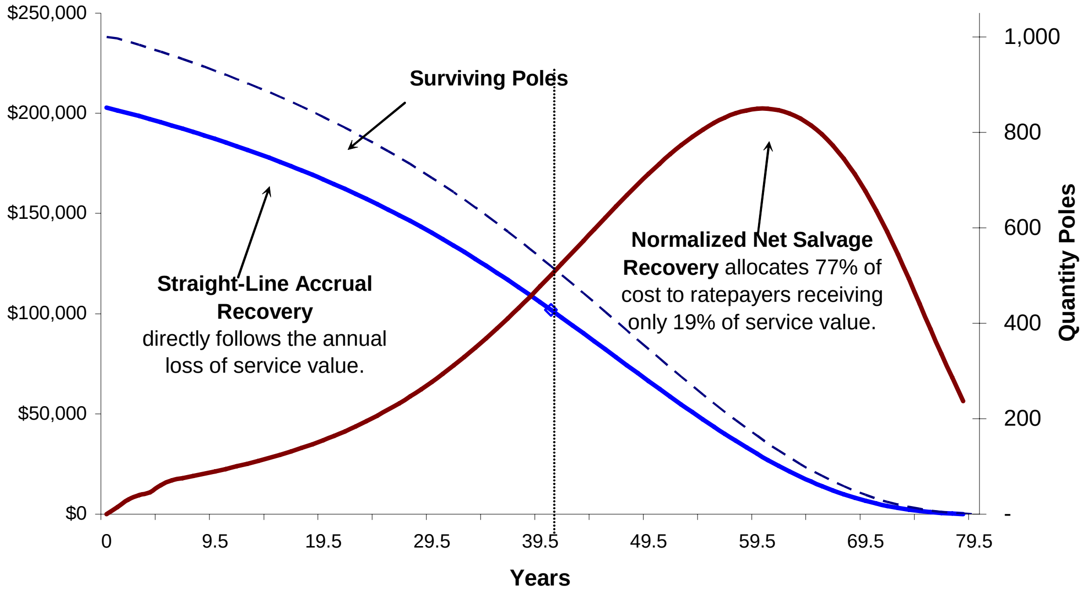
(4) SCE

SCE provides an example to illustrate the deferral of removal costs under TURN's proposal. Assuming $1,000 of removal costs and a 10-year asset life, TURN's method would not allocate any costs to ratepayers during the asset's life. Instead, after the asset retires in year ten, ratepayers who did not benefit from the asset would bear the entire cost of removal over the ensuing three-year or five-year period. In contrast, the traditional SP U-4 accrual method allocates net salvage costs of $1,000 over the asset's service life and to those ratepayers who receive the benefits of the asset.

SCE states that the recovery pattern for a single asset would also hold for a group of assets. SCE compared the cost recovery patterns for a group of utility poles that follow PG&E's service life and retirement dispersion characteristics.

As shown below, the SP U-4 accrual method recovers removal costs in a manner consistent with the pattern of the surviving poles' declining service value; TURN's normalized net salvage method would not.

Comparison of Removal Cost Recovery Pattern



Although only about 20% of the poles' collective service value remains after the first 40 years (area to the right of the vertical line), TURN's approach assigns nearly 80% of the removal costs to the ratepayers receiving service after this point. That is, the ratepayers who receive the last 20% of the service value of the poles would bear about 80% of the removal costs for all of the poles.

SCE argues that the above graph shows that TURN's pay-as-you-go approach shifts cost responsibility from current customers, who enjoyed the benefit of the asset's service value, to future customers. SCE claims that TURN presents no evidence to justify such a drastic change in Commission policy.

SCE claims that TURN wrongly asserts that the intent of SP U-4 is to exclude inflation from the computation of removal costs. SCE reads SP U-4 as advocating the widely-held practice of using the ratio of recorded net salvage costs to recorded plant retirement amounts (i.e., net salvage ratios) to estimate future removal costs. Consequently, SP U-4 incorporates an inherent inflation impact because of the time difference between the recorded costs reflected in the numerator and denominator.

(B) Discussion

The issue before us is whether to adopt TURN's proposed "normalized net salvage allowance approach" for setting rates to recover asset removal costs. Under TURN's approach there will be no recovery of removal costs until after assets have retired and the associated removal costs have been incurred. TURN's method is, in effect, a form of cash-basis accounting.[236]

TURN's proposal is a marked departure from the current accrual accounting for removal costs. The purpose of using accrual accounting is to allocate to current ratepayers their *pro rata* share of the costs that will eventually be incurred to remove those assets that are currently being used to provide utility service. This treatment is in harmony with GAAP, the USOA, and long-standing Commission practice under SP U-4.[237]

Accrual accounting for removal costs is fair to ratepayers because it ensures that ratepayers pay for the removal costs of those assets that serve them, and pay no removal costs for assets that do not serve them. On the other hand,

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[236] Exhibit PG&E-20, p. 11; Exhibit SDG&E-SCG-1, pp. 8-9; Exhibit SCE-1, pp. 11-15; and Exhibit TURN-3, p. 48.

[237] FERC USOA, General Instruction 11; SP U-4, p. 5.

TURN's proposal would require ratepayers to pay for removal costs incurred in prior years for assets that are no longer in service. As a matter of equity, we believe that ratepayers should pay only for those assets that currently serve them. TURN's proposal fails this test.

Although TURN's proposal is flawed, TURN argues that the accrual method is even worse. TURN's main objection is that the accrual method requires ratepayers to pay for inflation that has not yet occurred. There is some merit to TURN's objection. TURN has shown that the accrual method front loads removal costs in terms of real dollars. On the other hand, the Settling Parties have demonstrated with their pole example, *supra*, that the accrual method set forth in SP U-4 (and as implemented by PG&E) results in a conservative projection of future inflation that probably understates future removal costs in nominal dollars. The understatement of future removal costs offsets, at least in part, the front loading of future removal costs in terms of real dollars.

TURN also objects to the accrual method because it relies on 30-year projections of future removal costs that will likely prove to be inaccurate, and thereby result in current ratepayers paying more or less than they should. TURN is undoubtedly correct, but its objection also applies to other elements of depreciation expense, including service lives, as SP U-4 explicitly recognizes.[238] Indeed, TURN's objection applies to most elements of future test-year ratemaking. We conclude that because we endeavor to use reasonable assumptions to determine depreciation expense, including removal costs, and because we update these assumptions in every GRC proceeding, our use of

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[238] Exhibit PG&E-54, pp. 7-8.

projected future removal costs for ratemaking purposes is not unfair to current ratepayers. Moreover, because SP U-4 tends to understate future removal costs for the reasons described previously, it is unlikely that ratepayers will pay too much for future removal costs in terms of nominal dollars.

Next, TURN argues that the following sentence in SP U-4 shows that the Commission did not intend for removal costs to include future levels of inflation:

> Predicted future cost of removal should be based on a reasonable projection of **recent experience** reflecting anticipated changes in labor costs **for the immediate future**. (Exhibit PG&E-54, SP U-4, p. 40. Emphasis added.)

Parenthesis We find that TURN's interpretation of SP U-4 is not supported by the tables in SP U-4 which illustrate what was intended by this statement. The record shows that PG&E calculated future removal costs in conformity with the detailed instructions and illustrative tables set forth in SP U-4.[239]

For the preceding reasons, we are not persuaded that there is a need to abandon our long-held practice of using SP U-4 to determine the removal cost component of depreciation expense. Although we will retain our current practice for the time being, we are concerned about the large and growing balance of pre-funded removal costs, which currently exceeds $2.1 billion. We encourage TURN, DRA, and the others to carefully analyze pre-funded removal costs in the next GRC proceeding. To aid in this analysis, we will require PG&E to provide the following information in its next GRC proceeding:

- The then-current balance of pre-funded removal costs.

239 C*ompare* Exhibit PG&E-54, pp. 37-39 with Exhibit PG&E-2 WP10, pp. 10-8, 10-16, 10-23, and 10-30.

- A year-by-year projection of (1) when the then-existing balance of pre-funded removal costs will be consumed, and (2) the implicit inflation rate for future asset removal costs.
- A five-year projection of the year-end balance of pre-funded removal costs showing for each year the gross additions to the balance, gross expenditures for removal costs, and the net change in the balance of pre-funded removal costs.

iii. Net Present Value Depreciation Study

(A) Position of the Parties

(1) TURN

TURN argues that the traditional accrual method for recovering future removal costs is flawed because it is based on nominal dollars instead of real dollars. To correct this perceived flaw, TURN recommends that PG&E provide in its next GRC an estimate of future removal costs using the net-present-value approach described in SFAS 143.

TURN states that its recommendation is consistent with the Commission's decision in the recent SCE GRC proceeding. There, the Commission ordered SCE to provide in its next GRC a depreciation study that includes (1) a detailed analysis justifying the reasonableness of applying the method proposed at that time by SCE for determining removal costs, (2) an analysis of the effects of past inflation on SCE's proposed cost of removal rates, and (3) a justification of the implicit inflation rates reflected in SCE's proposed removal rates.[240]

TURN believes that its recommendation is consistent with two accounting pronouncements: SFAS 143 and FASB Interpretation No. 47 (FIN 47). Together, these two pronouncements require PG&E to report on its external financial

[240] D.06-05-016, *mimeo.*, pp. 205-210 and COL 33.

statements the "fair value" of PG&E's legal obligation to incur future removal costs.[241] These legal obligations are referred to as "asset retirement obligations" (AROs) and constitute only a fraction of PG&E's estimated future removal costs. In general terms, the fair value of AROs is the current market value of future removal costs or, when market value cannot be ascertained, the present value of future removal costs. PG&E used the present-value approach for its AROs.

TURN asserts that SFAS 143 and FIN 47 demonstrate that the accounting profession is moving towards a net present value approach for accruing all future removal costs. TURN also contends that because PG&E has successfully implemented SFAS 143 and FIN 47, PG&E should be able to determine the net present value of all of its future removal costs, not just the AROs that are the subject of SFAS 143 and FIN 47.

(2) PG&E and the Other Settling Parties

PG&E opposes TURN's proposal to require PG&E to submit in its next GRC proceeding a study showing the present value of all future removal costs. PG&E believes the Commission should wait until it has received and reviewed SCE's study to determine if a similar study is needed for PG&E. If, as PG&E expects, the SCE study shows that the implicit inflation rates are very conservative, there would be no need for PG&E to incur the additional expense of preparing a study.

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[241] SFAS 143 and FIN 47 require PG&E to record an ARO at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset.

PG&E believes the record in the current proceeding shows that the traditional method for projecting future removal costs in SP U-4 understates future inflation and thereby results in a conservative estimate of future removal costs. If the understated removal costs were then discounted back to the present, the result would be a fictional present value that is less than current removal costs. PG&E argues that because such a study would not reflect reality, it would have no use and would be a waste PG&E's and the Commission's resources.

PG&E disputes TURN's suggestion that PG&E's successful implementation of SFAS 143 and FIN 47 shows that PG&E can determine the net present value of all removal costs. PG&E states that SFAS 143 and FIN 47 affected only a handful of accounts, not the entire spectrum of the GRC filing, which would be far more complex and subjective. Unlike SP U-4, which has a long history of interpretation and application, there is no detailed set of rules for determining the net present value of future removal costs. Because PG&E would be preparing the study with little guidance, the result is likely to be controversial.

(3) SCE

SCE asserts that TURN's proposal is inappropriate. This is because the present-value calculation prescribed by SFAS 143 uses the following parameters that are unsuitable for ratemaking: (1) the estimated cost to permanently retire, remove, and/or dispose of tangible assets; (2) estimated escalation rates; (3) a provision for third-party profits; (4) varying future scenarios weighted by the probability of occurrence; and (5) the entity's credit-adjusted risk free rate.

SCE sees three other flaws in TURN's proposal. First, TURN seeks to eliminate the use of nominal cost for only a single component of depreciation – future removal costs. TURN makes no attempt to apply a consistent approach by restating plant, accumulated depreciation, and deferred taxes at current value.

Second, TURN admits that the SFAS 143 calculation is complicated and requires "substantial judgment in the determination of inflation and discount rates."[242] Finally, SP U-4 distinguishes between the "value concept" and the "cost concept." The first is related to market value, while the latter refers to nominal accounting costs. SP U-4 rejected the value concept for ratemaking purposes.[243] SCE states that SFAS 143 uses a value concept that was rejected by SP U-4.

(B) Discussion

We decline to adopt TURN's proposal to order PG&E to submit in its next GRC a study showing the net present value of removal costs for all assets using the method set forth in SFAS 143 and FIN 47. We agree with PG&E and SCE that such a study would be complex and controversial. Unless there is a clear need for such a study, we should not require it.

We are not persuaded that there is a need. PG&E has provided persuasive evidence that SP U-4 understates future removal costs in nominal dollars.[244] Thus, even though there is no explicit discounting of future removal costs under SP U-4 for the purpose of determining present value, there is an implicit discounting due to the understatement of future removal costs by SP U-4. TURN has not demonstrated that SFAS 143 and FIN 47 would provide results that are materially different from SP U-4.

Our resolution of this matter is consistent with our decision in the recent SCE GRC proceeding. There, we required SCE to provide additional information in its next GRC proceeding to justify the future removal costs determined in

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[242] Exhibit TURN-3, pp. 48, 51.

[243] SP U-4, p. 5.

[244] See summary of evidence in the Settlement Motion at pp. 260-262.

accordance with SP U-4, but we did not require SCE to provide a net present value study of all future removal costs.

If TURN wishes to pursue this matter in the next GRC, we suggest that it consider a narrowly tailored, incremental approach based on GAAP. To this end, TURN may wish to present a side-by-side comparison of (1) removal costs for AROs determined in accordance with GAAP, and (2) removal costs for the same assets determined in accordance with SP U-4. PG&E shall provide to TURN, upon request, the information that TURN may need to make this comparison. Once we have the side-by-side comparison, we will be in a better position to make an informed decision on whether to adopt for regulatory purposes a GAAP-based, net-present-value approach for those removal costs that are classified as AROs under GAAP.

9. Taxes

a. Summary

PG&E presented testimony and forecasts on income taxes, property taxes, and other taxes that PG&E must pay in 2007. The Settling Parties agreed to PG&E's methods for computing taxes.

DRA agreed with PG&E's method for estimating income taxes. In reaching its conclusion, DRA reviewed several items, including recent Federal and State tax law changes; the Federal and State tax deductions for depreciation; Federal and State operating expense adjustments; Federal and State cost-of-removal deductions; Federal and State repair allowance; Federal deduction for State Franchise Taxes; and potential charitable contribution deductions.

TURN raised two concerns about PG&E's computation of income tax expense. First, TURN recommended that if the Commission decides to disallow meal and entertainment expenses, it must also remove the related tax deduction for the disallowed expenses. PG&E agreed with TURN's proposal, which is reflected in the Comparison Exhibit and the Settlement Agreement revenue requirement. Second, TURN objected to PG&E's treatment of the income tax deduction for dividends paid on PG&E Corporation stock held in the Employee Stock Ownership Plan (ESOP), arguing that the benefit of the deduction should be flowed through to ratepayers. This matter is addressed below.

For property taxes, DRA found the results of PG&E's methodology (as set forth in its Application) reasonable and stated that the differences between DRA's property tax estimate and PG&E's were due to different plant estimates.

Finally, PG&E's forecasts for all other taxes was uncontested, including payroll, business license, federal highway use, and timber yield taxes. DRA, the only party to address these taxes, found that PG&E's method for forecasting these taxes was reasonable.

b. Discussion

PG&E and DRA provided dozens of pages of testimony and work papers regarding the various types of taxes paid by PG&E and the proper method for calculating the different taxes. The record indicates that PG&E and the Settlement Agreement have determined the various taxes in conformance with Commission precedent and all applicable tax laws and regulations.

With the exception of the ESOP, addressed below, we find that the tax amounts adopted by the Settlement Agreement are reasonable in light of the whole record, consistent with applicable law, and in the public interest.

c. Tax Deduction for ESOP Dividends

PG&E's parent company, PG&E Corporation, has an ESOP. Utility employees may invest their money in the ESOP, and the Utility (PG&E) will match 75% of employee contributions up to 6% of their salary. The cost of the

Utility's matching contributions is included in rates. Although PG&E Corp. operates the ESOP, 99.527% of the money in the ESOP relates to contributions from Utility employees and the Utility's matching contributions.

The dividends paid by PG&E Corp. to stock held by the ESOP are tax deductible. The total dividends paid to the ESOP in 2005 was $30.043 million.

TURN recommends that the tax deduction for dividends paid to the ESOP be flowed through to ratepayers. DRA did not address this issue. PG&E opposes this adjustment. The determination of who should benefit from the tax deduction (ratepayers or shareholders) does not have any consequences for PG&E employees or the benefits they will receive under the ESOP program.

i. Position of the Parties

(A) TURN

TURN estimates that the total dividends paid to the ESOP in 2007 will be $43.9 million. The RO model used by Settling Parties to calculate PG&E's revenue requirement shows that a tax deduction of $43.9 million reduces PG&E's GRC revenue requirement by $29.547 million.

TURN argues that PG&E's shareholders do not provide the funds that generate the tax deduction and, therefore, do not have an equitable right to the deduction. Rather, the deduction exists because PG&E Corp. has an ESOP that is funded largely by ratepayers (i.e., ratepayers paid the wages that fund the workers' contributions to the ESOP and PG&E's matching contributions).

TURN contends that in SCE's recent GRC proceeding the Commission held that the tax benefit belongs to ratepayers. Specifically, in A.04-12-014, SCE assigned to ratepayers the tax deduction for dividends paid to its ESOP. SCE also agreed that this ratemaking treatment was consistent with Commission precedent.[245] The Commission adopted this ratemaking treatment in D.06-05-016. TURN states that the Commission should not adopt divergent treatment for ESOP dividends in two proceedings presenting identical facts.

(B) PG&E and the Other Settling Parties

PG&E responds that the Commission held in D.84-05-036 that tax deductions attributable to management's use of retained earnings belong to shareholders, not ratepayers.[246] Since dividends are paid out of retained earnings at the discretion of management, it follows that the tax deduction attributable to these dividends properly belongs to the shareholders.

PG&E explains that after the ratepayers fund employee wages, the employees may invest their pre-tax wages in the Savings Fund Plan, which includes the ESOP. The associated tax benefit is retained by the employees. Ratepayers also fund the Utility's matching contribution, and the tax benefit of the Utility's contribution is flowed through to the ratepayers. PG&E argues that just as the ratepayers cannot claim the tax benefit realized by employees when they contribute pre-tax wages to the Savings Fund Plan, the ratepayers cannot claim the tax deductions realized by shareholders when their retained earnings are used to pay dividends to stock held by the ESOP.

PG&E disagrees with TURN that the recent SCE GRC proceeding establishes an applicable precedent. PG&E represents that the ratemaking treatment of the tax benefit was not litigated or explicitly decided by the Commission. Instead, SCE's application assigned the tax benefit to ratepayers,

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245 Exhibit TURN-44.

246 D.84-05-036, 15 CPUC 2d 42 at 48, 49.

which was not contested. PG&E testified that SCE now agrees with PG&E that the tax deduction for dividends paid to an ESOP belongs to shareholders.

ii. Discussion

The Settling Parties represent that they considered TURN's position on ESOPs and, even though the Settlement does not adopt TURN's position, that does not mean TURN's position is not reflected in the Settlement. They state that the ultimate question is not whether any particular issue is adopted or rejected by the Settlement, but whether the Settlement as a whole is reasonable.[247] We agree. It is from this perspective that we will evaluate the Settlement outcome for ESOPs.

The Settlement provides PG&E with a revenue increase of $213 million in 2007 compared to 2006. This is $181 million less than PG&E's requested increase of $395 million. The Settlement results in PG&E receiving 53.9% of its post-hearing, pre-settlement litigation position, and provides PG&E with $600 million less than it requested in cumulative revenues for 2007, 2008, and 2009. Thus, the Settlement represents a significant compromise on PG&E's part.

The question is whether this outcome is reasonable in light of the whole record regarding the issues raised by TURN, including ESOPs. We find that it is. Previously in today's Opinion, we reviewed the record for all the issues still contested by TURN, and we find in all instances that the Settlement outcome for these issues is reasonable. In fact, we find the largest disallowances proposed by TURN other than ESOPs, such as TURN's proposed disallowance for asset removal costs, are unreasonable.

[247] Settling Parties Reply Comments filed October 5, 2006, p. 120.

With this background in mind, we find that it is unnecessary to delve deeper into the merits of TURN's proposed disallowance for ESOP tax benefits. We conclude that the Settlement Agreement, by reducing PG&E's requested revenue requirement by $181 million, represents a reasonable approximation of the likely litigation outcome of all issues raised by TURN and the other parties, including ESOPs. Accordingly, we decline to adopt TURN's proposal to modify the Settlement Agreement to reduce PG&E's revenues by an additional $29.547 million.

We disagree with TURN's argument that today's Opinion represents a departure from Commission precedent in the SCE GRC proceeding. As PG&E correctly notes, our decision (D.06-05-016) in the SCE GRC proceeding did not explicitly address the ratemaking treatment of ESOPs.

F. Revenue Requirement and Rate Base

1. Results of Operations for 2007

PG&E calculated its GRC revenue requirement and rate base using the results of operations (RO) computer model that consists of thousands of inputs and algorithms. The same RO model was used to compute the Settlement RO, the Comparison Exhibit RO, and the ROs in PG&E's and DRA's filed testimony. The differences in the RO output between the Settlement and the Comparison Exhibit result from different inputs, and not from different modeling algorithms. The Settlement includes an RO for PG&E's aggregate GRC revenue requirement and rate base in 2007, and separate ROs for Electric Distribution, Gas Distribution, and Electric Generation.

Using the RO model, the Settling Parties calculated a total 2007 GRC revenue requirement of $5.043 billion, comprised of $2.950 billion for Electric Distribution, $1.073 billion for Gas Distribution, and $1.020 billion for Electric

Generation. Subtracting forecasted other operating revenues (OORs) of $116 million leaves a net revenue requirement of $4.927 billion in 2007.

Compared to 2006, the Settlement revenue requirement of $5.043 billion represents an increase of $237 million, or 4.5%, comprised of $235 million for Electric Distribution, $30 million for Gas Distribution, and a decrease of $28 million for Electric Generation. The overall increase of $237 million is offset by an increase of $24 million in other OORs to yield the net increase in billed revenues of $213 million.

The following table compares the weighted-average rate base for 2007 that was calculated by the RO model for the Settlement with PG&E's and DRA's litigation positions:

Settlement Agreement re: 2007 Weighted Average Rate Base ($ millions)							
		Comparison Exhibit			**Variances Increase/(Decrease)**		
	2006 Authorized	**PG&E**	**DRA**	**Settlement**	**Settlement vs. 2006**	**PG&E vs. Settlement**	**DRA vs. Settlement**
	(A)	(B)	(C)	(D)	(D) - (A)	(D) - (B)	(D) - (C)
Rate Base	12,311	12,746	12,347	12,550	239	(196)	203
Source: Settlement Agreement, Appendix A, Line 36.							

The Settlement allocates the rate base to Electric Distribution, Gas Distribution, and Electric Generation.[248]

There is no dispute regarding the mechanics of the RO model used by the Settlement Agreement to calculate PG&E's revenue requirement and rate base

[248] Settlement Agreement, Appendix G, Table 1-10 (Electric Distribution), Table 2-10 (Gas Distribution), and Table 3-10 (Electric Generation).

for 2007. [249] We find that the RO model is reasonable in light of the record and consistent with Commission precedent.

2. Revenue Requirement for Attrition Years

a. Position of the Parties

i. The Settlement Agreement

An attrition rate adjustment (ARA) is an element of the Rate Case Plan that adjusts the utility's revenues in the second and third years of the typical three-year GRC cycle for the purpose of sustaining the utility's earnings at an adequate level.[250] For PG&E, the second and third attrition years are 2008 and 2009.

PG&E requested that the Commission determine attrition revenue requirement increases for 2008 and 2009 based on the following:

- Detailed forecasts of capital expenditures.
- Detailed forecasts of O&M expenses for electric generation.
- At least 14 separate indices and union contracts for labor, administrative, and O&M expenses.
- Recovery of $34.8 million in either 2009 or 2010 for a second refueling outage at Diablo Canyon in 2009.
- Miscellaneous cost changes that become final as a matter of law, such as postage rate changes, franchise fee changes, income tax rate changes, and ad valorem tax changes.
- A reduction in the calculated attrition revenue requirement increases of $41 million in 2008 and $56 million in 2009 (for

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[249] TURN found an error in the way the RO model accounted for rental savings in 2007 from the replacement of fleet rental vehicles with Company-owned vehicles. This error has been corrected in the revenue requirement adopted by today's Opinion.

[250] D.00-02-046, *mimeo.*, p. 540, COL 44.

> cumulative savings of $97 million) to reflect estimated net savings from Business Transformation efforts.

PG&E's forecasted attrition revenue requirement increases are shown in the table below. PG&E also requested authority to implement attrition adjustments through advice letter filings in October of the prior year.

DRA agreed with some, but not all, of PG&E's attrition proposal. For the most part, DRA recommended that attrition increases in 2008 and 2009 be determined based on the adopted expenses and plant balances for 2007 escalated by a limited number of factors that have been widely used in prior GRC proceedings for PG&E and other utilities.

The Settlement adopts a four-year GRC cycle that spans 2007 through 2010. The Settling Parties further agree to "fixed-amount" attrition revenue increases for the years 2008, 2009, and 2010. The following table compares the Settlement attrition increases with the litigation positions of PG&E and DRA:

Attrition Revenue Requirement Increases ($ millions)					
	PG&E	**DRA**	**Settlement**	**Settlement Increase/(Decrease) Compared to:**	
				PG&E	**DRA**
	(A)	(B)	(C)	(C) - (A)	(C) - (B)
Electric Distribution					
2008	67	52	**63**	(4)	11
2009	80	61	**63**	(4)	2
2010	**N/A**	**N/A**	**63**	**N/A**	**N/A**
Gas Distribution					
2008	25	18	**22**	(3)	4
2009	25	18	**22**	(3)	4
2010	**N/A**	**N/A**	**22**	**N/A**	**N/A**
Generation					
2008	50	30	**40**	(10)	10
2009	75	52	**75**	0	23
2010	**N/A**	**N/A**	**5**	**N/A**	**N/A**
TOTAL (after Transformation Savings)					
2008	143	100	**125**	(18)	25
2009	180	131	**160**	(20)	29
2010	**N/A**	**N/A**	**90**	**N/A**	**N/A**
Source: Settlement, Appendix E, p. 27, L: 6-9.					

The Settlement provides annual attrition increases of $125 million in 2008, 2009, and 2010, plus a one-time increase of $35 million in 2009 for a refueling outage at Diablo Canyon. The reason the attrition increase of $125 million in 2008 rises to $160 million in 2009 in the above table is to include $35 million for the Diablo Canyon refueling outage. In 2010, the attrition increase is reduced from $160 million to $125 million to remove the $35 million, and is reduced from

$125 million to $90 million to account for the fact that the $35 million refueling related increase for 2009 is already built into revenues for 2010.[251]

The total attrition revenues during 2008-2010 sum to $785 million. This is equal to the cumulative $125 million-increase-per-year attrition revenues of $750 million ($375 million + $250 million + $125 million), plus $35 million for the second Diablo Canyon refueling outage in 2009. The year-over-year increase in billed revenues for base rates is 2.5% in 2008, 3.2% in 2009, and 1.7% in 2010.[252] The Settled net additions to rate base and end-of-year plant are shown in the Settlement Agreement, Appendix G, Tables 1-7, 2-7, and 3-7.[253]

The attrition revenue increases of $125 million in 2008 and $160 million in 2009 are near the mid-points of the ranges between PG&E's and DRA's recommendations for those years. The total amounts shown in the above table for 2008 - 2010 reflect PG&E's proposed reduction in its revenue requirements of $41 million in 2008 and another $56 million in 2009 (for a total of $97 million in 2009) for PG&E's forecast of the net savings from Business Transformation.

The Settling Parties agree that PG&E's next GRC should be deferred by one year, until 2011. As a result, the Settlement provides an attrition increase of $90 million in 2010 to be implemented through an advice letter filing.[254]

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[251] If the refueling is postponed from 2009 to 2010, rates in 2009 and 2010 will be adjusted to ensure that ratepayer pay no more than $35 million in total for the refueling outage. If no refueling occurs, the $35 million will be refunded.

[252] Settlement Agreement, Appendix E, as corrected.

[253] The Settling Parties agreed that an estimated $8.1 million of projects at the Humboldt Bay Power Plant (HBPP) will be recorded in a balancing account and recouped in the next GRC, if required. The Tables in Appendix G of the Settlement Agreement omit capital expenditures at HBPP.

[254] Settlement Agreement, paras. 45-47.

ii. Aglet

Aglet agrees that PG&E should receive attrition increases in 2008 and 2009, and Aglet supports an additional attrition increase of $35 million for the refueling outage at Diablo Canyon. On the other hand, Aglet states that the Settlement's attrition increases are too generous.

Aglet contends that Settled attrition increases do not properly reflect Business Transformation savings.[255] The practical effect of the Settlement, according to Aglet, is to give PG&E an annual increase of $125 million during 2008-2010, plus an additional increase of $41 million of Transformation savings in 2008 and $56 million of savings in 2009. When Transformation savings are added, the net attrition increase is 3.4% in 2008 and 3.6% in 2009.

PG&E did not provide estimated Business Transformation savings for 2010. Aglet estimates the savings in 2010 will be at least $95 million. These savings, when added to the Settlement's attrition increase of $125 million for 2010, result in an attrition rate increase of at least 4.2% in 2010.

Aglet maintains that the Settlement attrition increases (3.4% in 2008, 3.6% in 2009, and 4.2% in 2010) are too high in light of Global Insight's forecasted increases in the Consumer Price Index (CPI) of 1.61% in 2008 and 1.48% in 2009. The 2009 increase is higher than PG&E's own forecasts of escalation rates for that year. PG&E forecasted 2009 escalation rates of 3.41% for administrative costs, 3.46% for labor, 0.95% for Electric Generation, and 1.78% for Gas Service. Aglet states that if the Commission does nothing else to revise the Settlement, it should

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[255] The purpose of PG&E's Business Transformation project is to improve the way the Company does business, with the goal of establishing PG&E as an industry leader in its business processes and customer service.

cap attrition increases, before Business Transformation savings, at PG&E's own forecasted escalation rates.

Aglet's preferred alternative is to modify the Settlement Agreement to replace the fixed-amount attrition increases (other than the fixed amount for Diablo Canyon refueling outage) with attrition increases based on forecast changes to the CPI for Urban Consumers (CPI-U). As noted above, Global Insight has forecasted CPI increases of 1.61% in 2008 and 1.48% in 2009.

Aglet believes that a CPI-based attrition mechanism fairly balances shareholder and ratepayer interests and is consistent with Commission precedent. In the most recent GRC for SCG and SDG&E, the Commission stated, "The most important issue for the [attrition] indexing method is to correctly identify the most appropriate index to reasonably adjust the post-test year revenue requirements.[256]" The Commission then approved a settlement that relied on CPI forecasts. The Commission concluded, "The CPI is a reasonable indicator of inflation for SCG and SDG&E for the post-test year period until the next GRC.[257]"

iii. PG&E and the Other Parties

PG&E responds that Aglet has not provided any valid reasons for rejecting the Settlement provisions regarding attrition.

b. Discussion

We find that the Settlement Agreement's attrition increases in 2008, 2009, and 2010 are reasonable in light of the record. PG&E provided extensive and

[256] D.05-03-023, *mimeo*., p. 14.

[257] D.05-03-023, *mimeo*., p. 73, COL 9.

generally persuasive testimony supporting attrition increases in the range of those set forth in the Settlement Agreement. Our main concern with PG&E's attrition proposal is that it used an overly complex methodology that relied on more than a dozen indices and forecasted capital expenditures for hundreds of projects. As such, PG&E's proposal was contrary to the Commission's long-standing policy that attrition adjustments should be simple and non-controversial.[258] The Settlement Agreement, by adopting a fixed-amount attrition increases, complies with the Commission's policy.

Aglet's claim that the Settlement's attrition increases are "too generous" misconstrues the role that PG&E's forecasted Transformation savings play in calculating the Settled attrition increases. Aglet treats the forecasted savings as if they are additional payments from customers, adds them to the Settled attrition increases to develop higher attrition figures, and then concludes that the Settled attrition amounts are too high. In reality, the Transformation savings are not a stealthy attrition rate increase as Aglet seems to imply. PG&E's ratepayers will not pay a penny more for attrition increases than the fixed amounts explicitly set forth in the Settlement Agreement.

We decline to adopt Aglet's recommendation to cap attrition increases, before Business Transformation savings, at PG&E's own escalation rates. As shown in the previous table, PG&E's attrition proposal (which includes its escalation rates and transformation savings) results in higher attrition increases in 2008 and 2009 than the Settlement Agreement adopted by today's Opinion. Thus, adopting Aglet's recommendation would produce larger attrition increases

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[258] See, for example, D.02-02-043, 202 Cal. PUC LEXIS 168, *9.

than the Settlement Agreement. Moreover, PG&E's escalation rates set forth in Exhibit PG&E-8, Chapter 3, are not meant to apply to major cost drivers such as rate base additions and rapidly rising health care costs. Consequently, it would be inappropriate to determine attrition increases using only PG&E's escalation rates as Aglet proposes.

Turning to Aglet's proposal to base attrition increases on the CPI, we generally agree with Aglet that a CPI-based approach is relatively easy to implement, consistent with Commission precedent, and is fair to the utility and ratepayers. However, it is unnecessary to adopt Aglet's proposal here. The fixed-amount attrition increases in the Settlement Agreement are supported by the record, easy to implement, and reasonable when compared to the CPI. Excluding costs for the Diablo Canyon refueling outage in 2009, the attrition increases under the Settlement are 2.5% in 2008, 2.5% in 2009, and 2.4% in 2010.

By comparison, the annual CPI grew at an annual average of 2.5% during 1990-2005 and the utility-specific index grew at 3.2%.[259] Aglet also provided a State of California forecast that shows the California-specific CPI increasing by 3.2% from June 2007 to June 2008 and by 3.0% from June 2008 to June 2009.[260] Thus, the percentage attrition increases in the Settlement are on par with the historic CPI, less than the utility-specific cost index over the past 15 years, and lower than the forecast for the California CPI in 2008 and 2009. This comparison evidences the reasonableness of the Settled attrition increases.

For the preceding reasons, we find the Settlement provisions on attrition are reasonable in light of the record, consistent with the law, and in the public

[259] Settlement Motion, p. 310.

[260] Aglet Comments on the Settlement Agreement, Attachment, p. 45.

interest, and provide sufficient information to enable the Commission to easily implement attrition adjustments in accordance with the terms of the Settlement.

3. Interference with Other Proceedings

a. Position of the Parties

Aglet opposes a third attrition year in 2010 because a PG&E rate case for test-year 2011 would overlap with the GRCs for SDG&E and SCG (together, Sempra). Under the current rate case plan, Sempra will file rate cases for test-years 2008 and 2011. If PG&E's next rate case is pushed to a 2011 test year, it would coincide with Sempra's GRC. Aglet contends that concurrent litigation of two major GRCs is not practical for DRA, Aglet, and TURN.

PG&E believes that Aglet's concern about concurrent GRCs is unlikely to materialize. In August 2006, SDG&E and SCG each tendered an NOI for a 2008 test-year GRC. Both companies seek a five-year attrition period running from 2009 through 2013.[261] Acceptance of their proposal would move the next GRCs for SDG&E and SCG to a 2014 test year, thereby eliminating any overlap with a 2011 test-year GRC for PG&E.

b. Discussion

Aglet asks the Commission to reject the Settlement's provision for a third attrition year in 2010 to avoid concurrent GRC proceedings for PG&E and Sempra in 2011. We find that Aglet's concern is hypothetical at this point for the reasons cited by PG&E and, therefore, does not justify denial of the Settlement's provision for a third attrition year in 2010.[262] Even if the Commission does not

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[261] SDG&E NOI, p. 8; SoCalGas NOI, p. 2.

[262] If history is a guide, the 2010 attrition increase authorized by today's Opinion is likely less that what PG&E would seek in a 2010 test-year GRC application.

adopt Sempra's proposal for a five-year GRC cycle (which would cause the next Sempra GRC to overlap with PG&E's 2011 test year GRC adopted herein), this would not be the first time the Commission has conducted two major GRC proceedings in a single year. For example, the Commission concurrently processed test-year 2003 GRCs for PG&E and SCE. The Commission has the resources to do so again.[263] With proper planning and cooperation among the major parties, we believe that intervenors should be able to handle two concurrent GRCs as well.

4. PG&E Financial Health

a. Position of the Parties

Aglet recommends that the Commission find that granting PG&E all of its test year and attrition year requests is not necessary for PG&E to maintain the financial health it requires to provide adequate utility service. Aglet's makes its recommendation in response to PG&E's testimony that granting all of its request is "critical to providing PG&E sufficient revenues to continue providing safe and reliable service to customers, while providing PG&E a reasonable opportunity to earn its rate of return.[264]"

Aglet believes the Commission should view this GRC in the context of PG&E's financial condition, which is very good. PG&E has investment grade credit ratings. In 2005, total return to shareholders exceeded 15%. During the same year, PG&E Corporation had enough cash to repurchase $2.2 billion of

[263] DRA does not share Aglet's concerns about concurrent GRC proceedings. (Settling Parties reply comments, p. 15.)

[264] Exhibit PG&E-9, p. 1-1.

common stock. The trend of PG&E's ROE is improving, reaching 10.6% in 2004 despite an increase in its equity ratio to 52%.

Aglet states that the *sine qua non* of financial health is strong cash flows, which PG&E has in spades. PG&E Corporation's common stock dividend is $1.32 per share, up 10% over 2004 levels. PG&E Corporation has set a target to grow earnings per share at an average annual rate of 7.5% through 2010. Standard & Poor's expects PG&E "to produce financial results that provide a cushion sufficient to support sound credit quality.[265]"

Aglet agrees with Standard & Poor's that PG&E has sound credit quality. Aglet reviewed PG&E projected income statements, balance sheets, cash flows, and other ratemaking information.[266] Based on its review, Aglet believes that PG&E's financial metrics will remain strong.

PG&E observes that, by necessity, it must operate within the revenues set by the Commission because it has no other source of revenue. PG&E also posits that it will remain financially healthy only if its capital expenditures are allowed into rate base and authorized revenues support the required level of investment.

b. Discussion

We agree with Aglet that PG&E is financially healthy. PG&E does not need all of the test-year and attrition year revenues it requested in A.05-12-002 to maintain the financial health that PG&E requires to provide good, safe, and reliable service. This is demonstrated by the fact that the Settlement Agreement provides less revenue to PG&E than it requested in A.05-12-002. Obviously,

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[265] Exhibit Aglet-2, p. 49.

[266] Exhibit Aglet-9C, confidential calculations by PG&E, pp. 4-5. See also Standard & Poor's credit ratio guidelines, Exhibit Aglet 5-C, pp. 3-4.

PG&E would not have settled for less revenue if it believed that doing so would harm its financial health.

5. Vacancies

a. Position of the Parties

TURN believes the Settlement Agreement reflects the unrealistic assumption that PG&E will have zero employee vacancies at all times. TURN recommends that the Commission reduce PG&E's forecasted labor expenses by $10.5 million in 2004 dollars to reflect a 1% vacancy rate.

TURN represents that PG&E did not provide the number of employees or vacancies for the 2007 test year. Nor did PG&E provide a forecast of test year labor expenses for straight time versus overtime. As a result, TURN found it impossible to evaluate whether the people that PG&E is adding to fill vacancies reduces overtime costs. To aid future analysis, TURN asks the Commission to require PG&E to provide forecasted and actual staffing levels in its next GRC.

PG&E opposes TURN's recommendation. PG&E states that TURN erroneously assumes that PG&E's forecast of labor costs was based on the number of employees available to perform the work. PG&E represents that it forecasted the amount of work that needs to be done and the cost of that work. To extent PG&E has vacant positions, PG&E intends to use overtime, temporary employees, and contractors to perform the needed work.

b. Discussion

We decline to adopt TURN's proposal to reduce PG&E's revenue requirement by $10.5 million to reflect a 1% personnel vacancy rate. The fact that PG&E has vacancies does not support an inference that PG&E will have lower labor costs than set forth in the Settlement Agreement. To the contrary, the record demonstrates that vacancies will not reduce PG&E's costs, since PG&E will backfill the vacancies with overtime, temporary help, and contractors.

For example, PG&E witness Burns testified that only 145 out of 160 budgeted positions in 2006 are staffed in the Electric Supply Administration department. However, the same witness also testified that the department was in the process of filling the vacancies, that staff was working significant overtime (without overtime pay) to fulfill workload objectives, that consultants are hired to meet short-term gaps, and that some work is not being done or being done in a less thorough manner.[267] PG&E's other witnesses provided similar responses to cross examination by TURN.[268] We do not believe it is in the public interest to overwork employees or to have needed work go undone. PG&E should be allowed to recover costs based on a reasonable forecast of the work to be done by an appropriate number of employees working a normal schedule.

We agree with TURN that PG&E should provide more information in its next GRC regarding forecasted staffing levels. Labor costs are one of PG&E's largest expenses and need to be carefully reviewed in GRC proceedings. TURN represents, however, that PG&E was unable to provide sufficient information for TURN to analyze whether filling vacancies reduces overtime costs. We appreciate TURN's efforts to review PG&E's labor costs. To aid TURN's efforts in the future, we will require PG&E to provide in its next GRC a forecast of labor costs for A&G Study departments and all other office-based departments, broken down by budgeted positions, filled positions (or vacancy rate), straight time,

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[267] 14 RT 1048-49, PG&E/Burns.

[268] See, for example, Exhibit PG&E-18, p. 1-3, L:23 to p. 1-4, L: 23; Exhibit PG&E-18, pp. 47-2 to 47-3; TR 667:25 – 668:17, PG&E/Smith; and TR 1463:9-11, PG&E/Orsaba.

paid overtime, temporary labor, and outside contractors. We decline to apply this requirement to operating departments whose work is performed in the field. As noted by PG&E in its comments on the Alternate Proposed Decision, the forecast of costs for "field departments" is driven by the work to be done and the unit cost of the work, and not by forecasts of the number of employees needed to perform the work. Consequently, PG&E does not prepare, and we do not need, forecasts of labor costs for field departments at the same level of detail as for A&G Study departments and other office-based departments.

G. General Report Items and Other Miscellaneous Matters

PG&E's testimony and the Settlement Motion included so-called General Report Items that consist of assorted matters. Several of the General Report items are addressed in other parts of today's Opinion (e.g., issues raised by Greenlining). The remaining salient General Report Items and other miscellaneous matters are addressed below.

1. Escalation Rates

PG&E proposed escalation rates for most labor and benefit costs and certain non-labor costs based on data from Global Insight. DRA concurred with PG&E's escalation rates. No other party addressed this matter.

We find PG&E's escalation rates to be reasonable. We conclude that PG&E's escalation rates, when combined with other factors driving up PG&E's costs (e.g., rate base additions and rapidly rising health care costs) support the stipulated revenue requirement increases in the Settlement Agreement.

2. Productivity

California energy utilities are required by D.86-12-095 to provide reports on historic and forecasted productivity growth. As required by D.86-12-095, PG&E's testimony included a Total Factor Productivity (TFP) analysis.

Depending on the metric, PG&E forecasted TFP in the range of 1% to 2% in 2007. DRA concurred with PG&E's TFP analysis. No other party addressed this topic.

We find that PG&E's TFP analysis complies with D.86-12-095 and the results of the analysis are reasonable and adequately supported. We conclude that PG&E's fairly low rate of TFP growth (which is typical for gas and electric utilities) lends general support to the stipulated revenue requirement increases in the Settlement Agreement.

3. Mission Substation

D.06-02-003 adopted a settlement agreement that resolves issues associated with a fire at PG&E's Mission Substation in San Francisco. The settlement requires PG&E to pay $6.5 million from shareholder funds, with $6.0 million to be used to improve safety and reliability in San Francisco, and the remaining $500,000 to be paid to the State's General Fund. The decision also requires PG&E to "provide, in its next GRC…an accounting of the…$6.5 million expenditure."

To comply with this requirement, PG&E submitted Exhibit PG&E-24 in the instant GRC proceeding. In its exhibit, PG&E represents that although not all of the transactions called required by D.06-02-003 have occurred, PG&E is (1) recording all of the $6.5 million in the below-the-line Account 426.5, and (2) creating a reserve for the entire $6.5 million. When expenditures are made for the transactions described in the settlement, the costs will be charged to the reserve and not to an above-the-line account. PG&E further represents that none of the expenditures were included in its forecasts for the 2007 GRC and none will be reflected in any future GRC.

No party raised any issues regarding this matter. Based on the foregoing, we find that PG&E has complied with the requirements of D.06-02-003.

4. MOU re: Operations Affecting Disabled Persons

Disability Rights Advocates (DIRA) raised several issues regarding the impact of PG&E's operations on people with vision and mobility disabilities. On June 27, 2006, PG&E and DIRA submitted a Memorandum of Understanding (MOU) that resolves those issues raised by DIRA that are not related to the closure of front counters.[269] The MOU is contained in Attachment A of today's Opinion. The Settlement Agreement incorporates the MOU, including the additional costs and capital expenditures set forth in the MOU. There is no opposition to the MOU.

The MOU specifies the steps that PG&E will take to ensure that its local offices and pay stations are accessible to persons with mobility and vision disabilities (referred to hereafter as "disabled persons"). PG&E agrees that, with limited exceptions defined in the MOU, its entire network of authorized pay centers will be accessible to disabled persons.

The MOU also provides that PG&E will work with DIRA to complete new protocols to ensure access and safety around its construction projects in the pedestrian right of way for disabled persons. PG&E will retain a consultant to help PG&E implement the new protocols and to review compliance with the protocols during the first year of implementation.

PG&E does not know how many of its utility poles might impede the path of travel for disabled persons. The MOU provides that during 2007, PG&E's contractors who inspect utility poles in certain metropolitan areas as part of the pole test & treat program will measure the clearance between the pole and the edge of the sidewalk where it appears, based on a visual inspection, the pole may

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[269] The MOU is contained in Exhibit PG&E-71.

impede access on the sidewalk. PG&E and DIRA agree to meet and confer on data collected during 2007 to discuss whether further Commission proceedings or other actions are needed to address any barriers noted in the survey.

The MOU increases PG&E's forecast of expenses and capital expenditures for 2007 as set forth in the following table:

Activity	2007 Expense Increase	2007 Capital Increase
New protocols for temporary construction	$1,900,000	1,400,000
Survey of utility poles	$142,000	N/A
TOTAL	**$2,042,000**	**$1,400,000**

Of the $2.042 million for increased expenses, $1.862 million is for one-time costs in 2007 and $0.180 million is for recurring costs in 2007, 2008 and 2009. The amounts shown in the above table are subsumed in the Settlement outcome for GRC revenues and rate base.

a. Discussion

We find the MOU is reasonable in light of the record and in the pubic interest because it requires PG&E, at a nominal cost to ratepayers, to (1) maintain and improve access to its local offices and pay stations by disabled persons; (2) enhance safe passage around PG&E's construction sites by disabled persons; and (3) determine the extent utility poles impede access to sidewalks and public rights of way by disabled persons. The MOU is consistent with the law because it promotes compliance with federal and state laws that protect the rights of people with disabilities to full and equal access to governmental programs, services and activities, and places of public accommodation.[270] As required by Commission precedent, there is sufficient information in the MOU to enable the Commission to implement and enforce the terms of the MOU.

5. Performance Incentive Mechanism

PG&E proposed a performance incentive mechanism (PIM) whereby PG&E would receive financial rewards and penalties based on various measures of service quality. The Assigned Commissioner's Ruling and Scoping Memo dated February 3, 2006, deferred PIM issues to Phase 2 of this proceeding.

The Settling Parties agree that PG&E will withdraw its PIM proposal and that no further action should be taken on PIM. There is no opposition to the Settlement outcome for this matter. We concur with this outcome.

VI. Approval of the Settlement

Rule 12.1 requires every settlement, whether contested or not, to be reasonable in light of the whole record, consistent with the law, and in the public interest. Contested settlements are subject to additional scrutiny to ensure that the contested elements of the settlement fairly balance the interests at stake, are consistent with Commission policy objectives, and comply with Rule 12.1.

A. Reasonable in Light of the Whole Record

In today's Opinion, *supra*, we have reviewed the evidentiary record regarding (1) every element of PG&E's requested revenue requirement for 2007 through 2010, and (2) every issue raised by PG&E, DRA, Aglet, ANR/SC, TURN,

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[270] These laws include Cal. Gov. Code §§ 4450, and 11135 *et seq.*, Cal. Civ. Code §§ 51 *et seq.*, and 54 *et seq.*; the ADA, 42 U.S.C. § 12101 *et seq.*, and Section 504 of the Rehabilitation Act of 1973, 29 U.S.C. § 794; and D.06-04-070, where the Commission ordered utilities to "maintain rights of way or alternative paths of travel" when working in the public rights of way. (D.06-04-070, OP 3.)

and others. Based on our exhaustive review of the record, we conclude that the Settlement is reasonable in light of the whole record. We also find that the Settlement Agreement provides sufficient information to enable the Commission to implement the provisions, terms, and conditions of the Settlement.

The Settlement Agreement is supported by a lengthy, comprehensive, and detailed record. Because the Settlement was reached after the conclusion of 25 days of evidentiary hearings, the formal evidentiary record is complete and has been thoroughly tested through sworn testimony and cross-examination. The Settlement is further supported by the Settling Parties' 323-page Motion to approve the Settlement and the lengthy comments and reply comments on the Settlement Agreement, which together address every issue (with the exception of issues raised by Greenlining).

In its comments on the Alternate Proposed Decision, TURN argues that today's Opinion has applied the wrong burden of proof in deciding contested issues. TURN argues that Commission precedent requires utilities to affirmatively demonstrate the reasonableness of all aspects of their application. Today's Opinion fails this test, according to TURN, because it reviews each contested issue for the sole purpose of determining whether the Settlement as a whole is reasonable in light of the entire record, consistent with the law, and in the public interest. TURN argues that this unfairly shifts the burden of proof to intervenors because it forces them to demonstrate that the entire bundle of outcomes is unreasonable, rather then forcing PG&E to demonstrate that every element of the Settlement is reasonable.

We disagree with TURN's reading of Commission precedent. The standard of review for every settlement, contested or not, is set forth in Rule 12.1. This Rule requires the Commission to evaluate a settlement as a whole. That is exactly what we have done in today's Opinion. It is PG&E's burden to affirmatively demonstrate with clear and convincing evidence that the Settlement Agreement satisfies Rule 12.1. After reviewing the record for every contested issue, we find that PG&E has met its burden of proof with respect to the Settlement as a whole.

A major factor in determining whether a contested settlement is reasonable is the extent to which the settlement is supported by parties representing the affected interests.[271] The Settlement Agreement satisfies this requirement. DRA supports the Settlement in the interest of all public utility customers pursuant to its authority under § 309.5(a). PG&E supports the Settlement in the interest of its shareholders. CCUE supports the Settlement in the interest of PG&E's union employees. The Irrigation Districts, DIRA, WMA, CFBF, SCE, SDG&E, and SCG each support certain provisions of the Settlement in the interests of their particular constituencies. Of the 112 witnesses who submitted testimony, 106 were sponsored by the Settling Parties.

The Settlement Agreement represents a fair compromise of the Settling Parties' positions and interests. PG&E has demonstrated that much of its requested increase in billed revenues is reasonable. On the other hand, DRA and other parties have shown that not all of PG&E's request is reasonable. In light of this record, PG&E has agreed to accept approximately $634 million less than it requested in cumulative billed revenues during 2007, 2008, and 2009 (before the modifications adopted by today's Opinion).[272] PG&E's ratepayers, as

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[271] D.04-12-015, 2004 Cal. PUC LEXIS 574, *66.

[272] Settlement Agreement, Appendices A and E, show that PG&E agreed to accept revenue increases that were less than its request by $181 million in 2007, 18 million

Footnote continued on next page.

represented by DRA, have agreed to accept approximately $623 million more than recommended by DRA in cumulative revenues during 2007 – 2009.[273] Thus, the cumulative increase in revenues adopted by the Settlement for 2007-2009 is roughly half way between PG&E's and DRA's litigation positions. Although no party took a position on PG&E's revenue requirement for 2010, the Settlement's increase of $125 million for 2010 is consistent with prior years.

Compared to the immediately preceding year, the Settlement increases PG&E's GRC billed revenues by 4.51% in 2007, 2.54% in 2008, 3.17% in 2009, and 1.73% in 2010. These figures include $35 million for the Diablo Canyon refueling outage. Of course, PG&E's overall revenue requirement is much larger than its GRC revenue requirement. At one point in 2006, PG&E's total Commission-authorized revenue requirement was approximately $15.481 billion.[274] The Settlement increases PG&E's total billed revenues by 1.37% in 2007, 0.80 % in 2008, 1.01% in 2009, and 0.56% in 2010. The average annual increase in total billed revenues for the four-year period 2007-2010 under the Settlement is 0.9%.

Aglet, ANR/SC, and TURN oppose the Settlement outcome for certain issues. We have reviewed the record for every issue still contested by Aglet,

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in 2008, and $55 million in 2009. The cumulative amount during 2007 – 2009 = $634 million = (3 x $181 million) + (2 x $18 million) + $55 million. These figures exclude $35 million for the Diablo Canyon refueling outage.

[273] The Settlement Agreement, Appendices A and E, show that DRA agreed to accept revenue increases that exceeded its recommendation by $193 million in 2007 and $25 million in 2008, and was $6 million less than DRA's recommendation for 2009. The cumulative amount during 2007 – 2009 = $623 million = (3 x $193 million) + (2 x $25 million) – 6 million.

[274] Resolution E-3956, p. 2, Advice 2706-E-A, p. 9, Table 2, Line 38; Advice 2723-G, Attachment 1, p. 2.

ANR/SC, and TURN. We find the Settlement outcome for all of these issues is supported by the record.

Finally, today's Opinion adopts several accounting and reporting requirements that are beyond the scope of the Settlement Agreement. Perhaps the most significant is the requirement for PG&E to record in its regulatory books a regulatory liability for its pre-funded asset removal costs, which totaled $2.1 billion at the end of 2005. This requirement, which has no financial impact on PG&E, is in the public interest because it helps to ensure that PG&E will only use these funds for their intended purpose of paying for future asset removal costs. Conversely, it would be contrary to ratepayers' interests and Commission precedent if we did not require PG&E to record a regulatory asset.

The other requirements adopted by today's Opinion are listed below. Most of the items are not addressed explicitly by the Settlement Agreement, but are additional requirements that we deem necessary to ensure that the Settlement is reasonable in light of the record and in the public interest.

Additional Requirements Outside the Settlement

- We make it explicit that the cost of the new service guarantee that pays $100 to customers whose service is wrongly shut off will be borne by PG&E.
- PG&E shall report in its next GRC the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and provide a forecast of future OR and OFA costs based on its actual payment history.
- PG&E shall submit an application in 2011 on whether it is economically feasible and in the best interests of ratepayers to pursue the renewal of the Diablo Canyon operating licenses.
- PG&E shall track expenditures for membership dues in organizations that engage in political activities, including the organizations identified by TURN in this proceeding, and record

an appropriate proportion of these expenditures in the below-the-line Account 426.4.

- The report that on PBOP contributions that PG&E is required to submit at the end of the 2007 GRC cycle pursuant to the paragraph 32 of the Settlement Agreement shall state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.
- In its next GRC, PG&E shall provide the following reports and information:
    - Revised DA fees that reflect then-current costs and supporting workpapers.
    - A separate, cost-based NSF flat fee for each of the major customer classes and supporting work papers.
    - A report that demonstrates that (a) PG&E has reduced its reduce rate base by the actual salvage value on the existing airplane, (b) the depreciation expense for the new airplane is based on a 13-year service life.
    - A working cash calculation that reflects a lag for PG&E's matching savings-fund contributions in a manner consistent with today's Opinion.
    - Information regarding asset removal costs that includes: (1) the then current balance of pre-funded removal costs; (2) a year-by-year projection of (a) when the then-existing balance of pre-funded removal costs will be consumed, and (b) the implicit inflation rate for asset removal costs for each future year; and (3) a five-year projection of the year-end balance of pre-funded removal costs showing for each year the gross additions to the balance, gross expenditures for removal costs, and the net change in the balance.
    - A forecast of labor costs for A&G Study departments and other office-based departments broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

- o Upon request, such information as TURN may need to prepare a side-by-side comparison of asset removal costs for AROs determined in accordance with GAAP and SP U-4.

None of the requirements listed above is a modification of the Settlement. All are reporting requirements or other requirements for the next GRC, plus an accounting change.

B. Consistent with the Law

Aglet, ANR/SC, and TURN argue that the Settlement outcome for several issues is inconsistent with Commission precedent or other applicable legal requirements. We have carefully reviewed their arguments, *supra*. Based on our review, we find that the Settlement Agreement is consistent with the law.

C. The Public Interest

We find that the Settlement Agreement, supplemented by the additional reporting and other requirements listed above, is in the public interest because it enables PG&E to provide safe and reliable service at a reasonable cost through 2010. The Settlement does so by (1) setting a GRC revenue requirement that is consistent based on historical expenses, future trends, customer and system growth, and other cost drivers that set forth in the record; and (2) providing PG&E with the financial means to make necessary capital investments in its utility infrastructure and operations.

Equally important, the Settlement resolves numerous issues affecting the public interest that were raised by the parties. These issues include PG&E's provision of billing services for mobile home park owners, access to PG&E's facilities by disabled persons, and the continued operation of PG&E's front counters. The Settlement resolves all these issues in a way that it fair to the affected interests and beneficial to the public at large.

D. Additional Issues Raised by Aglet and TURN

We previously addressed in today's Opinion the numerous issues raised by Aglet, ANR/SC, and TURN regarding the Settlement outcome on individual matters. In addition to these individual issues, Aglet and TURN argue that the Settlement Agreement is not reasonable in light of the record and is not in the public interest. We address Aglet's and TURN's arguments below.

1. Flawed Settlement Process

TURN alleges that the Settling Parties did not provide TURN and Aglet with a meaningful opportunity to participate in settlement negotiations. When TURN and Aglet were invited to join the discussions, the Settling Parties had already settled many of the issues of importance to TURN and Aglet, including issues that had been raised by TURN or Aglet, but no other party.

In our opinion, the lack of Aglet's and TURN's participation in the initial settlement negotiations was unfortunate but does not make the Settlement unreasonable. There is no requirement that all interested parties participate in preliminary discussions. If that were the case, parties might find it difficult to reach settlements, as it is often easier to reach consensus with a few parties first, and then attempt to obtain consensus from a broader array of parties.

The only requirement regarding settlement participation is set forth in Rule 12.1, which requires the settling parties to hold a settlement conference with notice and opportunity to attend provided to all parties for the purpose of discussing the settlement. The Settling Parties complied with Rule 12.1 by holding a properly noticed settlement conference on August 16, 2006.[275]

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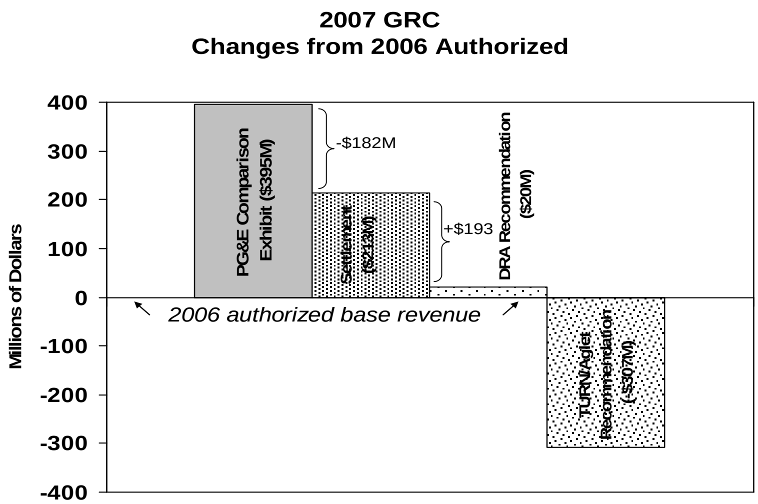
[275] After the Settlement was filed, PG&E and DRA held two technical conferences that were noticed and open to the public to answer questions regarding the Settlement.

Footnote continued on next page.

2. Overall Outcome Is Unreasonable

Aglet and TURN argue that the Settlement Agreement is unreasonable in relation to the range of dispute. The following diagram shows the litigation positions of PG&E, DRA, and TURN/Aglet compared to the Settlement:



As shown in the above diagram , the consolidated TURN/Aglet position is $327 million below DRA's position and $702 million less than PG&E's.[276]

Aglet and TURN each presented quantitative analyses that show the Settlement resolved all of their issues for pennies on the dollar. The low value accorded their issues shows that PG&E did not make any meaningful compromises on the issues they raised. Aglet and TURN believe this outcome is

PG&E also provided written responses to several questions regarding the Settlement.

[276] The $182 million figure in the diagram reflects the amount PG&E agreed to forgo as part of the Settlement, is now $181 million, due to the fact that D.06-07-027, issued in the AMI proceeding, granted PG&E approximately $887,000 in costs which were included in this proceeding pending determination of the issue in the AMI case. The $213 million figure, representing the agreed to increase in revenue requirements over 2006 authorized revenues, does not change.

inconsistent with the strength of their positions, their success in prior GRCs, and the likely result of litigation.

We disagree with Aglet's and TURN's assertion that the Settlement is unreasonable because it places a low value on the issues they raised. The relevant test is whether the outcome is reasonable in light of the whole record. We have carefully reviewed the record for every issue still contested by Aglet and TURN. We find the Settlement outcome for all of these issues is supported by the record.

In their comments on the Alternate Proposed Decision, Aglet and TURN claim that the Settlement is unreasonable because it provides PG&E with a far better outcome compared to the previous GRC. We disagree. DRA observes in its reply comments that the Settlement Agreement provides for an increase of $213 million in billed revenues for the 2007 Test Year. By contrast, the 2003 GRC increased billed revenues by $264 million. Thus, the increase provided in the 2007 Settlement Agreement is lower than the 2003 GRC on both a real and nominal dollar basis. The following table shows that the 2007 Settlement also provides PG&E with a smaller percentage increase in its test-year billed revenues compared to the 2003 GRC:

Percentage Increase (Decrease) in Authorized Billed Revenues			
	Electric Distribution	**Gas Distribution**	**Generation**
Settlement Agreement: 2007 Test Year *	8.4%	2.0%	(2.9%)
D.04-05-055: 2003 Test Year **	8.5%	4.6%	3.9%
* **Source**: Settlement Agreement, para. 14. ** **Source**: D.05-05-055, 2004 Cal. PUC LEXIS 254, *3.			

We conclude for the preceding reasons that there is no merit to Aglet's and TURN's assertion that the Settlement is unreasonable when compared to the prior GRC.

3. No Justification of Outcomes for Individual Issues

Aglet and TURN submit that the Commission must determine whether the Settlement reasonably resolves every issue raised by each party actively involved in the proceeding. Aglet and TURN contend that it is impossible to determine how the Settlement resolves most of the issues they raised. This is because several issues they raised are not addressed by the Settlement Motion or the Settlement Agreement, and the remainder of the issues raised by Aglet and TURN are subsumed in broad Settlement outcomes for expenses and rate base.

In today's Opinion, *supra*, we review the record for every issue still contested by Aglet and TURN and the Settlement outcome for each of these issues. There is ample record to do so. The Settling Parties provided a 323-page Motion that identifies almost all contested issues raised by Aglet and TURN, summarizes the record for each issue, and provides extensive citations to the evidentiary record. The evidentiary record on Aglet's and TURN's issues is voluminous. Aglet and TURN each submitted lengthy comments on the Settlement Agreement that addressed every matter still at issue, including the few issues that were omitted from the Settlement Motion. The Settling Parties' lengthy reply comments likewise addressed those issues that were omitted from the Settlement Motion.

Based on our review of the record, we conclude that the Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Affected Interests Oppose the Settlement

Aglet argues that the Settlement Agreement is unreasonable because it is opposed by residential and small commercial customers who are (1) affected by the Settlement, and (2) represented by Aglet and TURN. Aglet's point has some merit, but it does not support a finding that the Settlement is unreasonable.

Aglet and TURN can only represent their members. In contrast, DRA is authorized by § 309.5(a) to represent all of PG&E's customers, including residential and small commercial customers. While Aglet and TURN oppose the Settlement on behalf of their members, DRA supports the Settlement on behalf of all of PG&E's residential and small commercial customers. For this reason, we conclude that the Settling Parties fairly represent the interests of PG&E's residential and small commercial customers.

E. Conclusion

For all of the previous reasons, we conclude that the Settlement Agreement is reasonable in light of the whole record; fairly balances the affected interests; is consistent with applicable law, Commission precedents, and Commission policies; and is in the public interest. Therefore, we will adopt the Settlement.

In accordance with Rule 12.5, the Settlement Agreement adopted by today's Opinion is binding on all parties. Such adoption does not constitute approval of, or precedent regarding, any principle or issue.

VII. Issued Raised by the Greenlining Institute

The Greenlining Institute (Greenlining) raised a number of issues that were not addressed by the Settlement Agreement, several of which were deemed to be outside the scope of this proceeding.[277] Below, we address only those issues that fall within the scope of this proceeding.

A. Executive Compensation

Greenlining proposed several new reporting requirements regarding executive compensation. In its comments on the Alternate Proposed Decision, Greenlining agreed to drop its proposals in exchange for concessions that were made by PG&E in its comments regarding other issues raised by Greenlining. Consequently, the issues raised by Greenlining regarding executive compensation are moot and are not addressed by today's Opinion.

B. Supplier Diversity, Personnel Diversity, and Philanthropy

Greenlining made numerous recommendations regarding (1) supplier diversity; (2) the diversity of PG&E's Board of Directors, management, and certain segments of PG&E's workforce; and (3) the amount and beneficiaries of PG&E's philanthropy. PG&E opposed Greenlining's recommendations. Subsequently, Greenlining and PG&E reached an agreement on these matters, which is set forth in PG&E's and Greenlining's comments on the Alternate Proposed Decision. The Greenlining-PG&E accord resolves all issues raised by Greenlining. There was no opposition to the accord in the parties' reply comments on the Alternate Proposed Decision.

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[277] The issues raised by Greenlining that were deemed outside the scope of this proceeding included (i) revisions to PG&E's GO 77-L reports to show CEO compensation next to overall cash philanthropy and/or philanthropy to underserved communities; (ii) the use of nuclear power to reduce dependence on fossil fuels; and (iii) access to the California Solar Initiative program for renters, minorities, and low-income customers. (*See* Assigned Commissioner's Ruling Clarifying Scoping Memo issued on June 9, 2006.)

The Greenlining-PG&E accord is summarized below. We find the uncontested resolution of the issues raised by Greenlining to be reasonable, consistent with the law and Commission precedent, and in the public interest. Therefore, we will adopt the Greenlining-PG&E accord.

1. Greenlining-PG&E Accord re: Supplier Diversity

In the PG&E-Greenlining accord, PG&E pledges to make a good-faith effort to meet a minority-contract goal of 20% by 2010 or earlier, and to reach the aspirational goal of 27% or better by 2015. To achieve these goals, PG&E pledges to (1) factor in achievement of supplier diversity goals in performance evaluations and compensation; (2) establish a technical assistance program in 2008 for small, minority-owned business; and (3) work with minority-business associations to develop programs to assist small and very small businesses.

2. Greenlining-PG&E Accord re: Board and Management Diversity

PG&E pledges to make a good-faith effort to being a national leader in the diversity of its Board of Directors. This will include a good-faith effort to ensure that the Board includes African-Americans, Latinos, and Asian Americans. PG&E will also make a good-faith effort to set 10-year aspirational goals for management diversity. To this end, PG&E will maintain its current programs that link management evaluations, promotions, and bonuses to the success of management diversity goals.

3. Greenlining-PG&E Accord re: Philanthropy

In a period of just four years, PG&E's cash philanthropy has increased from 0.25% to 1.2% of pre-tax income, and the proportion of PG&E cash philanthropic giving to underserved communities increased from 25% to almost 70%. PG&E pledges to make a good faith effort to maintain this progress.

VIII. Implementation of Today's Opinion

Pursuant to D.06-10-033, the 2007 revenue requirement adopted by today's Opinion is effective as of January 1, 2007. PG&E may collect in rates over the remainder of 2007 the difference between (1) the 2007 revenue requirement authorized by today's Opinion, and (2) the amount actually collected in base rates since January 1, 2007, and prior to the implementation of the revenue requirement adopted herein.

Within 10 days from the effective date of today's Opinion, PG&E shall file an advice letter with revised tariff sheets to implement (1) the revenue requirements authorized by today's Opinion, and (2) all accounting procedures, fees, and charges authorized by today's Opinion that are not addressed in the other advice letters required by today's Opinion. The revised tariff sheets shall (i) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (ii) comply with GO 96-A, and (iii) apply to service rendered on or after their effective date.

IX. Assignment, Categorization, and Need for Hearing

John A. Bohn is the Assigned Commissioner and Timothy Kenney is the assigned ALJ in this proceeding.

In Resolution ALJ 176-3164, dated December 15, 2005, the Commission preliminarily categorized A.05-12-002 as a ratesetting proceeding and preliminarily determined that hearings were necessary. These preliminary determinations were affirmed by the Assigned Commissioner's Ruling and Scoping Memo dated February 3, 2006. There was no appeal of the Ruling.

X. Comments on the Alternate Proposed Decision

The Alternate Proposed Decision of the assigned Commissioner in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and

Rule 14.2. Timely comments were submitted by Aglet, DIRA, DRA, Greenlining, PG&E, SCE, and TURN. Timely reply comments were submitted by Aglet, DRA, Greenlining, PG&E, SCE, TURN, and jointly by the Merced Irrigation District and the Modesto Irrigation District. These comments and reply comments have been reflected, as appropriate, in the final decision adopted by the Commission.

Findings of Fact

1. PG&E's front counters are heavily used. There is a public need for the many types of services and information available at PG&E's front counters.

2. D.04-11-033 required PG&E to present in this GRC proceeding an analysis of the feasibility of offering bill-calculation services to mobile home park (MHP) owners with sub-metered tenants.

3. There is no opposition to the joint proposal submitted by PG&E, TURN, and WMA for PG&E to calculate the gas and electric utility bills for sub-metered tenants of MHPs. The proposal is substantially similar to SCE's MHP bill-calculation service approved by D.06-05-016.

4. The proposed MHP Bill-Calculation Services should benefit MHP owners and tenants, and should not affect PG&E's non-MHP customers in any way.

5. The Settlement Agreement requires PG&E to implement a new service quality standard that pays $100 to customers whose service is erroneously shut off, but there is no indication of who will bear the cost of the new standard.

6. Since PG&E's current DA fees were established in 1999, PG&E's costs have increased by 17% - 26%, depending on the category of cost.

7. PG&E incurs working-cash costs for bounced checks and recovers these costs through the NSF fee.

8. Compared to a flat fee, an NSF fee that varies by the size of the bounced check would be more costly for PG&E to implement and more confusing to customers.

9. The working-cash costs that PG&E incurs for bounced checks is proportional to the amount of the bounced check. Because the average amount for bounced checks varies by customer class, a uniform flat fee to recover PG&E's costs for bounced checks results in cross-subsidies among customer classes.

10. There is an insufficient record in this proceeding to determine a cost-based NSF flat fee for each customer class.

11. PG&E's requested expenses for its Economic Development program are cost effective under the RIM test.

12. PG&E requested $5.13 million in 2007 for other regulatory (OR) fees and $2.757 for FERC Other Federal Agency (OFA) fees. PG&E does not know with certainty whether, and to what extent, it will actually pay OR fees and OFA fees.

13. The current NRC operating licenses for Diablo Canyon expire in 2024 and 2025. It is prudent to know 10 years in advance of license expiration, or by 2014, whether the 2,200 MW of base load capacity provided by Diablo Canyon needs to be replaced so that replacement capacity and associated transmission capacity can be obtained in an orderly, cost effective, and timely manner.

14. PG&E's proposed Diablo Canyon license renewal feasibility will help policy makers reach a final decision by 2014 on whether to proceed with license renewal or, alternatively, begin the process of replacing the power provided by Diablo Canyon prior to the expiration of the operating licenses in 2024 and 2025.

15. AB 1632, which was enacted in 2006, requires the CEC to assess key policy and planning issues regarding the future of Diablo Canyon.

16. PG&E received $42.8 million in October 2006 from the federal government to settle PG&E's lawsuit over the DOE's failure to build a repository for radioactive waste from nuclear power plants.

17. PG&E improperly recorded above-the-line some of its Chamber of Commerce dues and certain other costs for political lobbying. These costs should have been recorded in the below-the-line Account 426.4.

18. The Settlement Agreement requires PG&E to file at the end of the 2007 GRC cycle a report on the revenue requirement associated with contributions to PG&E's VEBA trusts to fund PBOPs.

19. PG&E has higher medical benefit costs for active employees than SCE. However, PG&E's total compensation is within the range of competitiveness.

20. PG&E has a reasonable need for a replacement Company airplane.

21. The costs to lease and buy a replacement airplane are similar.

22. The Settlement Agreement adopts a lower revenue requirement for the Company airplane than would occur under TURN's proposal to (i) depreciate the replacement plane over 13 years, and (ii) record an estimated salvage value of $2 million for the current airplane.

23. PG&E's calculation of working cash improperly assumed zero lag days for the Company's matching contributions to the savings fund pool. The effect of PG&E's error was offset in the overall Settlement outcome for rate base.

24. PG&E had $2.1 billion of pre-funded asset removal costs at the end of 2005, and the balance will grow by $211 million annually through 2010.

25. D.06-05-016 required SCE to record a regulatory liability for pre-funded asset removal costs.

26. The Settlement attrition increases during 2008, 2009, and 2010 are (i) easy to implement, (ii) supported by PG&E's testimony, and (iii) consistent with

(a) the CPI, (b) utility-specific cost indices over the last 15 years, and (c) the State of California's forecast of the California-specific CPI.

27. Providing PG&E with a third attrition year in 2010 will result in a 2011 test-year GRC for PG&E, which would overlap with the currently scheduled test-year 2011 GRCs for SDG&E and SCG.

28. The Commission and DRA have sufficient resources to process simultaneous test-year 2011 GRCs for PG&E, SDG&E, and SCG.

29. PG&E is financially healthy.

30. Today's Opinion provides PG&E with sufficient revenues to maintain its financial health, to provide good, safe, and reliable utility service, and to make necessary capital investments.

31. D.06-02-003 requires PG&E to present in this GRC proceeding an accounting of the $6.5 million of payments required by the decision. PG&E did so in Exhibit PG&E-24, which shows that none of the $6.5 million will ever be charged to ratepayers.

32. The PG&E-DIRA MOU, which is contained in Appendix B of today's Opinion, resolves the issues raised by DIRA concerning the impact of PG&E's operations on disabled persons. There is no opposition to the MOU.

33. Labor costs are one of PG&E's largest expenses and need to be reviewed carefully in GRC proceedings.

34. PG&E was unable to provide sufficient information to enable TURN to analyze whether filling vacant employee positions reduces overtime costs.

35. The Settlement Agreement provides that PG&E will withdraw its performance incentive mechanism (PIM) from consideration in Phase 2 of this proceeding and that no further action should be taken on PIM in this proceeding.

36. The withdrawal of PG&E's PIM proposal leaves front-counter issues as the only remaining topic for Phase 2 of this proceeding.

37. The Settlement Agreement is supported by a comprehensive and detailed record.

38. The Settlement Agreement provides sufficient information to enable the Commission to implement the provisions, terms, and conditions of the Settlement.

39. The Settlement Agreement is supported by parties that fairly represent the affected interests.

40. The Settlement Agreement represents a fair compromise of the Settling Parties' positions and interests.

41. Today's Opinion reviews the record for every issue still contested by Aglet, ANR/SC, and TURN, and the Settlement outcome for each of these issues.

42. The Settlement Agreement erroneously inflates rate base by $0.624 million for capital expenditures for gas meters and PG&E's revenue requirement by $0.044 million.

43. PG&E's and Greenlining's comments on the Alternate Proposed Decision resolve all issues raised by Greenlining. The accord, which is summarized in the body of today's Opinion, requires PG&E to make good faith efforts to increase supplier diversity, Board-of-Directors diversity, management diversity, philanthropy, and cash philanthropic gifts to underserved communities.

Conclusions of Law

1. PG&E should not make any significant reductions to the staffing or operations of its front counters without Commission authorization pending the Commission's consideration of front-counter issues in Phase 2 of this proceeding.

2. The MHP Bill-Calculation Services proposed by PG&E, TURN, and WMA should be adopted because the proposal complies with D.04-11-033, is reasonable in light of record, complies with applicable law, and is in the public interest.

3. The rate base in Appendix C shall be reduced by $0.624 million and the revenue requirement in Appendix C shall be reduced by $0.044 million.

4. PG&E should file an advice letter (AL) in time to begin offering the Bill-Calculation Services by June 1, 2007. The AL should contain tariffs and a services agreement for the Bill-Calculation Services that are substantially similar to the proposed tariffs and services agreement attached to Exhibit PG&E-70.

5. It is unreasonable for ratepayers as a whole to pay $100 under the new service quality standard contemplated by the Settlement every time PG&E erroneously shuts off a customer's service. Because it is PG&E's error, PG&E should bear the cost of the new service quality standard.

6. PG&E should include in its next GRC proceeding an up-to-date analysis of its DA fees and costs.

7. To eliminate cross subsidies among customer classes for bounced checks, PG&E should provide in its next GRC proceeding (i) a cost-based NSF flat fee for each of the major customer classes, and (ii) supporting work papers.

8. Section 740.4 allows for rate recovery of utility economic development expenses to the extent of ratepayer benefits.

9. In light of the uncertainty regarding the OR fees and OFA fees that PG&E will ultimately pay, it is reasonable to order PG&E to provide in its next GRC proceeding a report of OR costs and OFA costs paid over the course of this GRC cycle and a forecast of future costs based on its actual payment history.

10. It is in the public interest for PG&E to perform the Diablo Canyon license renewal feasibility study that is described in the body of today's Opinion.

11. PG&E should incorporate into its Diablo Canyon license renewal feasibility study the findings and recommendations from the CEC's assessment of Diablo Canyon conducted pursuant to AB 1632. To this end, PG&E should defer, to the extent feasible, the work on its study, and associated spending, until after the CEC issues its findings and recommendations.

12. PG&E should submit an application by June 30, 2011, on whether renewal the Diablo Canyon operating licenses is cost effective and in the best interest of PG&E's ratepayers. The application should address the matters identified in the body of today's Opinion.

13. Any unused revenue requirement tracked by the HBPP memorandum account should accrue interest at the three-month commercial paper.

14. PG&E is required to flow through to ratepayers the settlement award of $42.8 million that PG&E received from the DOE, net of costs, in accordance with the procedures applicable to PG&E's DOE Litigation Balancing Account.

15. PG&E failed to comply with long-standing Commission policy and the requirements of the Uniform System of Accounts by not recording in the below-the-line Account 426.4 all Chamber of Commerce dues and certain other expenses for political lobbying or advocacy. PG&E should comply in the future.

16. D.92-12-015 requires that all funds collected by PG&E in rates for contributions to PBOP trusts pursuant to today's Opinion must be used for that purpose or returned to ratepayers.

17. The report that PG&E is required to submit pursuant to the Settlement Agreement at the end of the 2007 GRC cycle regarding its PBOP contributions should state if any funds collected in rates for PBOP contributions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.

18. In the next GRC, PG&E should reduce rate base by the actual salvage value on the existing airplane and present an appropriate depreciation expense for the replacement airplane based on a 13-year service life.

19. In its next GRC proceeding, PG&E's calculation of working cash should reflect a lag for the Company's matching contributions to the savings fund pool.

20. PG&E should be treated the same as SCE regarding the requirement to record a regulatory liability for pre-funded asset removal costs.

21. PG&E should either use pre-funded asset removal costs (ARCs) for their intended purpose or return these funds to ratepayers.

22. For the reasons set forth in the two previous Conclusions of Law, PG&E should record, for ratemaking purposes, a regulatory liability for pre-funded asset removal costs. The only exception should be pre-funded asset removal costs that are treated by PG&E as Asset Removal Obligations (AROs) under Generally Accepted Accounting Principles (GAAP).

23. PG&E's large and growing balance of pre-funded ARCs requires careful oversight. To this end, PG&E should provide in its next GRC the information regarding ARCs specified in the body of today's Opinion.

24. PG&E should provide to TURN in the next GRC proceeding such information as TURN may reasonably need to compare (i) removal costs for AROs determined in accordance with GAAP, and (ii) removal costs for the same assets determined in accordance with SP U-4.

25. PG&E has complied with the requirements of D.06-02-003.

26. The PG&E-DIRA MOU should be adopted because, for the reasons set forth in the body of today's Opinion, the MOU is reasonable in light of the whole record, consistent with law, and in the public interest.

27. To aid TURN's efforts to analyze PG&E's labor costs, PG&E should provide in its next GRC a forecast of labor costs for A&G Study departments and other office-based departments broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

28. The Settling Parties complied with Rule 12.1 by holding a properly noticed settlement conference on August 16, 2006.

29. The lack of Aglet's and TURN's participation in the initial settlement negotiations does not make the Settlement Agreement unreasonable.

30. The Settlement Agreement is not unreasonable because it places a low value on the issues raised by Aglet and TURN. The test is whether such an outcome is reasonable in light of the whole record. The Settlement Agreement satisfies this test.

31. The Settlement Agreement is reasonable in light of the whole record, including the record for every issue contested by Aglet, ANR/SC, and TURN;

fairly balances the affected interests; is consistent with applicable law, Commission precedents, and Commission policies; and is in the public interest.

32. The motion to adopt the Settlement Agreement should be granted.

33. Except as set forth in the previous Conclusions of Law, the recommendations of Aglet, ANR/SC, TURN, and Greenlining should not be adopted for the reasons set forth in the body of today's Opinion.

34. The accord between PG&E and Greenlining regarding supplier diversity, Board of Directors diversity, management diversity, and corporate philanthropy is reasonable and in the public interest, and should be adopted.

35. Pursuant to D.06-10-033, the 2007 revenue requirement adopted by today's Opinion is effective as of January 1, 2007.

36. Unless otherwise specified herein, PG&E should file all advice letters required by today's Opinion within 30 days. The Energy Division should be authorized to approve all the advice letters filed by PG&E pursuant to today's Opinion without a Commission resolution if such advice letters comply with today's Opinion. Such advice letters should comply with GO 96-A and be subject to a finding of compliance by the Energy Division or its successor.

37. The Settlement Agreement should be corrected to fix an error that erroneously inflates (i) rate base by $0.624 million for capital expenditures for gas meters, (ii) revenue requirement by $0.044 million.

38. The following order should be effective immediately so that PG&E 's revenue requirement authorized by today's Opinion may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The Settlement Agreement contained in Appendix C of this Order is adopted.

2. Pacific Gas and Electric Company (PG&E) is authorized to recover over the remainder of 2007 the (i) revenue requirement set forth in Appendix C of this Order, less (ii) the amount collected by PG&E in base rates since January 1, 2007, and prior to the implementation of the revenue requirement authorized by this Order, plus (iii) interest on the difference between (i) and (ii), with said interest based on the rate for prime, 3-month commercial paper reported in Federal Reserve Statistical Release H-15.

3. Within 10 days from the effective date of this Order, PG&E shall file an advice letter with revised tariff sheets to implement (i) the revenue requirement authorized by this Order, and (ii) all accounting procedures, fees, and charges authorized by this Order that are not addressed in the other advice letters required by this Order. The revised tariff sheets shall (a) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (b) comply with General Order 96-A, and (c) apply to service rendered on or after their effective date.

4. PG&E is authorized to implement and recover in 2008 through 2010 the annual attrition increases set forth in paragraph 47 of the Settlement Agreement. The attrition increases may be implemented by advice letter as set forth in paragraph 46 of the Settlement Agreement.

5. PG&E shall not make significant reductions to the staffing or operations of its 84 front counters without Commission authorization pending the Commission's consideration of front-counter issues in Phase 2 of this proceeding.

6. The Memorandum of Understanding (MOU) between PG&E and Disability Rights Advocates (DIRA) in Appendix B of today's Opinion is adopted. PG&E shall comply with the MOU.

7. PG&E shall file an advice letter (AL) in time to begin offering by June 1, 2007, the mobile home park Bill-Calculation Services described in the body of this Decision and Exhibit PG&E-70. The AL shall contain tariffs and services agreement that are substantially similar to those attached to Exhibit PG&E-70.

8. PG&E shall bear the cost of the new service quality standard adopted by the Settlement which provides for a $100 payment to each customer whose service is erroneously shut off.

9. Within 30 days from the effective date of this Order, PG&E shall file a compliance advice letter to establish the one-way Humboldt Bay Power Plant (HBPP) memorandum account in accordance with paragraph 30 of the Settlement Agreement. The HBPP memorandum account shall accrue interest at the rate earned on prime, 3-month commercial paper as reported in Federal Reserve Statistical Release H-15.

10. PG&E shall incorporate into its Diablo Canyon license renewal feasibility study the findings and recommendations from the California Energy Commission's (CEC) assessment of Diablo Canyon conducted by the CEC pursuant to Assembly Bill 1632.

11. PG&E shall submit by June 30, 2011, an application on whether to renew the Diablo Canyon operating licenses. The application shall address the matters identified in the body of today's Opinion.

12. PG&E shall identify and track all expenditures for membership dues in organizations that engage in political activities, including all the organizations

identified by TURN in this proceeding, and record an appropriate proportion of these expenditures in the below-the-line Account 426.4.

13. In its next general rate case (GRC) proceeding, PG&E shall incorporate into its calculation of working cash a lag for the Company's matching contributions to the savings-fund pool. The lag for savings-fund contributions shall be determined in a manner consistent with the directions contained in the body of today's Opinion.

14. PG&E shall record, for ratemaking purposes, a regulatory liability for asset removal costs as set forth in the body of today's Opinion. The regulatory liability shall not apply to asset removal obligations (AROs) determined in accordance with generally accepted accounting principles (GAAP). Parties may address in PG&E's next GRC whether PG&E should record, for ratemaking purposes, a regulatory liability for AROs.

15. In its next GRC proceeding, PG&E shall provide to The Utility Reform Network (TURN), upon request, the information that TURN may need to compare (i) removal costs for AROs determined in accordance with GAAP, and (ii) removal costs for the same assets determined in accordance with Standard Practice U-4.

16. PG&E shall submit the following reports and information in its next GRC proceeding:

i. An up-to-date analysis, along with supporting workpapers, of its DA costs so that appropriate DA fees may be set.

ii. A separate flat fee for not-sufficient-funds for each of the major customer classes that reflects then-current costs and supporting work papers.

iii. A report that demonstrates that (a) PG&E has reduced its rate base by the actual salvage value of the existing airplane, and (b) the depreciation expense for the replacement airplane is based on a 13-year service life.

iv. The report that PG&E is required to submit pursuant to paragraph 32 of the Settlement Agreement at the end of the 2007 GRC cycle shall state if any funds collected in rates for contributions to trusts for post-retirement benefits other than pensions were not used for that purpose and, if so, identify the mechanism and timeframe for refunding the un-contributed amount to ratepayers, with interest.

v. A report of the amount of actual payments of OR fees and OFA fees over the duration of this GRC cycle and a forecast of future OR and OFA costs based on its actual payment history.

vi. A report that contains (a) the then-current balance of pre-funded asset removal costs (ARCs); (b) a year-by-year projection of (1) when the then-existing balance of pre-funded ARCs will be consumed, and (2) the implicit inflation rate for future ARCs; and (c) a five-year projection of the year-end balance of pre-funded ARCs showing for each year the gross additions to the balance, gross expenditures for ARCs, and the net change in the balance of pre-funded ARCs.

vii. A forecast of labor costs in 2011 for A&G Study departments and other office-based departments, broken down by budgeted positions, filled positions (or vacancy rate), straight time, paid overtime, temporary labor, and outside contractors.

17. All advice letters filed pursuant to this Order shall comply with General Order 96-A and shall be subject to a finding of compliance by the Energy Division or its successor. The Commission's Energy Division may approve, without a Commission resolution, all the advice letters filed pursuant to this Order if such advice letters comply with today's Opinion.

18. The motion to adopt the Settlement Agreement is granted.

19. PG&E shall comply with its accord with the Greenlining Institute regarding supplier diversity, Board-of-Directors diversity, management diversity, and corporate philanthropy.

20. Application 05-12-002 is granted and denied to the extent set forth in the previous ordering paragraphs.

21. Application 05-12-002 and Investigation 06-03-003 remain open to address issues associated with PG&E's request to close its front counters.

This Order is effective today.

Dated March 15, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

I will file a concurrence.

/s/ TIMOTHY ALAN SIMON
Commissioner

Appendix A:

List of Appearances

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(END OF APPENDIX A)

Appendix B:

PG&E-DIRA Memorandum of Understanding (MOU)

Note: The Signed Copy of the MOU is in the Formal File for this proceeding. Appendix B of today's Opinion is an electronic copy of the MOU that does not show the parties' signatures.

Memorandum Of Understanding

This Memorandum of Understanding ("MOU") is made by and between Disability Rights Advocates ("DIRA") and Pacific Gas and Electric Company ("PG&E") (collectively, the "Parties"). In this MOU, the Parties agree on a mutually acceptable outcome to certain access issues raised by DIRA as an Intervenor in the Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007 (A.05-12-002).

RECITALS

WHEREAS the *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007* (A.05-12-002), contains forecasts of costs for test year 2007;

WHEREAS DIRA has raised certain issues regarding the impact of PG&E's practices on people with Mobility Disabilities and Vision Disabilities including: (1) access to Local Offices; (2) access to Pay Stations; (3) access to Pedestrian Rights of Way around PG&E Construction Sites; and (4) whether utility poles impede access in the Pedestrian Right of Way; and

WHEREAS PG&E and DIRA desire to resolve the issues raised by DIRA without further litigation in the current proceedings.

AGREEMENT

NOW THEREFORE, in consideration of the above Recitals and for good cause, as demonstrated below, it is hereby agreed as follows:

1 Definitions

The terms specified in this Section 1, when used in this MOU and the Recitals with the initial letters capitalized, whether in the singular or the plural, shall have the meanings stated in this Section 1.

1.1 AAA: The American Arbitration Association, or any successor organization.

1.2 Applicable Law: All federal and state laws and regulations that protect the rights of people with disabilities to full and equal access to governmental programs, services and activities and/or places of public accommodation, including Cal. Gov. Code §§ 4450, and 11135 *et seq.*, Cal. Civ. Code §§ 51 *et seq.*, and 54 *et seq.*, the Americans with Disabilities Act of 1990, 42 U.S.C. § 12101 *et seq.* and its implementing regulations including the Americans with Disabilities Act Access Guidelines (“ADAAG”), and Section 504 of the Rehabilitation Act of 1973, 29 U.S.C Sec. 794, provided however, that nothing in this MOU shall require such programs, services and activities or places of public accommodation to provide such access if exempted from doing so, or otherwise not required to do so, under these federal and state laws and regulations.

1.3 Compliance Period: The Parties agree that the MOU shall become effective the day after CPUC approval and shall remain in effect until January 1, 2010.

1.4 Construction Sites: Areas in the Pedestrian Right of Way where PG&E is performing construction or repair of electric or gas service equipment. As used herein, “Construction Sites” do not include inspections of electric or gas facilities in the Pedestrian Right of Way.

1.5 CPUC: The Public Utilities Commission of the State of California.

1.6 Effective Date: The effective date of this MOU is the day after the CPUC approves this MOU.

1.7 Local Offices: Those portions of the 84 existing PG&E-operated offices open to the public for payment of PG&E bills.

1.8 Mobility Disability: With respect to an individual, any limitation of a person’s ability to move his or her body, or a portion of his or her body, that would cause the person to meet the definition set forth in 42 U.S.C. § 12102(2)(a) and/or Cal. Gov. Code § 12926(k).

1.9 Pay Stations: Businesses owned and operated by third parties that are authorized by PG&E to accept payment of PG&E bills. Pay Stations are also known as Neighborhood Payment Centers.

1.10 Parties: Disability Rights Advocates and PG&E.

1.11 Pedestrian Rights of Way: Sidewalks and other pathways used by pedestrians along public rights of way in PG&E's electric and gas service territory.

1.12 Proceeding: *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007* (A.05-12-002).

1.13 Transaction-Related Elements: This term is defined in Section 4.1 of this MOU.

1.14 Vision Disability: With respect to an individual, any limitation of a person's ability to see that would cause the person to meet the definition set forth in 42 U.S.C. § 12102(2)(a) and/or Cal. Gov. Code § 12926(k).

2 Terms

2.1 DIRA agrees that if this MOU is approved by the CPUC, DIRA will not pursue further, on its own behalf, any of the issues that it has raised in this Proceeding prior to 2008, other than disputes regarding PG&E's implementation of this MOU. DIRA further reserves the right to seek enforcement of the obligations set forth in this MOU. Nothing in this Section 2.1, however, should restrict DIRA's ability to participate in future settlement discussions or evidentiary proceedings that may take place in the Proceeding concerning Local Offices and Pay Stations. Further, nothing in this Section 2.1 is intended to restrict DIRA's ability to represent third parties or practice law concerning the issues raised in this Proceeding, as envisioned by Rule 1-500 of the Rules of Professional Conduct of the State Bar of California.

2.2 This MOU embodies the entire understanding and agreement of the Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Parties with respect to those matters.

2.3 This MOU represents agreement between the Parties to the facts and law as specified. The Parties agree that this MOU should not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

2.4 The Parties agree that this MOU is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

2.5 The Parties agree this MOU shall not be construed against any Party because that Party or its counsel or advocate drafted the provision.

2.6 This MOU may be amended or changed only by a written agreement signed by the Parties.

2.7 The Parties shall jointly request CPUC approval of the MOU and shall actively support: (1) prompt approval of the MOU and (2) PG&E's request for additional funding as provided herein.

2.8 The Parties intend the MOU to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MOU, the Parties reserve their rights to renegotiate this MOU.

2.9 Captions are included for reference only, and are not intended to affect the meaning of the contents or the scope of this MOU.

2.10 This MOU shall be governed by and construed in accordance with California law. Each provision of this MOU shall be interpreted in such a manner as to be valid and enforceable under California law, but if any provision hereof shall be or become prohibited or invalid under any applicable law, that provision shall be ineffective only the extent of such prohibition or invalidity, without thereby invalidating the remainder of that provision or any other provision hereof.

2.11 This MOU may be executed in counterparts, which taken together shall constitute an original. Facsimiles of original pages shall be binding on the Parties to the MOU. The Parties shall exchange original signed counterparts as soon as possible.

2.12 The Parties agree that, except as otherwise noted below, the CPUC retains exclusive jurisdiction to enforce the terms of this MOU and resolve any disputes regarding the Parties' performance under this MOU.

3 Local Offices

3.1 To the extent that any of PG&E's Local Offices remain open to accept payments made in person by PG&E customers, such offices will be accessible to members of the public with Vision Disabilities and Mobility Disabilities in accordance with Applicable Law.

3.2 PG&E represents that a third party accessibility expert has surveyed, or will survey, each of its currently open Local Offices regarding their accessibility and compliance with Applicable Law. Consistent with the results of such surveys, PG&E will make all improvements necessary to ensure that all open Local Offices are accessible to people with Mobility Disabilities and Vision Disabilities in accordance with Applicable Law.

3.3 PG&E will engage a third-party accessibility expert to survey the accessibility of 10% of all open Local Offices in 2007, and 20% of all open Local Offices annually in 2008 and 2009. Prior to engagement of the expert, PG&E will notify DIRA of the identity of the expert and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected expert, PG&E will select a different expert, taking DIRA's concerns into account in the selection of the different expert. If such surveys identify barriers to accessibility in violation of Applicable Law, PG&E will have a reasonable time to make those improvements that are necessary to comply with Applicable Law. PG&E will provide the results of such surveys to DIRA, along with an estimate of the time that may be required to perform any necessary improvements.

4 Pay Stations

4.1 PG&E will engage a third-party accessibility expert to survey the transaction-related elements of accessibility at its Pay Stations ("Transaction-Related Elements") that are necessary to allow customers to complete PG&E-related transactions at such Pay Stations to ensure that these elements are in compliance with Applicable Law. These Transaction-Related Elements are set forth below:

- Parking facilities for those Pay Stations that provide parking in a facility that is under the Pay Station's control;

- Pathway(s) from the parking area to the entrance of the Pay Station for those Pay Stations that control the pathway(s) from the parking area to the entrance, including ramps along the pathway(s) (if any);

- Entrance(s) to the Pay Station, including ramps to the entrance(s) (if any);

- Pathway(s) from the entrance(s) to the service counter(s) and other areas, if any, where PG&E-related transactions take place;

- Service counter(s) and other areas or equipment, if any, where PG&E-related transactions take place; and

- For those Pay Stations that are part of a franchise or that constitute a single location within a business entity that has five or more total locations, public restrooms provided by that Pay Station, if any, that are available to customers who conduct PG&E-related transactions at the Pay Station.

- PG&E will survey 10 % or more of its Pay Stations annually in 2007, 2008 and 2009 to ensure compliance with these Transaction-Related Elements. PG&E will provide the results of such surveys to DIRA.

4.2 Prior to engagement of the expert described in Section 4.1 of this MOU, PG&E will notify DIRA of the identity of the expert and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected expert, PG&E will select a different expert, taking DIRA's concerns into account in the selection of the different expert.

4.3 If the above-referenced surveys identify barriers to accessibility concerning the Transaction-Related Elements that are not in compliance with Applicable Law, the relevant Pay Station operators shall be notified that they have a reasonable time to make the necessary improvements to remove such barriers and, if they fail to do so, the Pay Station will be removed from PG&E's network of authorized Pay Stations.

4.4 Only Pay Stations that comply with Applicable Law concerning the Transaction-Related Elements will be added to PG&E's network. At least three (3) of the Pay Stations that the third party accessibility expert surveys each year will be Pay Stations that have been added to the network during the previous year.

4.5 Notwithstanding the above, should the need arise for the use of a new or existing Pay Station that does not provide accessible Transaction-Related Elements, PG&E will consult with DIRA prior to granting an exception to the above-stated policies, providing information to DIRA on the following factors: the location of the Pay Station, the number of payments it currently processes or is expected to process, the proximity of other Pay Stations that are accessible to persons with disabilities, and the Transaction-Related Elements that may not be accessible. PG&E will take these factors into consideration, as well as the feedback of DIRA, in determining whether or not to grant an exception.

4.6 PG&E agrees to create, maintain, and make reasonably available to the public (including by listing on its website) a list of Pay Stations that PG&E believes comply with Applicable Law concerning the Transaction-Related Elements. PG&E will make this list available to the public by June 30, 2007.

5 Resolution of Disputes regarding Local Offices and Pay Stations

5.1 Any controversy arising out of or relating to this MOU as it pertains to the accessibility of Local Offices or Pay Stations, shall be resolved at the request of any Party through a three-step dispute resolution process. First, the Parties will make a good-faith effort to meet and confer to attempt to resolve the dispute. Second, if the Parties cannot resolve the dispute through meet and confer, the Parties will attempt to resolve the dispute through mediation before a mutually-acceptable third-party mediator.

5.2 If mediation is unsuccessful, the Parties agree to submit the dispute to a final and binding arbitration before a randomly-selected arbitrator from the AAA panel in San Francisco, California, administered by and in accordance with the then existing Rules of Practice and Procedure of AAA. In the event of any such dispute, the parties shall be entitled to recover reasonable attorneys' fees and costs in accordance with applicable law regarding the recovery of attorneys' fees and costs.

5.3 This dispute resolution process does not apply to any dispute concerning any issue other than access by people with Mobility and Vision Disabilities to Local Offices and Pay Stations.

6 Temporary Construction Practices

6.1 PG&E agrees to prepare new protocols to ensure accessibility and safety around PG&E Construction Sites for persons with Vision Disabilities and Mobility Disabilities ("New Access Guidelines"). PG&E will include the New Access Guidelines in its Work Area Protection Guide, a copy of which is generally maintained in all PG&E crew trucks dispatched to job sites.

6.2 PG&E reserves the right to modify the New Access Guidelines to the extent such modifications are necessary to comply with law or, update its practices after determining the efficiency of the New Access Guidelines. If the New Access Guidelines are modified, PG&E will promptly provide a copy of the modified New Access Guidelines to DIRA.

6.3 PG&E agrees to conduct training of employees who will be required to comply with the New Access Guidelines. The training will inform the employees of the purpose of the New Access Guidelines and include a demonstration of the proper use of new barriers, warning signs and temporary wheelchair ramps that will be required by the New Access Guidelines. PG&E will also include the New Access Guidelines in its annual trench safety awareness training. PG&E will provide a copy of the relevant training materials to DIRA for review.

6.4 PG&E also agrees to make construction supervisors responsible for reviewing compliance with the New Access Guidelines when the supervisors visit Construction Sites. PG&E agrees to engage a disabled access consultant to assist PG&E in developing new construction protocols, training utility employees, and assisting PG&E supervisors in the field as needed regarding the use of the new equipment during the first year after this MOU is effective. Prior to engagement of the consultant, PG&E will notify DIRA of the identity of the consultant and provide DIRA a reasonable time to object. If DIRA reasonably objects to PG&E's selected consultant, PG&E will select a different consultant, taking DIRA's concerns into account in the selection of the different consultant. The consultant shall review PG&E's adherence to the New

Access Guidelines, including as appropriate its use of the new equipment contemplated by the New Access Guidelines at no fewer than ten (10) Construction Sites in each of PG&E's seven (7) geographic areas. PG&E will provide to DIRA a summary of the consultant's conclusions and recommendations regarding the use of the new equipment biannually.

6.5 The New Access Guidelines have not yet been completed. The Parties have been working, and will continue to work, together to finalize New Access Guidelines that are acceptable to both parties. The Parties anticipate that they will be able to reach agreement on New Access Guidelines by September 30, 2006.

6.6 PG&E agrees to consult with DIRA regarding its compliance with the requirements of this Section 6. PG&E reserves the right to make any modifications to its practices that PG&E deems necessary or appropriate consistent with the intent of this MOU. If the Parties are unable to reach agreement on any of these issues, the Parties will first attempt to resolve any disputes through mediation before a mutually agreeable mediator. If the Parties are unable to resolve a dispute regarding any issues addressed in Section 6 of this MOU after mediation, such dispute shall be subject to CPUC jurisdiction as provided in Section 2.13.

6.7 PG&E estimates that implementation of procedures to comply with the New Access Guidelines would cost approximately $3.3 million in test year 2007. PG&E and DIRA request that the final decision in this proceeding increase PG&E's revenue requirement for test year 2007 to comply with the New Access Guidelines in the amount of $3.3 million total ($1.4 capital/$1.9 million expense).

7 Utility Poles in Pedestrian Rights of Way

7.1 PG&E will obtain a sampling of its pole locations during 2007 to determine whether and to what extent they pose accessibility barriers for persons with Vision Disabilities or Mobility Disabilities.

7.2 During 2007, PG&E's pole test and treat contractors will measure the clearance between PG&E-owned or jointly-owned utility poles located in the Pedestrian Right of Way and the edge of a sidewalk where it appears based on a visual inspection that the distance between the pole and the edge of the sidewalk furthest from the pole may be less than 36 inches.

PG&E will keep a record of the information it collects through this survey and will provide such information to DIRA. PG&E's contractors shall not be required to measure the clearance of more than two locations on a single block where it appears that the distance between the poles and the edge of the sidewalk are uniform.

7.3 PG&E and DIRA will meet and confer in good faith regarding the data collected during 2007 to discuss whether further Commission proceedings or other actions are necessary or appropriate to address any access barriers noted in the survey.

7.4 PG&E estimates that its incremental cost estimate to conduct a survey in 2007 of approximately 42,000 utility poles in the San Francisco, San Jose and Sacramento areas is approximately $142,000. PG&E and DIRA request that the final decision in this proceeding include an additional amount of $142,000 in revenue requirements (expense) for test year 2007.

8 Intervener Status and Compensation

8.1 PG&E agrees that the issues resolved herein were properly raised by DIRA and that DIRA has made a substantial contribution to this proceeding, as defined by Rule 1803(a) of the Commission's Rules of Practice and Procedure. The Parties agree that it is reasonable and appropriate for DIRA to receive intervenor compensation for certain tasks performed to implement the MOU, to the extent directed by the Commission.

IN WITNESS WHEREOF this MOU is executed and agreed to by the following as of the date set forth below.

//

By: ______________________________________.
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By: ______________________________________.

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Dated: June 26, 2006

(END OF APPENDIX B)

Appendix C:

General Rate Case Settlement Agreement

Note: The Signed Copy of the GRC Settlement Agreement is in the Formal File for this proceeding. Appendix C of today's Opinion is an electronic copy of the MOU that does not show the parties' signatures.

SETTLEMENT AGREEMENT AMONG PACIFIC GAS AND ELECTRIC COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE MODESTO IRRIGATION DISTRICT, THE MERCED IRRIGATION DISTRICT, THE SOUTH SAN JOAQUIN IRRIGATION DISTRICT, THE WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION, THE DISABILITY RIGHTS ADVOCATES, THE CALIFORNIA FARM BUREAU FEDERATION, SOUTHERN CALIFORNIA EDISON, SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS AND ELECTRIC COMPANY, THE COALITION OF CALIFORNIA UTILITY EMPLOYEES

SETTLEMENT AGREEMENT

1. As a compromise among their respective litigation positions, and subject to the Settlement Conditions set forth in Section 3 of this Agreement, the parties to this Settlement (Settling Parties) agree on a mutually acceptable outcome to all issues in Application (A.) 05-12-002, Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2007 (2007 General Rate Case, or GRC), with the exception of issues raised by the Greenlining Institute. The Settlement is presented to the Commission pursuant to Rule 51 of the Commission's Rules of Practice and Procedure.

SETTLING PARTIES

2. The Settling Parties are as follows: the Division of Ratepayer Advocates (DRA), Pacific Gas and Electric Company (PG&E), the Modesto Irrigation District (Modesto ID), the Merced Irrigation District (Merced ID), the South San Joaquin Irrigation District (SSJID), the Western Manufactured Housing Communities Association (WMA), the Disability Rights Advocates (DIRA), the California Farm Bureau Federation (CFBF), Southern California Edison (SCE), Southern California Gas Company (SoCalGas), San

Diego Gas and Electric Company (SDG&E), and the Coalition of California Utility Employees (CCUE).

SETTLEMENT CONDITIONS

3. The Settling Parties agree to the following general conditions:

   A. This Settlement resolves all issues raised by all Parties, with the exception of issues raised by the Greenlining Institute.

   B. This Settlement and the tables presented in the Appendices embody the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.

   C. Following Rule 51.8, the Settling Parties agree that this Settlement should not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

   D. The Settling Parties agree that this Settlement is reasonable in light of the entire record, consistent with law, and in the public interest.

   E. The Settling Parties agree that no provision of this Settlement shall be construed against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.

   F. This Settlement may be amended or changed only by a written agreement signed by the Settling Parties.

   G. The Settling Parties shall jointly request Commission approval of this Settlement and shall actively support prompt approval of the Settlement.

   H. The Settling Parties intend the Settlement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement, the Settling Parties reserve their rights under Rule 51.7.

   I. This document may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

   J. This Settlement shall become effective among the Settling Parties on the date the last Party executes the Settlement as indicated below.

K. In witness whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Settlement on behalf of the Settling Parties they represent.

L. The fact that the Settling Parties set forth specific amounts for certain categories of costs is not intended to limit PG&E's management discretion to spend funds as it sees fit and consistent with its obligation to serve.

M. Merced ID joins only in the following sections of this Settlement: paragraphs 1, 2, 3, 10, 11, 19 and 50.

N. Modesto ID joins only in the following sections of this Settlement: paragraphs 1, 2 3, 10, 11, 19, 49 and 50.

O. SSJID joins only in the following sections of this Settlement: paras. 1, 2, 3, 10 and 19.

P. WMA joins only in the following sections of this Settlement: paras. 1, 2, 3, 12 and 25.

Q. DIRA joins only in the following sections of this Settlement: paras. 1, 2, 3, 13A, and 48.

R. CFBF joins only in the following sections of this Settlement: Paragraphs 1, 2, 3, 13B, and 24.

S. SCE, SDG&E and SoCalGas join only in the following sections of this Settlement: paragraphs 1, 2, 3, 13C, and 41, but solely for the purpose of supporting the use of the traditional method for computing and reflecting net salvage rates (as described in Commission Standard Practice U-4). SCE, SDG&E and So Cal Gas did not address, and express no opinion on, the actual net salvage percentage rates adopted in the Settlement.

SETTLING PARTIES LITIGATION POSITIONS

Pacific Gas and Electric Company

4. At the end of hearings, and as reflected in Exhibit PG&E-79 (Comparison Exhibit), PG&E requested the Commission to approve total CPUC jurisdictional billed

revenue requirements of $5.109 billion,[278] effective January 1, 2007. This total consisted of $2.991 billion for electric distribution, $1.062 billion for gas distribution, and $1.056 billion for electric generation. Compared to adopted revenue requirements for 2006, PG&E's request represented a total revenue increase of $394.5 million, consisting of $342.8 million for electric distribution, $35.5 million for gas distribution, and $16.3 million for electric generation.

5. PG&E's proposed revenue requirement for 2007 was based on the costs PG&E forecasted it would incur in 2007 to own, operate, and maintain its electric generating, electric distribution, gas distribution, and common and general plant, to perform the transactions necessary to procure electricity for its bundled-service electric customers and to procure gas for its core gas customers, and to provide customer services to its electric and gas customers.

6. In addition to the revenue requirement increases for 2007, PG&E requested attrition revenue requirement increases of $143 million in 2008 and of $180 million in 2009. These amounts reflect net savings from Business Transformation.

7. PG&E also sought to increase: (1) its uncollectibles factor from 0.002 to 0.002772; (2) its "restoration for non-payment" fee (gradually over the course of the rate case cycle) from $20 to $40 for reconnection during regular business hours and from $30 to $60 for reconnection during non-business hours (CARE customers would receive a 20% discount on the increased restoration for non-payment fee); and (3) its "non-sufficient funds" fee from $8.00 to $11.50.

[278] This amount and all other amounts are in nominal FERC dollars unless noted otherwise.

Division of Ratepayer Advocates

8. At the end of hearing, and as reflected in the Comparison Exhibit, DRA's proposed overall forecast test year 2007 electric and gas distribution and electric generation CPUC jurisdictional billed revenue requirements would be $2.809 billion, $1.001 billion, and $0.924 billion, respectively. Based on current authorized revenues, DRA's proposed revenue requirements would result in an increase of $160.9 million for electric distribution and decreases of $25.3 million and $115.5 million for gas distribution and electric generation, respectively.

9. DRA's recommended attrition increases, after adjustment for Business Transformation savings, would total $100 million in 2008 and $131 million in 2009. DRA also recommended an uncollectibles factor of 0.002582. DRA proposed that any increase in the "restoration for non-payment" fee be limited to 25% more than the current fees, and that CARE customers should receive a 20% discount off the increased fees. DRA took no position on PG&E's proposed increase of the "non-sufficient funds" fee.

Modesto Irrigation District, Merced Irrigation District and South San Joaquin Irrigation District

10. Modesto ID, Merced ID and SSJID (the "Irrigation Districts") asserted that customers should not fund PG&E's $2.0 million request for Customer Retention activities or the $0.3 million request for related Regulatory/Legislative activities. SSJID also recommended disallowance of $1.6 million for Economic Development activities and $0.4 million for Military Facilities Acquisition activities.

11. In addition, Merced ID and Modesto ID called for an investigation of PG&E's implementation of Schedule E-31 to determine whether abuses are occurring. Modesto ID also called for an investigation of whether PG&E has complied with the terms of the Removal of Idle Facilities Agreement.

WMA

12. The Western Manufactured Housing Communities Association (WMA) filed a counter-proposal to PG&E's proposed bill calculation services for mobile home park owners. (PG&E's original proposal would have provided a limited amount of services to mobile home park owners at no cost to participating mobile home park owners.) Under WMA's counter-proposal, which was modeled closely after the billing services developed by Southern California Edison Company, PG&E would provide a higher level of service than originally proposed, performing the actual calculations for the mobile home park owners and charging a fee for such services to participating mobile home park owners. The joint proposal developed by WMA, PG&E and The Utility Reform Network (TURN) -- submitted as Exhibit PG&E-70 -- adopts WMA's counter-proposal with certain minor modifications.

DIRA, CCFB, SCE, SDG&E, So Cal Gas, CCUE

13. The other settling parties that also participated in the case include:

A. Disability Rights Advocates (DIRA) submitted prepared testimony in the following areas: (i) access to local offices, (ii) access to third-party pay stations, (iii) access around PG&E construction projects in the pedestrian right of way; (iv) whether utility poles create barriers in the pedestrian right of way; and (v) whether PG&E's paving practices comply with applicable law. The Memorandum of Understanding (MOU) executed by DIRA and PG&E – submitted as Exhibit PG&E-71 – addresses the first four of these areas, without prejudging or compromising any further settlement negotiations with other parties concerning the local office and pay station issues. Regarding the fifth area, as part of the MOU, DIRA agrees to withdraw from the 2007 GRC its proposals regarding paving practices, as well as any other issues raised in the GRC but not addressed by the MOU. However, nothing in the MOU limits DIRA's right to seek to raise these issues in future GRC proceedings.

B. The California Farm Bureau Federation (CFBF) presented direct testimony opposing the closure of the front counters at PG&E's local offices.

C. Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and Southern California Gas (SoCalGas) Companies presented testimony on the subject of depreciation in rebuttal to the testimony of The Utility Reform Network.

D. The Coalition of California Utility Employees (CCUE) intervened in this case on behalf of its unions whose 35,000 members work at nearly all of the electric utilities in California, including approximately 13,000 working at PG&E.

SETTLEMENT TERMS

Revenue Requirement

14. The 2007 CPUC jurisdictional billed revenue requirement of $2.870 billion for electric distribution, $1.047 billion for gas distribution and $1.010 billion for generation operations for a total of $4.927 billion is reasonable. This represents increases of 8.4% and 2.0% in PG&E's electric and gas distribution revenues, and a decrease of 2.9% in generation operation revenues, for an overall increase of 4.5%, and compares to PG&E's requests (Comparison Exhibit, p.1-4) of increases in revenues of 12.9%, 3.5%, and 1.6% for electric and gas distribution and generation operations, respectively, for an overall increase of 8.4%. Appendices A and B summarize the proposed settlement revenue requirements. On a total system billed revenue basis, the revenue increase amounts to 1.4 % for 2007.

15. Forecasts of Customers and Sales: The forecasts of gas and electric customers and sales set forth in PG&E's showing (Ex.PG&E-8) will be adopted.

16. Revenues at Present Rates: The forecasts of adopted gas and electric revenues at present rates as set forth in PG&E's showing (Ex.PG&E-79, p.2-3. p.2-14, p.2-25) will be adopted. The forecasts of billed revenues at present rates as set forth in PG&E's showing (Ex.PG&E-2, Ch.14 (electric) and Ch.15 (gas)) will be adopted.

Operations & Maintenance (O&M) Expense

17. PG&E's 2007 expenses will be handled in the following manner: 2007 O&M expenses will be $488.8 million for electric distribution, $139.9 million for gas

distribution, and $450.6 million for electric generation operations, for a total of $1.079 billion. This compares to PG&E's litigation position set forth in the Comparison Exhibit of $494.2 million (p. 2-4, Line 7 and 8), $142.5 million (p. 2-15, Lines 7 and 8), and $457.0 million (p. 2-26, Lines 5 and 7) for electric and gas distribution and generation operations, respectively, for a total of $1.094 billion.

18. **Vegetation Management:** Vegetation Management expense (included in the above electric total) will be $150 million in 2007 (SAP dollars).

A. The Vegetation Management Balancing Account will remain a one-way balancing account.

B. It is difficult to forecast the costs of the California Department of Forestry and Fire Protection (CDF) required work in this rate case, however, as PG&E and CDF are in discussions regarding hazard trees and PG&E's request for a major woody stem exemption from CDF. Thus, it is unclear whether these issues will dramatically increase costs for vegetation management or will not have any impact on those costs.

C. A separate tracking account will be established in which PG&E shall record any increased inspection or removal costs PG&E incurs due to (a) new CDF rules and/or requirements that increase hazard tree inspections or removals; (b) re-interpretation by CDF of its existing rules and/or requirements that increase hazard tree inspection or removals; (c) changes in CDF enforcement approach that require PG&E to significantly increase the scope of its Vegetation Management program, either through significantly increased inspections or tree mitigation activities, or (d) new incremental work related to so-called major woody stems, including removal of the major woody stems, adding tree wire to existing lines if appropriate, or relocating power lines further away from major woody stems.

D. PG&E shall send a letter, and a copy of the new CDF requirements, enforcement action, and/or rules, to the Commission's Energy Division and to DRA within 30 days to inform parties of this occurrence.

E. If the costs in the separate tracking account exceed $5 million in any calendar year, and if PG&E's overall expenses for Vegetation Management exceed $150 million (as adjusted for attrition), PG&E shall be authorized to recover through an advice letter filing all costs appropriately recorded in this tracking account for that calendar year through the Distribution

Revenue Adjustment Mechanism (DRAM), or subsequent mechanism established by the Commission, subject to DRA audit of those costs showing compliance with the provisions above.

Customer Services Expenses

19. PG&E's distribution Customer Services 2007 expenses will be $431.1 million for electric and gas distribution. This compares to PG&E's litigation position set forth in the Comparison Exhibit (p. 2-4 and 2-15, lines 9 and 11) of $437.7 million. This reflects a "zero" allocation in expenses for the "customer retention" component of PG&E's Customer Retention and Economic Development Program. (This compares to the $2.03 million originally sought by PG&E and reflected in Ex. PG&E-5, p. 9-1, Table 9-1, L:1.)

20. **Uncollectibles:** The factor used to calculate uncollectibles expense will be set at 0.002586.

21. **Non-sufficient Funds Fee:** The non-sufficient funds (NSF) fee for returned checks will be increased from the current $8.00 to $11.50. Within 30 days from the date of a Commission decision in this matter, PG&E will make a compliance advice filing to implement this provision.

22. **Restoration for Non-payment Fee:** The fees to restore service to customers whose service has been terminated due to lack of payment will be increased from the current $20.00 for restoration during business hours and $30.00 for restoration during non-business hours to $25.00 for restoration during business hours and $37.50 for restoration during non-business hours. However, CARE customers shall be exempt from the increase and shall continue to be liable for the current fees ($20.00 and $30.00). Within 30 days from the date of a Commission decision in this matter, PG&E will make a compliance advice filing to implement this provision.

23. **New Quality Assurance Standard for Improper Shut-offs:** The Commission should adopt a new quality assurance standard under which a customer would be paid

$100.00 by PG&E if PG&E improperly disconnects gas and/or electric service to the customer. The Settling Parties also agree that the Commission should order PG&E to explain the new standard via an advice filing to be made by PG&E within 90 days of the date of the Commission's decision in this matter. Furthermore, the Settling Parties agree that, prior to PG&E's advice filing, PG&E should meet with any interested parties in order to resolve as many details concerning implementation of the new standard as practicable.

24. **Closure of Front Counters at Local Offices:** PG&E will keep its 84 front counters at local offices open pending resolution of this issue either through settlement or Commission decision. If any front counters are ultimately closed, PG&E will adjust its revenue requirement downward to reflect savings associated with such closures. The amount of such adjustment depends upon the number of front counters closed, and therefore cannot be determined at this time.

25. **Billing Services for Mobile Home Parks:** The billing services to be provided by PG&E for mobile home park owners, as jointly proposed by Western Manufactured Housing Communities Association (WMA), The Utility Reform Network (TURN) and PG&E in Exhibit PG&E-70 are reasonable and should be adopted by the Commission.

26. **Direct Access Service Fees:** Direct access service fees will remain at current levels.

Capital Additions

27. The net weighted capital additions for 2007 will be $272.5 million for the electric distribution UCCs and $98.1 million for the gas distribution UCCs and $81.9 million for generation operation UCCs, for a total of $452.5 million. The net additions for 2005, 2006, and 2007 are shown in the Appendix G, Settlement Comparison Exhibit, Plant in Service tables for electric and gas distribution and electric generation (p.1-7, 2-7, 3-7).

28. **Replacement Airplane:** The $81.9 million of capital additions for generation operation UCCs includes PG&E's $18.0 million capital request for a replacement airplane. PG&E employees (including employees, officers, and Board members of PG&E Corporation) will be prohibited from using the Company airplane for personal travel for themselves or their family. PG&E customers and contractors, including customers and contractors of PG&E Corporation, will also be prohibited from using the Company plane for personal travel for themselves or their family.

29. Currently, PG&E implements a charge back system for passenger use of the airplane, including PG&E Corporation employees. For PG&E Utility and Corporation employees, and contractors working directly for PG&E, a $400 round trip charge is currently made to the PCC or order number of the department for whom each PG&E employee or contractor works. PG&E agrees to review and update its chargeback procedures and rates, and present the results of this update to the Commission and DRA within 90 days of a final decision in this case.

30. **Humboldt Bay Power Plant Memorandum Account:** The Settlement includes revenue requirements for some specific projects which may be required for the continued operation of the existing units at Humboldt Bay Power Plant. The estimated revenue requirements for these projects are: $1.3 million in 2007, $876 thousand in 2008 and $709 thousand in 2009. These projects are listed in Appendix C. The Settling Parties further agree that PG&E will establish a memorandum account to track the difference between the authorized and actual revenue requirement associated with these projects, and, in the next GRC, will refund any over collection of revenue requirements if it is not necessary to perform these projects.

Administrative and General (A&G) Expense

31. PG&E's total utility 2007 A&G expenses will be $772.3 million ($2004). This compares to the $806.3 million ($2004) in PG&E's position in the Comparison Exhibit,

p. F-5. These amounts equate to CPUC jurisdictional A&G amounts in 2007 FERC dollars (Appendix B) of $708.7 million compared to $741.5 million, respectively.

32. **A&G Expense – Post-retirement Benefits Other than Pension (PBOP) – Medical and Life, and Long-Term Disability Trusts**: The estimate of total contributions for 2007 to the PBOPs medical and life, and LTD trusts will be $124.3 million (total company before allocation to capital and other non-GRC UCCs). This total amount will also apply to the attrition years. In compliance with Decisions 92-12-015 and 95-12-055, PG&E will file a consolidated true-up of the revenue requirements associated with the PBOPs medical, life and LTD contributions at the end of the 2007 GRC cycle.

33. **Capitalization Rates for A&G:** The capitalization rates for those A&G items that are capitalized in the following accounts are as follows:

Account 920: Performance Incentive Plan	24.10%
Account 920: Salaries	11.12%
Account 921: Office Supplies	11.59%
Account 923: Outside Services	1.40%
Account 925: Workers Compensation	32.61%
Account 925: Third Party Claims	19.10%
Account 926: Pension and Benefits	32.61%

34. **A&G Allocation to Non-GRC UCCs:** It is more efficient to litigate common costs like A&G only once, in the GRC, and then to use the results in other CPUC proceedings, rather than re-litigating these common A&G costs multiple times. A&G expenses allocated to the Unbundled Cost Categories (UCCs) adopted in this 2007 GRC should be used in determining the A&G expenses in related proceedings in 2007 and future years until PG&E's next test year GRC, if the outcome of those proceedings would otherwise require specific calculation of A&G expenses. Specifically, the UCCs and related proceedings are: Gas Transmission (Gas Accord III and subsequent PG&E

Gas Transmission and Storage proceedings) and Nuclear Decommissioning (including SAFSTOR) (the 2006 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) and subsequent NDCTP filing).

35. **Time Tracking for PG&E's Public Affairs Related Functions:** PG&E shall, within 90 days of a final decision in this case, adopt a time reporting system to track time and expenditures of those public policy and governmental affairs organizations that have a mixture of below the line activities in addition to activities for which PG&E seeks cost recovery from the CPUC. The organizations will include Governmental Relations, Area Public Affairs, Corporate Environmental and Federal Affairs, Federal Governmental Relations, and Civic Partnership and Community Initiative. If other organizations with below the line activities, in addition to activities for which PG&E seeks cost recovery from the CPUC, are formed in the future, those organizations will also use the adopted time tracking system. PG&E shall have this reporting system implemented and in place by no later than January 1, 2008.

36. **Administrative and General Expense Analysis and Forecasting**: PG&E will work with DRA and other interested parties to improve the A&G presentation for the next GRC, which will also include presenting recorded, base year, and forecast data in a consistent, comparable, and transparent manner.

37. Pension: On June 15, 2006, the Commission issued D.06-06-014 in this proceeding and A.05-12-021 adopting an uncontested settlement agreement authorizing PG&E to recover contributions to its employee pension plan, or retirement plan, during 2006-2009. (See Ex. 1-5 and Tr. 1-25.) This final decision resolves the pension contribution issue in both proceedings, closing A.05-12-021 (which addressed the pension contribution in 2006) and leaving this proceeding (which covers pension contributions in 2007-2009) open to address all remaining GRC issues. (D.06-06-014, mimeo, pp. 2 and 26.) As a result, PG&E is making retirement plan net contributions of $249.7 million in 2006 and $153.4 million each year in 2007, 2008 and 2009. (D.06-06-014,

mimeo, p. 10.) Based on actuarial estimates and an assumed annual trust investment return of 7.5%, these contributions are projected to result in a fully funded pension plan by the beginning of the next GRC cycle on January 1, 2010. (D.06-06-014, mimeo, p. 9.) No issues remain to be resolved in this GRC regarding PG&E's retirement plan for the years 2007-2009.

38. However, because this Settlement extends through the year 2010 (see paragraph 45), the question of a pension contribution for 2010 is now raised.

39. The pension contribution settlement approved in D.06-06-014 for the years 2007-2009 should be extended through the year 2010 for the purposes of this Settlement. Specifically, the Settling Parties agree to the following:

A. PG&E is required to make a total pension contribution of $176.0 million for the year 2010, which equates to a net contribution of $153.4 million for the year 2010. (*See* D.06-06-014, *mimeo*, Finding of Fact 10 on p. 21.)

B. PG&E will continue to recover the revenue requirement for the portion of the pension contribution authorized for 2010 that is allocable to PG&E's GRC lines of business. Recovery of the pension-contribution revenue requirement for non-GRC lines of business shall be authorized, as appropriate, in other proceedings and venues. (*See* D.06-06-014, mimeo, Ordering Paragraph 6 on p. 25.)

C. The advice letter required by Ordering Paragraph 7 of D.06-06-014 shall extend through the year 2010.

D. The annual report required by Ordering Paragraph 8 of D.06-06-014 shall continue through the year 2011.

Franchise Fee Factors

40. The factors used to calculate franchise fees will be 0.007603 (electric) and 0.009736 (gas).

Depreciation Expense

41. The 2007 depreciation expenses for electric and gas distribution, and electric generation will be $596.8 million, $209.4 million, and $135.4 million, respectively, for a

total of $941.6 million. The depreciation parameters resulting from DRA's position on electric, gas, and common plant depreciation (see Ex. DRA-16, p.16-2 to 16-3; Ex. DRA-16, p.16-11 to 16-12, Table 16-2) will be used, with the exceptions as shown in Appendix D.

42. **Fossil Decommissioning Refund:** PG&E will refund in adopted rates $26.812 million per year in fossil decommissioning funds from 2007 through 2010. In the next GRC, PG&E will present an estimate of its future fossil decommissioning needs and true up the fossil decommissioning reserve at that time.

Rate Base

43. Recorded 2004 plant will be used as a starting point for calculating test year 2007 rate base. Residual common plant and depreciation reserve will be allocated using the allocation method presented in Ex. PG&E-2, pp. 8-8 to 8-10. The rate base for 2007 is $12.6 billion. The weighted average Nuclear Fuel Inventory of $221.9 million will be removed from electric generation rate base. The appropriate recorded carrying costs will be collected through the Energy Resources Recovery Account (ERRA) at the short term interest rate.

Other Operating Revenues

44. CPUC-jurisdictional Other Operating Revenues will be $80.1 million for electric distribution, $26.0 million for gas distribution and $10.1 million for electric generation. (This compares to the $79.1 million electric distribution, $26.0 million for gas distribution and $9.7 million for electric generation in PG&E's position in the Comparison Exhibit, pp. 2-3, 2-14 and 2-25.) The increase for electric distribution reflects the agreement on the non-sufficient funds fee and reconnection fee rates described above.

2011 Test Year GRC

45. PG&E's next GRC will be deferred until test year 2011 and a provision will be made for an attrition adjustment for 2010.

Attrition

46. **Attrition Authorized for Implementation by Advice Letter:** The attrition relief for 2008, 2009, and 2010 will be authorized in this GRC, and will be implemented by advice letter.

47. **Attrition Mechanism:** The attrition adjustment for base revenues for 2008 will be $125 million. The attrition adjustment for 2009 will be $125 million, plus a one-time additional amount of $35 million for a second refueling outage at Diablo Canyon Power Plant anticipated in 2009, for a total of $160 million. If a second refueling is not performed in 2009, then the $35 million will be refunded in 2010. The attrition adjustment for 2010 will be $125 million, less the one-time additional amount of $35 million from 2009, for a total of $90 million. If the anticipated 2009 second refueling outage is delayed until 2010, an additional $35 million will be provided in 2010, which will be refunded in the event the refueling does not take place.

Other Settlement Items

48. **MOU between DIRA and PG&E**: The Memorandum of Understanding (MOU) between Disability Rights Advocates (DIRA) and PG&E, submitted jointly by DIRA and PG&E as Exhibit PG&E-71, is reasonable and should be approved by the Commission, provided, however, that if the upcoming rate case cycle is extended through 2010 (as provided for in paragraph 45) then DIRA and PG&E shall negotiate conforming changes to the MOU which had been designed to last only through 2009. The costs set forth in paragraphs 6.7 and 7.4 of the MOU are included in the amounts set forth in this Settlement.

49. **Removal of Idle Facilities Investigation**: Modesto ID and PG&E agree to negotiate, in good faith, possible revisions to the existing Removal of Idle Facilities Agreement, which may include a possible extension to that agreement. Accordingly, Modesto ID withdraws its request that the Commission commence an investigation into PG&E's compliance with the terms and conditions of that agreement. To the extent Modesto ID and PG&E are unable to reach agreement on revisions to the agreement, Modesto ID reserves its right to seek an investigation, or file a complaint, regarding PG&E's compliance with the terms and conditions of such agreement in a different proceeding at such time.

50. **Schedule E-31 Investigation:** In acknowledgement of the requirement in Public Utilities Code Section 454.1 that the Commission review and report on PG&E's Schedule E-31, Merced ID and Modesto ID withdraw their request in this proceeding that the Commission commence an investigation of PG&E's implementation of Schedule E-31. Merced ID and Modesto ID reserve their right to seek such an investigation, or file a complaint, in a different proceeding at a later date.

51. **AMI:** The costs and benefits associated with Advanced Metering Initiative (AMI) are to be addressed through balancing accounts that will continue until at least 2010. (D.06-07-027, pp. 46-47.) Because AMI will not be fully deployed until 2011, the Commission has directed PG&E to evaluate continuing these balancing accounts through the 2010-2012 GRC cycle and to submit testimony to that effect in PG&E's 2010 GRC. (D.06-07-027, p. 46.) The testimony will be submitted in PG&E's 2011 GRC. The only area where PG&E presented costs in both this GRC and the AMI proceeding was Information Technology (IT). PG&E removed the duplicative IT costs from its GRC request, as shown in Appendix G of the Comparison Exhibit. (Ex. PG&E-79, p.1-3, L: 13-27 and pp. G-1 to G-15.)

52. **Cost of Capital Proceedings:** Outcomes in future Cost of Capital proceedings could affect PG&E's revenue requirement. The resulting revenue requirements from these proceedings will be calculated using the adopted 2007 rate base amounts.

53. **O&M Labor Factors**: O&M labor factors will be calculated from 2004 recorded adjusted O&M labor. The factors are shown in Appendix F.

54. **Other Balancing Accounts:** PG&E may transfer the balances in the Electric and Gas Credit Facilities Fees Tracking Accounts (the ECFFTA and GCFFTA) to the electric Distribution Revenue Adjustment Mechanism (DRAM), the Utility Generation Balancing Account (UGBA), the gas Core Fixed Cost Account (CFCA) and the Noncore Customer Class Charge Account (NCA) for recovery from customers.

55. **Results of Operations Model:** PG&E will work with DRA to continue to streamline and improve the results of operations model for the next GRC.

56. **Earnings Sharing Mechanism:** PG&E will withdraw, and the Commission will not adopt, the earnings sharing mechanism set forth in Exhibit PG&E-10, Chapter 6. DRA will withdraw, and the Commission will not adopt, DRA's alternative to PG&E's earnings sharing mechanism set forth in Exhibit DRA-18.

57. **Performance Incentive Mechanism:** PG&E will withdraw, and the Commission will not adopt, the Performance Incentives set forth in Exhibit PG&E-11**.** No further proceedings on this topic will take place in this docket.

PACIFIC GAS AND ELECTRIC COMPANY

By: *<u>/s/ Patrick G. Golden</u>*
Name: <u>PATRICK G. GOLDEN</u>

Date: <u>August 18, 2006</u>

THE MODESTO IRRIGATION DISTRICT

By: *<u>/s/ Joy Warren</u>*
Name: <u>JOY WARREN</u>

Date: <u>August 16, 2006</u>

THE SOUTH SAN JOAQUIN IRRIGATION DISTRICT

By: *<u>/s/ Jeffrey K. Shields</u>*
Name: <u>JEFFREY K. SHIELDS</u>

Date: <u>August 17, 2006</u>

THE DISABILITY RIGHTS ADVOCATES

By: *<u>/s/ Roger Heller</u>*
Name: <u>ROGER HELLER</u>

Date: <u>August 16, 2006</u>

THE COALITION OF CALIFORNIA UTILITY EMPLOYEES

By: *<u>Tanya A. Gulesserian</u>*
Name: <u>TANYA A. GULESSERIAN</u>

Date: <u>August 16, 2006</u>

SOUTHERN CALIFORNIA GAS COMPANY

By: *<u>/s/ Steven D. Davis</u>*
Name: <u>STEVEN D. DAVIS</u>

Date: <u>August 16, 2006</u>

DIVISION OF RATEPAYER ADVOCATES

By: *<u>/s/ R. Mark Pocta</u>*
Name: <u>R. MARK POCTA</u>

Date: <u>August 16, 2006</u>

THE MERCED IRRIGATION DISTRICT

By: *<u>/s/ Tracy Hunckler</u>*
Name: <u>TRACY HUNCKLER</u>

Date: <u>August 17, 2006</u>

THE WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

By: *<u>/s/ Edward G. Poole</u>*
Name: <u>EDWARD G. POOLE</u>

Date: <u>August 16, 2006</u>

THE CALIFORNIA FARM BUREAU FEDERATION

By: *<u>/s/ Ronald Liebert</u>*
Name: <u>RONALD LIEBERT</u>

Date: <u>August 16, 2006</u>

SAN DIEGO GAS AND ELECTRIC COMPANY

By: *<u>/s/ Steven D. Davis</u>*
Name: <u>STEVEN D. DAVIS</u>

Date: <u>August 16, 2006</u>

SOUTHERN CALIFORNIA EDISON COMPANY

By: *<u>/s/ John P. Hughes</u>*
Name: <u>JOHN P. HUGHES</u>

Date: <u>August 16, 2006</u>

SETTLEMENT AGREEMENT APPENDICES

APPENDIX A: Results of Operations Summary (see Appendix G for Detail)

Pacific Gas and Electric Company
2007 General Rate Case - Position Summary
Results of Operations - Test Year 2007
(Thousands of Dollars)

			Comparison Exhibit (PG&E-79)			Difference from 2006 Authorized				
Line No.	Description	2006 Authorized	PG&E	DRA	Settlement	PG&E	DRA	Settlement	Reduction	Line No.
		(A)	(B)	(C)	(D)	(E) = (B) - (A)	(F) = (C) - (A)	(G) = (D) - (A)	(H) = (G) - (E)	
	REVENUE									
1	Revenue at Effective Rates	N/A	5,148,380	4,772,226	4,967,422	N/A	N/A	N/A	N/A	1
2	Less Non-General Revenue	N/A	91,378	91,287	91,378	N/A	N/A	N/A	N/A	2
3	General Rate Case Revenue	4,817,540	5,239,758	4,863,513	5,058,800	422,218	45,973	241,260	(180,958)	3
4	Less FERC Allocation	(11,486)	(16,159)	(15,205)	(15,527)	(4,673)	(3,719)	(4,041)	632	4
5	CPUC Jurisdictional Revenue	4,806,054	5,223,599	4,848,308	5,043,273	417,545	42,254	237,219	(180,326)	5
6	Less: Other Operating Revenue	(91,759)	(114,764)	(113,861)	(116,243)	(23,005)	(22,102)	(24,484)	(1,479)	6
7	Total Billed Revenue	4,714,295	5,108,835	4,734,447	4,927,030	394,540	20,152	212,735	(181,805)	7
	OPERATING EXPENSES									
8	*Energy Costs	0	0	0	0	0	0	0	0	8
9	*Other Production	380,048	451,388	400,732	445,018	71,340	20,685	64,971	(6,370)	9
10	*Storage	0	0	0	0	0	0	0	0	10
11	*Transmission	8,972	9,537	10,118	9,537	565	1,146	565	0	11
12	*Distribution	585,609	632,767	590,135	624,690	47,158	4,526	39,081	(8,077)	12
13	*Customer Accounts	418,454	422,235	413,576	415,632	3,781	(4,878)	(2,822)	(6,604)	13
14	Uncollectibles	9,623	14,432	12,477	12,998	4,809	2,854	3,375	(1,435)	14
15	*Customer Services	5,749	15,479	11,857	15,479	9,730	6,108	9,730	0	15
16	*Administrative and General	653,501	742,168	642,869	709,398	88,667	(10,632)	55,897	(32,771)	16
17	Franchise Requirements	38,339	41,735	38,778	40,345	3,396	439	2,006	(1,391)	17
18	Amortization	8,326	6,476	6,476	6,476	(1,850)	(1,850)	(1,850)	0	18
19	Wage Change Impacts	0	0	0	0	0	0	0	0	19
20	Other Price Change Impacts	0	0	0	0	0	0	0	0	20
21	*Other Adjustments	(7,457)	(696)	0	(696)	6,761	7,457	6,761	0	21
22	Subtotal Expenses	2,101,164	2,335,520	2,127,018	2,278,874	234,356	25,854	177,711	(56,646)	22
	TAXES									
23	Superfund	0	0	0	0	0	0	0	0	23
24	Property	136,795	146,364	146,062	146,337	9,569	9,267	9,542	(27)	24
25	Payroll	68,442	80,799	75,677	80,243	12,357	7,235	11,801	(556)	25
26	Business	696	830	824	829	134	128	133	(1)	26
27	Other	415	232	230	232	(183)	(185)	(183)	(0)	27
28	State Corporation Franchise	97,668	113,821	103,206	103,489	16,153	5,538	5,821	(10,332)	28
29	Federal Income	463,129	444,841	420,601	431,049	(18,288)	(42,528)	(32,080)	(13,792)	29
30	Total Taxes	767,145	786,887	746,601	762,179	19,742	(20,544)	(4,966)	(24,708)	30
31	Depreciation	838,457	1,023,966	938,741	941,582	185,509	100,284	103,125	(82,384)	31
32	Fossil Decommissioning	28,394	(26,812)	(33,994)	(26,812)	(55,206)	(62,388)	(55,206)	0	32
33	Nuclear Decommissioning	0	0	0	0	0	0	0	0	33
34	Total Operating Expenses	3,735,159	4,119,561	3,778,365	3,955,823	384,402	43,206	220,664	(163,738)	34
35	Net for Return	1,082,117	1,120,197	1,085,148	1,102,977	38,080	3,031	20,860	(17,220)	35
36	Rate Base	12,311,492	12,746,024	12,347,220	12,550,083	434,532	35,728	238,591	(195,940)	36
	RATE OF RETURN									
37	On Rate Base	8.79%	8.79%	8.79%	8.79%	0.00%	0.00%	0.00%	0.00%	37
38	On Equity	11.35%	11.35%	11.35%	11.35%	0.00%	0.00%	0.00%	0.00%	38

APPENDIX B
Summary of Increase by Electric, Gas Distribution, and Generation
(See Appendix G for Detail)

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF INCREASE OVER ESTIMATED AUTHORIZED REVENUES
(Millions of Dollars)

Line		2006 Authorized (A)	Comparison Exhibit (PG&E-79) PG&E 2007 Proposed (B)	DRA 2007 Proposed (C)	Settlement (D)	Difference from 2006 Authorized PG&E (E) = (B) - (A)	DRA (F) = (C) - (A)	Settlement (G) = (D) - (A)	PG&E Reduction (H) = (G) - (E)	Line
	Electric Distribution									
1	Operation and Maintenance	443.9	494.2	461.7	488.8	50.3	17.8	44.9	(5.4)	1
2	Customer Services	237.6	250.7	245.1	246.8	13.1	7.6	9.2	(3.9)	2
3	Administrative and General (incl Other Adj)	317.0	353.1	306.1	337.5	36.1	(10.8)	20.5	(15.6)	3
4	Payroll Taxes, Franchise & Uncollectibles	58.1	70.0	65.4	68.0	11.9	7.4	9.9	(2.0)	4
5	Return, Taxes & Depreciation	1,670.3	1,918.1	1,824.6	1,824.6	247.8	154.3	154.3	(93.5)	5
6	Subtotal	2,726.7	3,086.0	2,903.0	2,965.6	359.2	176.2	238.9	(120.4)	6
7	Less: FERC Allocation	(11.5)	(16.2)	(15.2)	(15.5)	(4.7)	(3.7)	(4.0)	0.6	7
8	Total CPUC Jurisdiction	2,715.3	3,069.8	2,887.8	2,950.1	354.5	172.5	234.8	(119.7)	8
9	Less: Other Operating Revenue	(67.3)	(79.1)	(79.0)	(80.1)	(11.8)	(11.7)	(12.8)	(1.0)	9
10	Billed Revenue	2,648.0	2,990.8	2,808.8	2,870.0	342.8	160.9	222.0	(120.8)	10
	Gas Distribution									
11	Operation and Maintenance	138.8	142.5	133.0	139.9	3.7	(5.9)	1.0	(2.7)	11
12	Customer Services	186.6	187.0	180.3	184.3	0.4	(6.3)	(2.3)	(2.7)	12
13	Administrative and General (incl Other Adj)	183.1	197.7	171.4	189.0	14.6	(11.7)	5.9	(8.7)	13
14	Payroll Taxes, Franchise & Uncollectibles	31.0	35.1	33.1	34.5	4.0	2.0	3.5	(0.6)	14
15	Return, Taxes & Depreciation	503.6	526.0	509.5	525.8	22.5	5.9	22.2	(0.3)	15
16	Subtotal	1,043.2	1,088.4	1,027.2	1,073.4	45.2	(16.0)	30.3	(15.0)	16
17	Less: Other Operating Revenue	(16.3)	(26.0)	(25.6)	(26.0)	(9.7)	(9.3)	(9.7)	-	17
18	Billed Revenue	1,026.9	1,062.4	1,001.6	1,047.4	35.5	(25.3)	20.5	(15.0)	18
	Electric Generation									
19	Operation and Maintenance	384.5	457.0	406.3	450.6	72.5	21.9	66.2	(6.4)	19
20	Customer Services	-	-	-	-	-	-	-	-	20
21	Administrative and General (incl Other Adj)	153.5	190.7	165.3	182.3	37.2	11.9	28.8	(8.4)	21
22	Payroll Taxes, Franchise & Uncollectibles	28.4	33.0	29.5	32.1	4.5	1.1	3.7	(0.8)	22
23	Return, Taxes & Depreciation	481.3	384.8	332.1	354.7	(96.5)	(149.1)	(126.5)	(30.0)	23
24	Subtotal	1,047.6	1,065.4	933.3	1,019.8	17.8	(114.3)	(27.8)	(45.6)	24
25	Less: Other Operating Revenue	(8.2)	(9.7)	(9.3)	(10.1)	(1.5)	(1.2)	(2.0)	(0.4)	25
26	Billed Revenue	1,039.4	1,055.7	924.0	1,009.6	16.3	(115.5)	(29.8)	(46.1)	26
	Total									
27	Operation and Maintenance	967.2	1,093.7	1,001.0	1,079.2	126.5	33.8	112.1	(14.4)	27
28	Customer Services	424.2	437.7	425.4	431.1	13.5	1.2	6.9	(6.6)	28
29	Administrative and General (incl Other Adj)	653.5	741.5	642.9	708.7	88.0	(10.6)	55.2	(32.8)	29
30	Payroll Taxes, Franchise & Uncollectibles	117.5	138.0	128.0	134.6	20.5	10.5	17.1	(3.4)	30
31	Return, Taxes & Depreciation	2,655.1	2,828.9	2,666.2	2,705.1	173.7	11.1	49.9	(123.8)	31
32	Subtotal	4,817.5	5,239.8	4,863.5	5,058.8	422.2	46.0	241.3	(181.0)	32
33	Less: FERC Allocation	(11.5)	(16.2)	(15.2)	(15.5)	(4.7)	(3.7)	(4.0)	0.6	33
34	Total CPUC Jurisdiction	4,806.1	5,223.6	4,848.3	5,043.3	417.5	42.3	237.2	(180.3)	34
35	Less: Other Operating Revenue	(91.8)	(114.8)	(113.9)	(116.2)	(23.0)	(22.1)	(24.5)	(1.5)	35
36	Billed Revenue	4,714.3	5,108.8	4,734.4	4,927.0	394.5	20.2	212.7	(181.8)	36

Appendix C
Humboldt Bay Power Plant Projects Subject to Memorandum Account Tracking

Pacific Gas and Electric Company
2007 General Rate Case
Humboldt Bay Power Plant Projects Subject to Memorandum Account Tracking
(Thousands of Dollars)

Line	Description	MWC	2007	2008	2009	Line
1	**Expense** - 361b Survey Studies		**1,051**	**404**	**-**	1
	Capital Expenditures					
	Description					
2	HBPP 316b Modifications of Intake Structure	12	-	221	3,416	2
3	HBPP MEPP 2 Fire Suppression System Replace	81	-	-	466	3
4	HBPP MEPP 3 Fire Suppression System Replace	81	-	-	466	4
5	U1 HBPP NOx Reduction SB 656 (PM10)	81	2,168	-	-	5
6	U2 HBPP NOx Reduction SB 656 (PM10)	81	-	-	2,245	6
7	HBPP U2 Replace FWH Control Valves	81	-	25	98	7
8	HBPP U2 Replace Super heater	81	-	127	1,078	8
9	HBPP U1 Replace FWH Control Valves	81	-	-	25	9
10	HBPP U1Purchase/Install 2.4kV Switchgear	81	-	-	74	10
11	HBPP U1 Replace Condensate Control Valve	81	-	-	25	11
12	**Total Capital Expenditures**		**2,168**	**373**	**7,893**	12
13	**Total Estimated Revenue Requirement**		**1,341**	**876**	**709**	13

Appendix D
Settlement Net Salvage Rate Changes

Pacific Gas and Electric Company
2007 General Rate Case
SETTLEMENT NET SALVAGE RATES

Line	FERC Acct	Asset Class	PG&E Proposal NS%	DRA Proposal NS%	PG&E/DRA Settlement NS%	Line
		Electric Generation Plant				
1		EHP Electric Hydro Production	-13%	-9%	-13%	1
		Electric Transmission Plant- Non Network				
2	353	ETP35301 Station Equipment	-30%	-10%	-23%	2
3	354	ETP35400 Towers and Fixtures	-50%	-40%	-46%	3
4	355	ETP35500 Poles and Fixtures	-80%	-70%	-67%	4
		Electric Distribution Plant				
5	364	EDP36400 Poles Towers and Fixtures	-100%	-85%	-80%	5
6	365	EDP36500 OH Conductor & Devices	-100%	-80%	-77%	6
7	367	EDP36700 Underground Conduct & Devices	-40%	-35%	-30%	7
		Gas Distribution Plant				
8	376	GDP37601 Mains	-50%	-45%	-50%	8
9	380	GDP38000 Services	-100%	-90%	-100%	9

Note:

The above table only includes accounts where the net salvage differs from DRA

Appendix E
Settlement Attrition Summary

APPENDIX E - Settlement Attrition Summary (Errata)
(Millions of Dollars)

Pacific Gas and Electric Company
2007 General Rate Case
Attrition Summary
(Millions of Dollars)

		2008			2009			2010
Line		PG&E	DRA	Settlement	PG&E	DRA	Settlement	Settlement
1	Attrition Revenues	184	141		236	187		
2	Transformation Net Savings*	(41)	(41)		(56)	(56)		
3	**Total Base Attrition Revenues**	**143**	**100**	**125**	**180**	**131**	**125**	**125**
4	**DCPP 2nd Refueling (one-time revenues)**			**0**			**35**	**(35)**
5	**Total Adjusted Attrition Revenues**			**125**			**160**	**90**

** Transformation Savings: For 2009, the annual savings are $97 million, which includes $41 million in savings from 2008 and an incremental $56 million in savings for 2009.*

Allocation of Settlement Attrition Revenues by Electric and Gas Distribution, Generation
(allocated based on 2007 CPUC Billed Revenue)

		2008	2009	2010
6	Electric Distribution	63	63	63
7	Gas Distribution	22	22	22
8	Electric Generation	40	75	5
9	**Total Attrition Revenues**	**125**	**160**	**90**
10	% Increase over 2007 GRC Proposed Settlement Billed Revenues	2.5%	3.2%	1.7%

Appendix F
O&M Labor Factors

Pacific Gas and Electric Company
2007 General Rate Case
O&M LABOR FACTORS BY UNBUNDLED COST CATEGORY
(Thousands of 2004 Dollars)

		Recorded Adjusted 2004		
Line	Unbundled Cost Category	$	Percentage	Line
	Electric Generation			
1	EG - Fossil Facilities (1)	10,849	1.19%	1
2	EG - Fossil Transmission (2)	178	0.02%	2
3	EG - Hydro Facilities (3)	40,660	4.47%	3
4	EG - Hydro Transmission (4)	2,429	0.27%	4
5	EG - Diablo Canyon Power Plant (5)	138,227	15.18%	5
6	EG - Diablo Canyon Transmission (6)	-	0.00%	6
7	EG - Purchased Power Payments (8)	-	0.00%	7
8	EG - Electric Supply Administration (14)	14,326	1.57%	8
9		206,669	22.70%	9
10	**Nuclear Decommissioning**			10
11	ND - Nuclear Decomm. (SAFSTOR) (7)	4,632	0.51%	11
12		4,632	0.51%	12
13	**Electric Transmission**			13
14	ET - El Trans High Voltage (9)	29,073	3.19%	14
15	ET - El Trans Low Voltage (10)	29,713	3.26%	15
16	ET - Third-Party Generation-Ties (11)	498	0.05%	16
17	ET - Partnership Generation-Ties (12)	29	0.00%	17
18		59,313	6.51%	18
19	**Electric Distribution**			19
20	ED - Wires and Services (13)	360,413	39.58%	20
21	ED - Trans. Level Direct Connects (15)	306	0.03%	21
22	ED - Electric Public Purpose Program Admin. (16) see note 1	21,916	2.41%	22
23		382,635	42.02%	23
24	**Electric Public Purpose Program**			24
25	EP - Electric Public Purpose Programs Costs (17)	-	0.00%	25
26	SPARE (18)	-	0.00%	26
27		-	0.00%	27
28				28
29	**Electric Total**	653,249	71.74%	29
30				30
31	**Gas Transmission**			31
32	GT - Gas Gathering (19)	2,694	0.30%	32
33	GT - Gas Storage (20)	5,024	0.55%	33
34	GT - Gas Local Transmission (21)	2,129	0.23%	34
35	GT -Gas Local Transmission Line 401 (22)	2,156	0.24%	35
36	GT - Gas Transmission: Backbone (23)	30,919	3.40%	36
37	GT - Gas Transmission: Customer Access Charge (24)	143	0.02%	37
38	GT - Gas Local Transmission: Line 401 Settlement Adjustment (25)	-	0.00%	38
39		43,065	4.73%	39
40	**Gas Distribution**			40
41	GD - Pipes and Services (26)	206,054	22.63%	41
42	GD - Gas Procurement Administration (27)	2,347	0.26%	42
43	GD - Gas Public Purpose Admin. (28) see note 1	5,862	0.64%	43
44		214,263	23.53%	44
45	**Gas Public Purpose Programs**			45
46	GP - Gas Public Purpose Programs Costs (29)	-	0.00%	46
47		-	0.00%	47
48				48
49	**Gas Total**	257,328	28.26%	49
50				50
51	**Company Total**	910,577	100.00%	51

Note 1 - PPP Admin costs are transferred from the program for allocation purposes and are not collected in the case

Appendix G

Settlement Comparison Exhibit – Results of Operations

This section contains tables showing summaries of proposed revenues and results of operations calculations, comparing PG&E and DRA's Comparison Exhibit positions with the Settlement.

Table 1-1
2007 General Rate Case
Revenue Summary – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUES AT PRESENT RATES					
	CPUC Revenues (Retail)					
1	Revenues from Sales	2,557,932	2,557,932	0	2,557,932	0
2	Plus: Non-Applicable Revenue	90,027	90,027	0	90,027	0
3	CPUC Revenue	2,647,959	2,647,959	0	2,647,959	0
4	Plus: Adopted Other Operating Revenue	67,300	67,300	0	67,300	0
5	Rate Case Revenue	2,715,259	2,715,259	0	2,715,259	0
	FERC Revenues (Wholesale)					
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	0	0
8	FERC Revenue	0	0	0	0	0
9	Plus: Other Operating Revenue	14,344	14,344	0	14,344	0
10	Rate Case Revenue	14,344	14,344	0	14,344	0
11	Total Rate Case Revenue	2,729,603	2,729,603	0	2,729,603	0
	INCREASE IN RATE CASE REVENUE					
12	CPUC Jurisdiction	354,546	234,814	(119,732)	172,524	62,290
13	FERC Jurisdiction	1,815	1,183	(632)	863	320
14	Total Increase	356,361	235,997	(120,364)	173,387	62,610
15	Percent	13.06%	8.65%		6.35%	
	INCREASE IN CPUC Revenue from Sales					
16	Amount	342,796	222,015	(120,780)	160,864	61,151
17	Percent	13.40%	8.68%		6.29%	
	REVENUES AT PROPOSED RATES					
	CPUC Revenues (Retail)					
18	Revenues from Sales	2,900,728	2,779,947	(120,780)	2,718,796	61,151
19	Plus: Non-Applicable Revenue	90,027	90,027	0	90,027	0
20	CPUC Revenue	2,990,755	2,869,974	(120,780)	2,808,823	61,151
21	Plus: Other Operating Revenue	79,050	80,099	1,048	78,960	1,139
22	Rate Case Revenue	3,069,805	2,950,073	(119,732)	2,887,783	62,290
	FERC Revenues (Wholesale)					
23	Revenues from Sales	1,815	1,183	(632)	863	320
24	Plus: Non-Applicable Revenue	0	0	0	0	0
25	FERC Revenue	1,815	1,183	(632)	863	320
26	Plus: Other Operating Revenue	14,344	14,344	0	14,344	0
27	Rate Case Revenue	16,159	15,527	(632)	15,207	320
28	**Total Rate Case Revenue**	3,085,964	2,965,600	(120,364)	2,902,990	62,610

Table 1-2
2007 General Rate Case
Results of Operations – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUE					
1	Revenue at Effective Rates	2,995,937	2,875,573	(120,364)	2,812,963	62,610
2	Less Non-General Revenue	90,027	90,027	0	90,027	0
3	= General Rate Case Revenue	3,085,964	2,965,600	(120,364)	2,902,990	62,610
	OPERATING EXPENSES					
4	Energy Costs	0	0	0	0	0
5	Other Production	0	0	0	0	0
6	Storage	0	0	0	0	0
7	Transmission	726	726	0	726	0
8	Distribution	493,447	488,040	(5,406)	460,970	27,070
9	Customer Accounts	247,298	243,421	(3,877)	241,763	1,658
10	Uncollectibles	8,539	7,655	(884)	7,482	173
11	Customer Services	3,373	3,373	0	3,369	4
12	Administrative & General	353,399	337,795	(15,605)	306,116	31,679
13	Franchise Requirements	23,356	22,449	(907)	21,975	474
14	Amortization	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(332)	(332)	0	0	(332)
18	Subtotal Expenses	1,129,805	1,103,127	(26,678)	1,042,401	60,726
	TAXES					
19	Superfund	0	0	0	0	0
20	Property	97,415	97,402	(13)	97,215	188
21	Payroll	37,611	37,409	(202)	35,475	1,934
22	Business	386	386	0	386	0
23	Other	108	108	0	108	0
24	State Corp. Franchise	79,233	70,978	(8,254)	72,663	(1,684)
25	Federal Income	311,480	306,024	(5,456)	303,608	2,416
26	Total Taxes	526,233	512,308	(13,925)	509,455	2,853
27	DEPRECIATION	678,883	596,774	(82,109)	608,035	(11,260)
28	Fossil Decommissioning	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	2,334,921	2,212,210	(122,712)	2,159,890	52,319
31	**NET FOR RETURN**	751,042	753,390	2,348	743,099	10,291
32	**RATE BASE**	8,545,639	8,572,359	26,720	8,455,263	117,096
	RATE OF RETURN					
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 1-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Distribution
($000)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	3,085,964	2,965,600	(120,364)	2,902,990	62,610
2	O&M Expenses	1,129,805	1,103,127	(26,678)	1,042,401	60,726
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	135,520	135,305	(215)	133,184	2,122
6	Subtotal	1,820,638	1,727,167	(93,471)	1,727,405	(238)
	DEDUCTIONS FROM TAXABLE INCOME					
7	Interest Charges	236,646	237,386	740	234,143	3,243
8	Fiscal/Calendar Adjustment	2,470	2,458	(13)	2,272	186
9	Operating Expense Adjustments	(21,961)	(21,961)	0	(21,958)	(4)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(1,492)	(1,492)	0	(1,492)	0
13	Capitalized Other	(594)	(594)	0	(594)	0
14	Subtotal Deductions	215,069	215,796	727	212,371	3,425
	CCFT TAXES					
15	State Operating Expense Adjustment	5,433	5,433	0	5,433	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	590,918	590,095	(823)	578,800	11,295
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	60,071	60,071	0	56,522	3,550
20	Repair Allowance	53,843	53,843	0	53,296	548
21	Subtotal Deductions	925,334	925,239	(96)	906,421	18,817
22	Taxable Income for CCFT	895,303	801,929	(93,375)	820,984	(19,055)
23	CCFT	79,145	70,890	(8,254)	72,575	(1,684)
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	79,145	70,890	(8,254)	72,575	(1,684)
26	Defense Facilities Credit	0	0	0	0	0
27	Deferred Taxes - Interest	220	220	0	220	0
28	Deferred Taxes - Vacation	(132)	(132)	0	(132)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	0	0	0	0	0
31	Total CCFT	79,233	70,978	(8,254)	72,663	(1,684)
	FEDERAL TAXES					
32	CCFT - Prior Year	52,955	52,996	40	53,193	(197)
33	Federal Operating Expense Adjustment	5,688	5,688	0	5,688	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	583,458	582,635	(823)	569,071	13,564
37	Federal Tax Depreciation - Other	0	0	0	0	0

Table 1-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Distribution
($000)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
38	Removal Costs	60,071	60,071	0	56,522	3,550
39	Repair Allowance	28,992	28,992	0	28,697	295
40	Preferred Dividend Credit	311	311	0	311	0
41	Subtotal Deductions	946,544	946,489	(56)	925,852	20,637
42	Taxable Income for FIT	874,094	780,679	(93,415)	801,553	(20,874)
43	Federal Income Tax	305,933	273,238	(32,695)	280,544	(7,306)
44	Defense Facilities Credit	0	0	0	0	0
45	Flowback of Excess Deferred Taxes	0	0	0	0	0
46	Deferred Taxes - Interest	858	858	0	858	0
47	Deferred Taxes - Vacation	(476)	(476)	0	(476)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	5,165	32,405	27,240	22,683	9,722
50	**Total Federal Income Tax**	**311,480**	**306,024**	**(5,456)**	**303,608**	**2,416**

Table 1-4
2007 General Rate Case
Expense Summary – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Expenses in 2004 Dollars					
1	Production (Generation)					
2	Labor	0	0	0	0	0
3	Materials and Services	0	0	0	0	0
4	Other	0	0	0	0	0
5	Total	0	0	0	0	0
6	Transmission					
7	Labor	353	353	0	353	0
8	Materials and Services	290	290	0	290	0
9	Other	25	25	0	25	0
10	Total	669	669	0	669	0
11	Distribution					
12	Labor	209,152	208,461	(691)	201,150	7,311
13	Materials and Services	249,346	244,946	(4,400)	226,928	18,019
14	Other	0	0	0	0	0
15	Total	458,498	453,407	(5,091)	428,077	25,330
16	Customer Accounts					
17	Labor	154,615	152,962	(1,653)	152,494	468
18	Materials and Services	58,803	56,919	(1,884)	55,873	1,046
19	Other	12,898	12,898	0	12,898	0
20	Total	226,316	222,780	(3,537)	221,265	1,514
21	Customer Service					
22	Labor	2,563	2,563	0	2,562	1
23	Materials and Services	505	505	0	502	3
24	Other	0	0	0	0	0
25	Total	3,069	3,069	0	3,065	4
26	Administrative and General					
27	Labor	69,059	69,059	0	54,440	14,619
28	Materials and Services	67,715	53,428	(14,287)	45,154	8,274
29	Other	126,944	126,944	0	126,911	33
30	Wage Related	13,771	13,771	0	13,771	0
31	Medical	61,331	61,331	0	54,812	6,519
32	Total	338,820	324,533	(14,287)	295,088	29,445
33	**Total Expenses in 2004 Dollars**					
34	**Labor**	435,743	433,399	(2,344)	410,999	22,399
35	**Materials and Services**	376,659	356,088	(20,571)	328,747	27,341
36	**Other**	139,868	139,868	0	139,835	33
37	**Wage Related**	13,771	13,771	0	13,771	0
38	**Medical**	61,331	61,331	0	54,812	6,519

Table 1-4
2007 General Rate Case
Expense Summary – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
39	**Total**	1,027,372	1,004,457	(22,915)	948,164	56,293
40	**Total Expenses in 2007 Dollars**					
41	**Labor**	479,593	477,014	(2,580)	452,360	24,654
42	**Materials and Services**	401,961	379,654	(22,308)	350,781	28,873
43	**Other**	139,868	139,868	0	139,835	33
44	**Wage Related**	15,157	15,157	0	15,157	0
45	**Medical**	61,331	61,331	0	54,812	6,519
46	**Total**	1,097,911	1,073,023	(24,888)	1,012,944	60,079

Table 1-5
2007 General Rate Case
Franchise Fees and Uncollectible Accounts Expenses – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue					
2	Rate Case Revenues	3,085,964	2,965,600	(120,364)	2,902,990	62,610
3	Percent Of Revenue From Customers	99.8200%	99.8200%	99.8200%	99.8200%	99.8200%
4	Rate Case Revenues From Customers	3,080,409	2,960,262	(120,147)	2,897,764	62,498
	Uncollectible Accounts					
6	Uncollectible Rate	0.002772	0.002586	0.007355	0.002582	0.002771
7	Uncollectible Accounts Expense	8,539	7,655	(884)	7,482	173
8	Franchise Fees					
9	Rate Case Revenues From Customers	3,080,409	2,960,262	(120,147)	2,897,764	62,498
10	Uncollectible Accounts Expense	8,539	7,655	(884)	7,482	173
11	Net Rate Case Revenue From Customers	3,071,870	2,952,607	(119,263)	2,890,282	62,324
12	Franchise Rate	0.007603	0.007603	0.007603	0.007603	0.007603
13	Franchise Fees Expense	23,356	22,449	(907)	21,975	474

Table 1-6
2007 General Rate Case
Taxes Other than Income – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Property (Ad Valorem) Tax	97,415	97,402	(13)	97,215	188
2	Federal Insurance Contribution Act	32,642	32,466	(176)	30,788	1,678
3	Federal Unemployment Insurance	398	396	(2)	375	20
4	State Unemployment Insurance	2,039	2,028	(11)	1,923	105
5	San Francisco Payroll Tax	2,532	2,519	(14)	2,388	131
6	Total Payroll Taxes	37,611	37,409	(202)	35,475	1,934
7	Other Taxes	494	495	0	494	0
8	Total Taxes Other Than Income	135,520	135,305	(215)	133,184	2,122

Table 1-7
Plant in Service – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	13,848,856	13,848,856	0	13,848,856	0
3	Common, General, and Intangible	1,402,212	1,402,212	0	1,402,212	0
4	Total 2004 End-of-Year Plant	15,251,069	15,251,069	0	15,251,069	0
5	2005 Full-Year Net Additions					
6	Functional	596,079	596,079	0	595,833	246
7	Common, General, and Intangible	(43,354)	(43,354)	0	(43,342)	(12)
8	Total 2005 Net Additions	552,725	552,725	0	552,492	234
9	2005 End-of-Year Plant					
10	Functional	14,444,935	14,444,935	0	14,444,690	246
11	Common, General, and Intangible	1,358,859	1,358,859	0	1,358,871	(12)
12	Total 2005 End-of-Year Plant	15,803,794	15,803,794	0	15,803,560	234
13	2006 Full-Year Net Additions					
14	Functional	664,611	664,611	0	638,748	25,863
15	Common, General, and Intangible	69,317	66,845	(2,473)	61,154	5,690
16	Total 2006 Net Additions	733,929	731,456	(2,473)	699,903	31,553
17	2006 End-of-Year Plant					
18	Functional	15,109,547	15,109,547	0	15,083,438	26,109
19	Common, General, and Intangible	1,428,176	1,425,703	(2,473)	1,420,025	5,678
20	Total 2006 End-of-Year Plant	16,537,722	16,535,250	(2,473)	16,503,463	31,787
21	2007 Full-Year Net Additions					
22	Functional	731,135	731,135	0	690,371	40,764
23	Common, General, and Intangible	(34,203)	(34,203)	0	(51,305)	17,102
24	Total 2007 Net Additions	696,932	696,932	0	639,066	57,866
25	2007 End-of-Year Plant					
26	Functional	15,840,682	15,840,682	0	15,773,809	66,872
27	Common, General, and Intangible	1,393,973	1,391,500	(2,473)	1,368,720	22,781
28	Total 2007 End-of-Year Plant	17,234,654	17,232,182	(2,473)	17,142,529	89,653
29	**2007 Weighted Average Net Additions**					
30	Functional	337,137	337,137	0	321,579	15,558
31	Common, General, and Intangible	(64,637)	(64,637)	0	(71,401)	6,763
32	Total 2007 Weighted Average Net Additions	272,499	272,499	0	250,178	22,321
33	**2007 Weighted Average Plant**					
34	Functional	15,446,683	15,446,683	0	15,405,017	41,667
35	Common, General, and Intangible	1,363,538	1,361,066	(2,473)	1,348,624	12,441
36	Total 2007 Weighted Average Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108

Table 1-8
2007 General Rate Case
Depreciation – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Depreciation					
1	Production	4	4	-	4	-
2	Transmission	645	628	(17)	645	(17)
3	Distribution	611,385	529,459	(81,926)	541,708	(12,249)
4	General	3,077	3,077	-	3,086	(10)
5	Subtotal	615,111	533,167	(81,944)	545,443	(12,276)
6	Common Utility Allocation	63,697	63,532	(165)	62,516	1,016
7	Total	678,808	596,699	(82,109)	607,960	(11,260)
	Depreciation Reserve					
8	Production	202	202	-	202	-
9	Transmission	11,947	11,929	(17)	11,947	(17)
10	Distribution	6,854,387	6,772,460	(81,926)	6,795,933	(23,473)
11	General	31,786	31,786	-	31,996	(209)
12	Subtotal	6,898,321	6,816,377	(81,944)	6,840,076	(23,699)
13	Common Utility Allocation	511,222	510,954	(268)	540,814	(29,859)
14	Total	7,409,543	7,327,332	(82,212)	7,380,890	(53,559)
	Weighted Average Depreciation Reserve					
8	Production	200	200	-	200	-
9	Transmission	11,624	11,615	(9)	11,624	(9)
10	Distribution	6,617,361	6,576,398	(40,963)	6,589,299	(12,901)
11	General	34,198	34,198	-	34,403	(204)
12	Subtotal	6,663,383	6,622,411	(40,972)	6,635,525	(13,114)
13	Common Utility Allocation	530,289	530,103	(185)	541,498	(11,394)
14	Total	7,193,672	7,152,515	(41,157)	7,177,023	(24,509)

Table 1-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	0	0	0	0	0
2	Special Deposits and Working Funds	106	106	(0)	106	0
3	Other Receivables	50,952	50,911	(41)	50,908	2
4	Prepayments	6,555	6,555	0	6,555	0
5	Deferred Debits, Company-Wide	(356)	(355)	0	(355)	(0)
	Less					
6	Working Cash Capital not Supplied by Investors	3,892	3,892	0	3,892	(0)
7	Goods Delivered to Construction Sites	1,523	1,523	0	1,523	0
8	Accrued Vacation	68,438	68,070	(368)	64,552	3,518
	Add					
9	Prepayment, Departmental	9,829	9,829	0	9,829	0
10	Total Operational Cash Requirement	(6,767)	(6,439)	327	(2,924)	(3,516)
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	59,161	60,380	1,219	12,158	48,222
12	Working Cash Capital Supplied by Investors	52,394	53,941	1,547	9,234	44,706

Table 1-10
2007 General Rate Case
Rate Base – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	WEIGHTED AVERAGE PLANT					
1	Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant - Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	16,810,221	16,807,749	(2,473)	16,753,641	54,108
	WORKING CAPITAL					
6	Material and Supplies - Fuel	0	0	0	0	0
7	Material and Supplies - Other	29,880	29,880	0	29,880	0
8	Working Cash	52,394	53,941	1,547	9,234	44,706
9	Total Working Capital	82,275	83,821	1,547	39,115	44,706
	ADJUSTMENTS FOR TAX REFORM ACT					
10	Deferred Capitalized Interest	2,751	2,751	0	2,751	0
11	Deferred Vacation	22,661	22,661	0	22,661	0
12	Deferred CIAC Tax Effects	265,556	265,556	0	265,556	0
13	Total Adjustments	290,969	290,969	0	290,969	0
	LESS DEDUCTIONS					
14	Customer Advances	95,939	95,939	0	95,939	0
15	Accumulated Deferred Taxes - Defense	0	0	0	0	0
16	Accumulated Deferred Taxes - Fixed Assets	1,292,286	1,305,797	13,512	1,299,571	6,227
17	Accumulated Deferred Taxes - Other	0	0	0	0	0
18	Deferred ITC	55,854	55,854	0	55,854	0
19	Deferred Tax - Other	0	0	0	0	0
20	Total Deductions	1,444,078	1,457,590	13,512	1,451,363	6,227
21	DEPRECIATION RESERVE	7,193,747	7,152,589	(41,157)	7,177,098	(24,509)
22	TOTAL RATE BASE	8,545,639	8,572,359	26,720	8,455,263	117,096

Table 1-11
2007 General Rate Case
Net To Gross Multiplier – Test Year 2007
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue Base	1.000000	1.000000	0.000000	1.000000	0.000000
2	Less Interdepartmental Revenue	0.001800	0.001800	0.000000	0.001800	0.000000
3	Percent Revenue From Jurisdictional Customers	0.998200	0.998200	0.000000	0.998200	0.000000
4	Uncollectibles Percentage	0.002767	0.002581	(0.000186)	0.002577	0.000004
5	Franchise Requirements	0.007568	0.007570	0.000001	0.007570	(0.000000)
6	Total Uncollectibles and Franchise Requirements	0.010335	0.010151	(0.000184)	0.010147	0.000004
7	Net For State Income Taxes	0.989665	0.989849	0.000184	0.989853	(0.000004)
8	State Income Tax Percentage	0.088400	0.088400	0.000000	0.088400	0.000000
9	State Income Taxes	0.087486	0.087503	0.000016	0.087503	(0.000000)
10	Net For Federal Income Taxes	0.989665	0.989849	0.000184	0.989853	(0.000004)
11	Federal Income Tax Percentage	0.350000	0.350000	0.000000	0.350000	0.000000
12	Federal Income Taxes	0.346383	0.346447	0.000064	0.346449	(0.000001)
13	Net Operating Revenue	0.555796	0.555899	0.000103	0.555901	(0.000002)
14	Net To Gross Multiplier	1.799222	1.798887	(0.000335)	1.798880	0.000007

Table 2-1
2007 General Rate Case
Revenue Gas – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUES AT PRESENT RATES					
	CPUC Revenues (Retail)					
1	Revenues from Sales	1,026,891	1,026,891	0	1,026,891	0
2	Plus: Non-Applicable Revenue	0	0	0	0	0
3	CPUC Revenue	1,026,891	1,026,891	0	1,026,891	0
4	Plus: Adopted Other Operating Revenue	16,300	16,300	0	16,300	0
5	Rate Case Revenue	1,043,191	1,043,191	0	1,043,191	0
	FERC Revenues (Wholesale)					
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	0	0
8	FERC Revenue	0	0	0	0	0
9	Plus: Other Operating Revenue	0	0	0	0	0
10	Rate Case Revenue	0	0	0	0	0
11	Total Rate Case Revenue	1,043,191	1,043,191	0	1,043,191	0
	INCREASE IN RATE CASE REVENUE					
12	CPUC Jurisdiction	45,209	30,253	(14,955)	(15,989)	46,242
13	FERC Jurisdiction	0	0	0	0	0
14	Total Increase	45,209	30,253	(14,955)	(15,989)	46,242
15	Percent	4.33%	2.90%		(1.53%)	
	INCREASE IN CPUC REVENUE FROM SALES					
16	Amount	35,485	20,530	(14,955)	(25,262)	45,792
17	Percent	3.46%	2.00%		(2.46%)	
	REVENUES AT PROPOSED RATES					
	CPUC Revenues (Retail)					
18	Revenues from Sales	1,062,376	1,047,421	(14,955)	1,001,629	45,792
19	Plus: Non-Applicable Revenue	0	0	0	0	0
20	CPUC Revenue	1,062,376	1,047,421	(14,955)	1,001,629	45,792
21	Plus: Other Operating Revenue	26,024	26,024	0	25,573	451
22	Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242
	FERC Revenues (Wholesale)					
23	Revenues from Sales	0	0	0	0	0
24	Plus: Non-Applicable Revenue	0	0	0	0	0
25	FERC Revenue	0	0	0	0	0
26	Plus: Other Operating Revenue	0	0	0	0	0
27	Rate Case Revenue	0	0	0	0	0
28	Total Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242

Table 2-2
2007 General Rate Case
Results of Operations – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUE					
1	Revenue at Effective Rates	1,088,400	1,073,444	(14,955)	1,027,202	46,242
2	Less Non-General Revenue	0	0	0	0	0
3	General Rate Case Revenue	1,088,400	1,073,444	(14,955)	1,027,202	46,242
	OPERATING EXPENSES					
4	Energy Costs	0	0	0	0	0
5	Other Production	0	0	0	0	0
6	Storage	0	0	0	0	0
7	Transmission	3,208	3,208	0	3,789	(581)
8	Distribution	139,320	136,650	(2,671)	129,165	7,485
9	Customer Accounts	174,938	172,211	(2,727)	171,813	398
10	Uncollectibles	2,946	2,710	(235)	2,589	121
11	Customer Services	12,106	12,106	0	8,488	3,618
12	Administrative and General	197,892	189,154	(8,738)	171,415	17,739
13	Franchise Requirements	10,316	10,177	(140)	9,738	438
14	Amortization	0	0	0	0	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(186)	(186)	0	0	(186)
18	Subtotal Expenses	540,539	526,028	(14,511)	496,997	29,031
	TAXES					
19	Superfund	0	0	0	0	0
20	Property	24,423	24,416	(7)	24,353	63
21	Payroll	21,534	21,350	(184)	20,443	907
22	Business	221	221	(1)	223	(2)
23	Other	62	62	(0)	62	(1)
24	State Corporation Franchise	20,190	20,213	23	19,398	815
25	Federal Income	78,826	78,780	(47)	77,035	1,745
26	Total Taxes	145,256	145,041	(216)	141,514	3,527
27	**DEPRECIATION**	209,484	209,392	(92)	199,345	10,047
28	Fossil Decommissioning	0	0	0	0	0
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	895,280	880,461	(14,819)	837,856	42,605
31	**Net for Return**	193,120	192,984	(137)	189,346	3,637
32	**Rate Base**	2,197,395	2,195,839	(1,556)	2,154,456	41,383
	RATE OF RETURN					
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 2-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than n PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	1,088,400	1,073,444	(14,955)	1,027,202	46,242
2	O&M Expenses	540,539	526,028	(14,511)	496,997	29,031
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	46,240	46,048	(192)	45,081	967
6	Subtotal	501,621	501,368	(253)	485,124	16,244
	DEDUCTIONS FROM TAXABLE INCOME					
7	Interest Charges	60,850	60,807	(43)	59,661	1,146
8	Fiscal/Calendar Adjustment	542	535	(7)	474	62
9	Operating Expense Adjustments	(11,967)	(11,967)	0	(11,944)	(23)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(251)	(251)	0	(251)	0
13	Capitalized Other	(486)	(486)	0	(486)	0
14	Subtotal Deductions	48,689	48,638	(50)	47,453	1,185
	CCFT TAXES					
15	State Operating Expense Adjustment	1,480	1,480	0	1,480	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	213,933	213,473	(461)	208,261	5,212
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	9,425	9,425	0	8,799	626
20	Repair Allowance	0	0	0	0	0
21	Subtotal Deductions	273,527	273,015	(511)	265,993	7,023
22	Taxable Income for CCFT	228,094	228,353	258	219,132	9,221
23	CCFT	20,164	20,186	23	19,371	815
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	20,164	20,186	23	19,371	815
26	Defense Facilities Credit	0	0	0	0	0
27	Deferred Taxes - Interest	48	48	0	48	0
28	Deferred Taxes - Vacation	(22)	(22)	0	(22)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	0	0	0	0	0
31	Total CCFT	20,190	20,213	23	19,398	815

Table 2-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than n PG&E	DRA	Settlmt. +/- than DRA
	FEDERAL TAXES					
32	CCFT - Prior Year	18,298	18,321	23	18,340	(19)
33	Federal Operating Expense Adjustment	1,639	1,639	0	1,639	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	229,757	229,296	(461)	222,496	6,800
37	Federal Tax Depreciation - Other	0	0	0	0	0
38	Removal Costs	9,425	9,425	0	8,799	626
39	Repair Allowance	0	0	0	0	0
40	Preferred Dividend Credit	40	40	0	40	0
41	Subtotal Deductions	307,849	307,360	(489)	298,768	8,592
42	Taxable Income for FIT	193,772	194,008	236	186,356	7,652
43	Federal Income Tax	67,820	67,903	83	65,225	2,678
44	Defense Facilities Credit	0	0	0	0	0
45	Flowback of Excess Deferred Taxes	0	0	0	0	0
46	Deferred Taxes - Interest	234	234	0	234	0
47	Deferred Taxes - Vacation	(80)	(80)	0	(80)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	10,853	10,723	(129)	11,657	(933)
50	Total Federal Income Tax	78,826	78,780	(47)	77,035	1,745

Table 2-4
2007 General Rate Case
Expense Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Expenses in 2004 Dollars					
1	Production (Generation)					
2	Labor	0	0	0	0	0
3	Materials and Services	0	0	0	0	0
4	Other	0	0	0	0	0
5	Total	0	0	0	0	0
6	Transmission and Storage					
7	Labor	2,367	2,367	0	2,795	(429)
8	Materials and Services	566	566	0	669	(103)
9	Other	0	0	0	0	0
10	Total	2,932	2,932	0	3,464	(532)
11	Distribution					
12	Labor	98,866	97,856	(1,010)	95,289	2,567
13	Materials and Services	28,610	27,148	(1,462)	22,777	4,370
14	Other	0	0	0	0	0
15	Total	127,476	125,004	(2,472)	118,067	6,937
16	Customer Accounts					
17	Labor	108,250	107,129	(1,122)	107,303	(174)
18	Materials and Services	41,421	40,055	(1,366)	39,515	540
19	Other	10,553	10,553	0	10,553	0
20	Total	160,225	157,737	(2,488)	157,371	365
21	Customer Service					
22	Labor	1,328	1,328	0	972	356
23	Materials and Services	9,745	9,745	0	6,792	2,953
24	Other	0	0	0	0	0
25	Total	11,073	11,073	0	7,764	3,309
26	Administrative and General					
27	Labor	38,671	38,671	0	30,485	8,186
28	Materials and Services	37,918	29,918	(8,000)	25,285	4,633
29	Other	71,084	71,084	0	71,066	19
30	Wage Related	7,711	7,711	0	7,711	0
31	Medical	34,344	34,344	0	30,693	3,651
32	Total	189,728	181,727	(8,000)	165,239	16,488

Table 2-4
2007 General Rate Case
Expense Summary – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
33	**Total Expenses in 2004 Dollars**					
34	**Labor**	249,481	247,349	(2,132)	236,843	10,506
35	**Materials and Services**	118,260	107,432	(10,829)	95,038	12,393
36	**Other**	81,638	81,638	0	81,619	19
37	**Wage Related**	7,711	7,711	0	7,711	0
38	**Medical**	34,344	34,344	0	30,693	3,651
39	**Total**	491,434	478,473	(12,960)	451,905	26,569
40	**Total Expenses in 2007 Dollars**					
41	**Labor**	274,588	272,241	(2,346)	260,678	11,563
42	**Materials and Services**	128,221	116,432	(11,789)	103,193	13,239
43	**Other**	81,638	81,638	0	81,619	19
44	**Wage Related**	8,487	8,487	0	8,487	0
45	**Medical**	34,344	34,344	0	30,693	3,651
46	**Total**	527,277	513,142	(14,135)	484,669	28,472

Table 2-5
2007 General Rate Case
Franchise Fees and Uncollectible Accounts Expense – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue					
2	Rate Case Revenues	1,088,400	1,073,444	(14,955)	1,027,202	46,242
3	Percent Of Revenue From Customers	97.6300%	97.6300%	97.6300%	97.6300%	97.6300%
4	Rate Case Revenues From Customers	1,062,605	1,048,004	(14,601)	1,002,858	45,146
5	Uncollectible Accounts					
6	Uncollectible Rate	0.002772	0.002586	0.016122	0.002582	0.002675
7	Uncollectible Accounts Expense	2,946	2,710	(235)	2,589	121
8	Franchise Fees					
9	Rate Case Revenues From Customers	1,062,605	1,048,004	(14,601)	1,002,858	45,146
10	Uncollectible Accounts Expense	2,946	2,710	(235)	2,589	121
11	Net Rate Case Revenue From Customers	1,059,659	1,045,294	(14,366)	1,000,268	45,025
12	Franchise Rate	0.009736	0.009736	0.009736	0.009736	0.009736
13	Franchise Fees Expense	10,316	10,177	(140)	9,738	438

Table 2-6
2007 General Rate Case
Taxes Other than Income – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Property (Ad Valorem) Tax	24,423	24,416	(7)	24,353	63
2	Federal Insurance Contribution Act	18,689	18,529	(160)	17,742	787
3	Federal Unemployment Insurance	228	226	(2)	216	10
4	State Unemployment Insurance	1,167	1,157	(10)	1,108	49
5	San Francisco Payroll Tax	1,450	1,438	(12)	1,376	61
6	Total Payroll Taxes	21,534	21,350	(184)	20,443	907
7	Other Taxes	283	282	(1)	285	(3)
8	Total Taxes Other Than Income	46,240	46,048	(192)	45,081	967

Table 2-7
2007 General Rate Case
Plant in Service – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	4,649,137	4,649,137	0	4,649,137	0
3	Common, General, and Intangible	925,937	925,937	0	925,937	0
4	Total 2004 End-of-Year Plant	5,575,073	5,575,073	0	5,575,073	0
5	2005 Full-Year Net Additions					
6	Functional	175,811	175,811	0	175,811	0
7	Common, General, and Intangible	(13,432)	(13,432)	0	(13,517)	85
8	Total 2005 Net Additions	162,379	162,379	0	162,294	85
9	2005 End-of-Year Plant					
10	Functional	4,824,948	4,824,948	0	4,824,948	0
11	Common, General, and Intangible	912,505	912,505	0	912,420	85
12	Total 2005 End-of-Year Plant	5,737,453	5,737,453	0	5,737,367	85
13	2006 Full-Year Net Additions					
14	Functional	173,111	173,111	0	165,542	7,569
15	Common, General, and Intangible	40,365	38,981	(1,385)	35,919	3,062
16	Total 2006 Net Additions	213,477	212,092	(1,385)	201,461	10,631
17	2006 End-of-Year Plant					
18	Functional	4,998,059	4,998,059	0	4,990,490	7,569
19	Common, General, and Intangible	952,870	951,486	(1,385)	948,339	3,147
20	Total 2006 End-of-Year Plant	5,950,929	5,949,545	(1,385)	5,938,829	10,716
21	2007 Full-Year Net Additions					
22	Functional	180,682	180,682	0	170,348	10,333
23	Common, General, and Intangible	27,061	27,061	0	17,602	9,459
24	Total 2007 Net Additions	207,743	207,743	0	187,950	19,792
25	2007 End-of-Year Plant					
26	Functional	5,178,740	5,178,740	0	5,160,838	17,902
27	Common, General, and Intangible	979,931	978,547	(1,385)	965,941	12,606
28	Total 2007 End-of-Year Plant	6,158,672	6,157,287	(1,385)	6,126,779	30,508
29	**2007 Weighted Average Net Additions**					
30	Functional	91,493	91,493	0	86,327	5,167
31	Common, General, and Intangible	6,565	6,565	0	2,845	3,719
32	Total 2007 Weighted Average Net Additions	98,058	98,058	0	89,172	8,886
33	**2007 Weighted Average Plant**					
34	Functional	5,089,552	5,089,552	0	5,076,817	12,736
35	Common, General, and Intangible	959,435	958,050	(1,385)	951,184	6,866
36	Total 2007 Weighted Average Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602

Table 2-8
2007 General Rate Case
Depreciation – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Depreciation					
1	Production	523	523	-	523	-
2	Transmission	152	152	-	152	-
3	Distribution	163,316	163,316	-	153,797	9,519
4	General	781	781	-	781	-
5	Subtotal	164,773	164,773	-	155,253	9,519
6	Common Utility Allocation	44,710	44,618	(92)	44,091	527
7	Total	209,483	209,391	(92)	199,344	10,047
	Depreciation Reserve					
8	Production	4,470	4,470	-	4,470	-
9	Transmission	1,524	1,524	-	1,524	-
10	Distribution	3,246,020	3,246,020	-	3,238,852	7,169
11	General	8,211	8,211	-	8,211	-
12	Subtotal	3,260,226	3,260,226	-	3,253,057	7,169
13	Common Utility Allocation	419,069	418,919	(150)	435,702	(16,783)
14	Total	3,679,295	3,679,145	(150)	3,688,759	(9,615)
	Weighted Average Depreciation Reserve					
8	Production	4,209	4,209	-	4,209	-
9	Transmission	1,447	1,447	-	1,447	-
10	Distribution	3,176,628	3,176,628	-	3,173,508	3,120
11	General	8,788	8,788	-	8,788	-
12	Subtotal	3,191,072	3,191,072	-	3,187,952	3,120
13	Common Utility Allocation	423,650	423,546	(104)	429,969	(6,423)
14	Total	3,614,722	3,614,618	(104)	3,617,921	(3,303)

Table 2-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	0	0	0	0	0
2	Special Deposits and Working Funds	61	61	(0)	61	(0)
3	Other Receivables	28,977	28,969	(8)	28,978	(8)
4	Prepayments	3,671	3,671	0	3,671	0
5	Deferred Debits, Company-Wide	(203)	(203)	0	(203)	0
	Less					
6	Working Cash Capital not Supplied by Investors	2,179	2,179	(0)	2,179	0
7	Goods Delivered to Construction Sites	853	853	0	853	0
8	Accrued Vacation	39,184	38,849	(335)	37,199	1,650
	Add					
9	Prepayment, Departmental	1,955	1,955	0	1,955	0
10	Total Operational Cash Requirement	(7,756)	(7,428)	327	(5,770)	(1,658)
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	64,537	63,810	(728)	43,716	20,094
12	Working Cash Capital Supplied by Investors	56,782	56,381	(400)	37,946	18,435

Table 2-10
2007 General Rate Case
Rate Base – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	WEIGHTED AVERAGE PLANT					
1	Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant - Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	6,048,987	6,047,603	(1,385)	6,028,001	19,602
	WORKING CAPITAL					
6	Material and Supplies - Fuel	0	0	0	0	0
7	Material and Supplies - Other	3,198	3,198	0	3,198	0
8	Working Cash	56,782	56,381	(400)	37,946	18,435
9	Total Working Capital	59,980	59,580	(400)	41,144	18,435
	ADJUSTMENTS FOR TAX REFORM ACT					
10	Deferred Capitalized Interest	2,397	2,397	0	2,397	0
11	Deferred Vacation	3,809	3,809	0	3,809	0
12	Deferred CIAC Tax Effects	53,920	53,920	0	53,920	0
13	Total Adjustments	60,126	60,126	0	60,126	0
	LESS DEDUCTIONS					
14	Customer Advances	29,485	29,485	0	29,485	0
15	Accumulated Deferred Taxes - Defense	0	0	0	0	0
16	Accumulated Deferred Taxes - Fixed Assets	301,416	301,291	(125)	301,334	(43)
17	Accumulated Deferred Taxes - Other	0	0	0	0	0
18	Deferred ITC	26,072	26,072	0	26,072	0
19	Deferred Tax - Other	0	0	0	0	0
20	Total Deductions	356,974	356,849	(125)	356,892	(43)
21	DEPRECIATION RESERVE	3,614,724	3,614,620	(104)	3,617,924	(3,303)
22	TOTAL RATE BASE	2,197,395	2,195,839	(1,556)	2,154,456	41,383

Table 2-11
2007 General Rate Case
Net TO Gross Multiplier – Test Year 2007
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue Base	1.000000	1.000000	0.000000	1.000000	0.000000
2	Less Interdepartmental Revenue	0.023700	0.023700	0.000000	0.023700	0.000000
3	Percent Revenue From Jurisdictional Customers	0.976300	0.976300	0.000000	0.976300	0.000000
4	Uncollectibles Percentage	0.002706	0.002525	(0.000182)	0.002521	0.000004
5	Franchise Requirements	0.009478	0.009480	0.000002	0.009480	(0.000000)
6	Total Uncollectibles and Franchise Requirements	0.012185	0.012005	(0.000180)	0.012001	0.000004
7	Net For State Income Taxes	0.987815	0.987995	0.000180	0.987999	(0.000004)
8	State Income Tax Percentage	0.088400	0.088400	0.000000	0.088400	0.000000
9	State Income Taxes	0.087323	0.087339	0.000016	0.087339	(0.000000)
10	Net For Federal Income Taxes	0.987815	0.987995	0.000180	0.987999	(0.000004)
11	Federal Income Tax Percentage	0.350000	0.350000	0.000000	0.350000	0.000000
12	Federal Income Taxes	0.345735	0.345798	0.000063	0.345800	(0.000001)
13	Net Operating Revenue	0.554757	0.554858	0.000101	0.554860	(0.000002)
14	Net To Gross Multiplier	1.802591	1.802263	(0.000328)	1.802256	0.000007

Table 3-1
2007 General Rate Case
Revenue Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUES AT PRESENT RATES					
	CPUC Revenues (Retail)					
1	Revenues from Sales	1,038,095	1,038,095	0	1,038,095	0
2	Plus: Non-Applicable Revenue	1,351	1,351	0	1,351	0
3	CPUC Revenue	1,039,446	1,039,446	0	1,039,446	0
4	Plus: Adopted Other Operating Revenue	8,159	8,159	0	8,159	0
5	Rate Case Revenue	1,047,605	1,047,605	0	1,047,605	0
	FERC Revenues (Wholesale)					
6	Revenues from Sales	0	0	0	0	0
7	Plus: Non-Applicable Revenue	0	0	0	(91)	91
8	FERC Revenue	0	0	0	(91)	91
9	Plus: Other Operating Revenue	0	0	0	91	(91)
10	Rate Case Revenue	0	0	0	0	0
11	Total Rate Case Revenue	1,047,605	1,047,605	0	1,047,605	0
	INCREASE IN RATE CASE REVENUE					
12	CPUC Jurisdiction	17,790	(27,850)	(45,639)	(114,284)	86,434
13	FERC Jurisdiction	0	0	0	0	0
14	Total Increase	17,790	(27,850)	(45,639)	(114,284)	86,434
15	Percent	1.70%	(2.66%)		(10.91%)	
	INCREASE IN CPUC REVENUE FROM SALES					
16	Amount	16,258	(29,811)	(46,069)	(115,453)	85,642
17	Percent	1.57%	(2.87%)		(11.12%)	
	REVENUES AT PROPOSED RATES					
	CPUC Revenues (Retail)					
18	Revenues from Sales	1,054,353	1,008,284	(46,069)	922,642	85,642
19	Plus: Non-Applicable Revenue	1,351	1,351	0	1,351	0
20	CPUC Revenue	1,055,704	1,009,635	(46,069)	923,993	85,642
21	Plus: Other Operating Revenue	9,690	10,120	430	9,328	792
22	Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434
	FERC Revenues (Wholesale)					
23	Revenues from Sales	0	0	0	0	0
24	Plus: Non-Applicable Revenue	0	0	0	(91)	91
25	FERC Revenue	0	0	0	(91)	91
26	Plus: Other Operating Revenue	0	0	0	91	(91)
27	Rate Case Revenue	0	0	0	0	0
28	Total Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434

Table 3-2
2007 General Rate Case
Results of Operations – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	REVENUE					
1	Revenue at Effective Rates	1,064,044	1,018,404	(45,639)	932,061	86,343
2	Less Non-General Revenue	1,351	1,351	0	1,260	91
3	General Rate Case Revenue	1,065,395	1,019,755	(45,639)	933,321	86,434
	OPERATING EXPENSES					
4	Energy Costs	0	0	0	0	0
5	Other Production	451,388	445,018	(6,370)	400,732	44,286
6	Storage	0	0	0	0	0
7	Transmission	5,603	5,603	0	5,603	0
8	Distribution	0	0	0	0	0
9	Customer Accounts	0	0	0	0	0
10	Uncollectibles	2,948	2,632	(316)	2,405	227
11	Customer Services	0	0	0	0	0
12	Administrative and General	190,877	182,449	(8,428)	165,339	17,110
13	Franchise Requirements	8,063	7,719	(344)	7,065	654
14	Amortization	6,476	6,476	0	6,476	0
15	Wage Change Impacts	0	0	0	0	0
16	Other Price Change Impacts	0	0	0	0	0
17	Other Adjustments	(179)	(179)	0	0	(179)
18	Subtotal Expenses	665,176	649,719	(15,458)	587,621	62,098
	TAXES					
19	Superfund	0	0	0	0	0
20	Property	24,525	24,518	(7)	24,494	24
21	Payroll	21,654	21,485	(170)	19,759	1,726
22	Business	222	222	(0)	215	7
23	Other	62	62	(0)	60	2
24	State Corporation Franchise	14,398	12,298	(2,100)	11,146	1,152
25	Federal Income	54,535	46,245	(8,290)	39,958	6,287
26	Total Taxes	115,397	104,830	(10,567)	95,632	9,198
27	Depreciation	135,599	135,416	(183)	131,361	4,055
28	Fossil Decommissioning	(26,812)	(26,812)	0	(33,994)	7,182
29	Nuclear Decommissioning	0	0	0	0	0
30	Total Operating Expenses	889,360	863,153	(26,207)	780,619	82,533

Table 3-2
2007 General Rate Case
Results of Operations – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
31	Net for Return	176,035	156,603	(19,432)	152,702	3,901
32	Rate Base	2,002,989	1,781,886	(221,104)	1,737,502	44,384
	RATE OF RETURN					
33	On Rate Base	8.79%	8.79%	0.00%	8.79%	0.00%
34	On Equity	11.35%	11.35%	0.00%	11.35%	0.00%

Table 3-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenues	1,065,395	1,019,755	(45,639)	933,321	86,434
2	O&M Expenses	665,176	649,719	(15,458)	587,621	62,098
3	Nuclear Decommissioning Expense	0	0	0	0	0
4	Superfund Tax	0	0	0	0	0
5	Taxes Other Than Income	46,464	46,287	(177)	44,529	1,758
6	Subtotal	353,754	323,749	(30,005)	301,172	22,578
	DEDUCTIONS FROM TAXABLE INCOME					
7	Interest Charges	55,467	49,344	(6,123)	48,115	1,229
8	Fiscal/Calendar Adjustment	434	427	(7)	403	24
9	Operating Expense Adjustments	6,100	6,100	0	6,125	(25)
10	Capitalized Interest Adjustment	0	0	0	0	0
11	Capitalized Inventory Adjustment	0	0	0	0	0
12	Vacation Accrual Reduction	(775)	(775)	0	(775)	0
13	Capitalized Other	0	0	0	0	0
14	Subtotal Deductions	61,226	55,096	(6,130)	53,868	1,228
	CCFT TAXES					
15	State Operating Expense Adjustment	1,217	1,217	0	1,217	0
16	State Tax Depreciation - Declining Balance	0	0	0	0	0
17	State Tax Depreciation - Fixed Assets	158,605	158,160	(444)	151,949	6,211
18	State Tax Depreciation - Other	0	0	0	0	0
19	Removal Costs	2,280	2,280	0	2,163	117
20	Repair Allowance	0	0	0	0	0
21	Subtotal Deductions	223,328	216,754	(6,574)	209,197	7,556
22	Taxable Income for CCFT	130,426	106,996	(23,430)	91,975	15,021
23	CCFT	11,530	9,458	(2,071)	8,131	1,328
24	State Tax Adjustment	0	0	0	0	0
25	Current CCFT	11,530	9,458	(2,071)	8,131	1,328
26	Defense Facilities Credit	1,660	1,660	0	1,660	0
27	Deferred Taxes - Interest	81	81	0	81	0
28	Deferred Taxes - Vacation	(69)	(69)	0	(69)	0
29	Deferred Taxes - Other	0	0	0	0	0
30	Deferred Taxes - Fixed Assets	1,196	1,167	(29)	1,342	(175)
31	Total CCFT	14,398	12,298	(2,100)	11,146	1,152

Table 3-3
2007 General Rate Case
Income Tax Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	FEDERAL TAXES					
32	CCFT - Prior Year	14,702	14,724	22	15,291	(568)
33	Federal Operating Expense Adjustment	1,540	1,540	0	1,540	0
34	Federal Tax Depreciation - Declining Balance	0	0	0	0	0
35	Federal Tax Depreciation - SLRL	0	0	0	0	0
36	Federal Tax Depreciation - Fixed Assets	138,397	137,952	(445)	129,034	8,918
37	Federal Tax Depreciation - Other	0	0	0	0	0
38	Removal Costs	2,280	2,280	0	2,163	117
39	Repair Allowance	0	0	0	0	0
40	Preferred Dividend Credit	2,299	2,299	0	2,299	0
41	Subtotal Deductions	220,444	213,891	(6,552)	204,196	9,695
42	Taxable Income for FIT	133,310	109,858	(23,452)	96,976	12,882
43	Federal Income Tax	46,659	38,450	(8,208)	33,942	4,509
44	Defense Facilities Credit	5,992	5,992	0	5,992	0
45	Flowback of Excess Deferred Taxes	(2,788)	(2,788)	0	(2,788)	0
46	Deferred Taxes - Interest	413	413	0	413	0
47	Deferred Taxes - Vacation	(247)	(247)	0	(247)	0
48	Deferred Taxes - Other	0	0	0	0	0
49	Deferred Taxes - Fixed Assets	4,506	4,424	(82)	2,646	1,778
50	Total Federal Income Tax	54,535	46,245	(8,290)	39,958	6,287

Table 3-4
2007 General Rate Case
Expense Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Expenses in 2004 Dollars					
1	Production (Generation)					
2	Labor	210,614	208,648	(1,966)	196,553	12,095
3	Materials and Services	205,672	201,726	(3,945)	172,717	29,009
4	Other	0	0	0	0	0
5	Total	416,286	410,375	(5,911)	369,270	41,104
6	Transmission					
7	Labor	2,966	2,966	0	2,966	0
8	Materials and Services	2,055	2,055	0	2,055	0
9	Other	134	134	0	134	0
10	Total	5,154	5,154	0	5,154	0
11	Distribution					
12	Labor	0	0	0	0	0
13	Materials and Services	0	0	0	0	0
14	Other	0	0	0	0	0
15	Total	0	0	0	0	0
16	Customer Accounts					
17	Labor	0	0	0	0	0
18	Materials and Services	0	0	0	0	0
19	Other	0	0	0	0	0
20	Total	0	0	0	0	0
21	Customer Service					
22	Labor	0	0	0	0	0
23	Materials and Services	0	0	0	0	0
24	Other	0	0	0	0	0
25	Total	0	0	0	0	0
26	Administrative and General					
27	Labor	37,300	37,300	0	29,404	7,896
28	Materials and Services	36,574	28,857	(7,717)	24,389	4,469
29	Other	68,565	68,565	0	68,547	18
30	Wage Related	7,441	7,441	0	7,441	0
31	Medical	33,126	33,126	0	29,605	3,521
32	Total	183,006	175,289	(7,717)	159,386	15,904

Table 3-4
2007 General Rate Case
Expense Summary – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
33	**Total Expenses in 2004 Dollars**					
34	**Labor**	250,880	248,914	(1,966)	228,924	19,990
35	**Materials and Services**	244,301	232,639	(11,662)	199,160	33,478
36	**Other**	68,698	68,698	0	68,680	18
37	**Wage Related**	7,441	7,441	0	7,441	0
38	**Medical**	33,126	33,126	0	29,605	3,521
39	**Total**	604,446	590,818	(13,628)	533,810	57,008
40	**Total Expenses in 2007 Dollars**					
41	**Labor**	276,127	273,963	(2,163)	251,961	22,002
42	**Materials and Services**	261,552	248,918	(12,634)	213,242	35,676
43	**Other**	68,698	68,698	0	68,680	18
44	**Wage Related**	8,186	8,186	0	8,186	0
45	**Medical**	33,126	33,126	0	29,605	3,521
46	**Total**	647,689	632,892	(14,798)	571,675	61,217

Table 3-5
2007 General Rate Case
Franchise Fees and Uncollectibles Expense – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Revenue					
2	Rate Case Revenues	1,065,395	1,019,755	(45,639)	933,321	86,434
3	Percent Of Revenue From Customers	99.8200%	99.8200%	99.8200%	99.8200%	99.8200%
4	Rate Case Revenues From Customers	1,063,477	1,017,920	(45,557)	931,641	86,278
5	Uncollectible Accounts					
6	Uncollectible Rate	0.002772	0.002586	0.006928	0.002582	0.002629
7	Uncollectible Accounts Expense	2,948	2,632	(316)	2,405	227
8	Franchise Fees					
9	Rate Case Revenues From Customers	1,063,477	1,017,920	(45,557)	931,641	86,278
10	Uncollectible Accounts Expense	2,948	2,632	(316)	2,405	227
11	Net Rate Case Revenue From Customers	1,060,529	1,015,287	(45,242)	929,236	86,052
12	Franchise Rate	0.007603	0.007603	0.007603	0.007603	0.007603
13	Franchise Fees Expense	8,063	7,719	(344)	7,065	654

Table 3-6
2007 General Rate Case
Taxes Other than Income – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	Property (Ad Valorem) Tax	24,525	24,518	(7)	24,494	24
2	Federal Insurance Contribution Act	18,793	18,646	(147)	17,149	1,497
3	Federal Unemployment Insurance	229	227	(2)	209	18
4	State Unemployment Insurance	1,174	1,165	(9)	1,071	94
5	San Francisco Payroll Tax	1,458	1,447	(11)	1,330	116
6	Total Payroll Taxes	21,654	21,485	(170)	19,759	1,726
7	Other Taxes	285	284	(1)	275	9
8	Total Taxes Other Than Income	46,464	46,287	(177)	44,529	1,758

Table 3-7
2007 General Rate Case
Plant In Service– Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
1	2004 End-of-Year Plant					
2	Functional	10,444,096	10,222,175	(221,921)	10,222,175	0
3	Common, General, and Intangible	518,857	518,857	0	518,857	0
4	Total 2004 End-of-Year Plant	10,962,952	10,741,031	(221,921)	10,741,031	0
5	2005 Full-Year Net Additions					
6	Functional	65,992	65,992	0	65,992	0
7	Common, General, and Intangible	3,800	3,800	0	3,795	5
8	Total 2005 Net Additions	69,792	69,792	0	69,787	5
9	2005 End-of-Year Plant					
10	Functional	10,510,088	10,288,167	(221,921)	10,288,167	0
11	Common, General, and Intangible	522,656	522,656	0	522,651	5
12	Total 2005 End-of-Year Plant	11,032,745	10,810,824	(221,921)	10,810,819	5
13	2006 Full-Year Net Additions					
14	Functional	(21,817)	(21,817)	0	(22,944)	1,126
15	Common, General, and Intangible	84,089	82,754	(1,335)	79,902	2,852
16	Total 2006 Net Additions	62,272	60,937	(1,335)	56,958	3,978
17	2006 End-of-Year Plant					
18	Functional	10,488,271	10,266,350	(221,921)	10,265,224	1,126
19	Common, General, and Intangible	606,746	605,410	(1,335)	602,553	2,857
20	Total 2006 End-of-Year Plant	11,095,017	10,871,760	(223,256)	10,867,777	3,983
21	2007 Full-Year Net Additions					
22	Functional	122,632	122,632	0	120,502	2,130
23	Common, General, and Intangible	72,404	72,404	0	45,399	27,005
24	Total 2007 Net Additions	195,036	195,036	0	165,901	29,135
25	2007 End-of-Year Plant					
26	Functional	10,610,903	10,388,982	(221,921)	10,385,726	3,256
27	Common, General, and Intangible	679,150	677,814	(1,335)	647,952	29,862
28	Total 2007 End-of-Year Plant	11,290,053	11,066,796	(223,256)	11,033,678	33,118

Table 3-7
2007 General Rate Case
Plant In Service– Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
29	**2007 Weighted Average Net Additions**					
30	Functional	50,115	50,115	(0)	48,784	1,331
31	Common, General, and Intangible	31,818	31,818	(0)	11,052	20,766
32	Total 2007 Weighted Average Net Additions	81,933	81,933	(0)	59,836	22,097
33	**2007 Weighted Average Plant**					
34	Functional	10,538,386	10,316,465	(221,921)	10,314,008	2,457
35	Common, General, and Intangible	638,564	637,228	(1,335)	613,606	23,623
36	Total 2007 Weighted Average Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080

Table 3-8
2007 General Rate Case
Depreciation – Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Depreciation					
1	Production	107,609	107,609	-	104,596	3,013
2	Transmission	3,467	3,374	(94)	3,467	(94)
3	Distribution	0	0	-	-	-
4	General	132	132	-	132	-
5	Subtotal	111,208	111,114	(94)	108,195	2,920
6	Common Utility Allocation	24,390	24,301	(89)	23,166	1,135
					-	
7	Total	135,599	135,416	(183)	131,361	4,055
	Depreciation Reserve					
8	Production	8,535,561	8,535,561	-	8,532,868	2,693
9	Transmission	117,350	117,256	(94)	117,350	(94)
10	Distribution	0	0	-	-	-
11	General	(993)	(993)	-	(993)	-
12	Subtotal	8,651,918	8,651,825	(94)	8,649,225	2,600
13	Common Utility Allocation	176,933	176,788	(145)	192,385	(15,597)
14	Total	8,828,851	8,828,613	(238)	8,841,610	(12,997)
	Weighted Average Depreciation Reserve					
8	Production	8,662,623	8,662,623	-	8,667,327	(4,703)
9	Transmission	115,616	115,569	(47)	115,616	(47)
10	Distribution	0	0	-	-	-
11	General	-2,733	-2,733	-	(2,733)	-
12	Subtotal	8,775,507	8,775,460	(47)	8,780,210	(4,750)
13	Common Utility Allocation	197,122	197,022	(100)	202,939	(5,917)
14	Total	8,972,629	8,972,482	(147)	8,983,149	(10,667)

Table 3-9
2007 General Rate Case
Determination of Average Amounts of Working Cash Capital Supplied by Investors
Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	Operational Cash Requirements					
1	Required Bank Balances	-	-	0	-	0
2	Special Deposits and Working Funds	58	58	(0)	58	0
3	Other Receivables	27,584	27,566	(18)	27,559	6
4	Prepayments	3,541	3,541	0	3,541	0
5	Deferred Debits, Company-Wide	(193)	(193)	0	(192)	(0)
	Less					
6	Working Cash Capital not Supplied by Investors	2,102	2,102	0	2,102	0
7	Goods Delivered to Construction Sites	823	823	0	823	0
8	Accrued Vacation	39,403	39,095	(309)	35,955	3,140
	Add					
9	Prepayment, Departmental	2,294	2,294	0	2,294	0
10	Total Operational Cash Requirement	(9,044)	(8,754)	290	(5,621)	(3,133)
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	40,582	42,174	1,592	31,207	10,967
12	Working Cash Capital Supplied by Investors	31,538	33,420	1,883	25,587	7,833

Table 3-10
2007 General Rate Case
Rate Base - Test Year 2007
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E	Settlement	Settlmt. +/- than PG&E	DRA	Settlmt. +/- than DRA
	WEIGHTED AVERAGE PLANT					
1	Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080
2	Plant Held for Future Use	0	0	0	0	0
3	Common Plant – Allocation	0	0	0	0	0
4	Common Plant Held for Future Use	0	0	0	0	0
5	Total Weighted Average Plant	11,176,950	10,953,693	(223,256)	10,927,613	26,080
	WORKING CAPITAL					
6	Material and Supplies – Fuel	831	831	0	0	831
7	Material and Supplies – Other	65,586	65,586	0	65,586	0
8	Working Cash	31,538	33,420	1,883	25,587	7,833
9	Total Working Capital	97,954	99,837	1,883	91,173	8,664
	ADJUSTMENTS FOR TAX REFORM ACT					
10	Deferred Capitalized Interest	(1,054)	(1,054)	0	(1,054)	0
11	Deferred Vacation	11,769	11,769	0	11,769	0
12	Deferred CIAC Tax Effects	0	0	0	0	0
13	Total Adjustments	10,715	10,715	0	10,715	0
	LESS DEDUCTIONS					
14	Customer Advances	0	0	0	0	0
15	Accumulated Deferred Taxes – Defense	(42,088)	(42,088)	0	(42,088)	0
16	Accumulated Deferred Taxes – Fixed Assets	333,793	333,670	(123)	332,642	1,028
17	Accumulated Deferred Taxes – Other	0	0	0	0	0
18	Deferred ITC	2,320	2,320	0	2,320	0
19	Deferred Tax – Other	0	0	0	0	0
20	Total Deductions	294,025	293,902	(123)	292,874	1,028
21	DEPRECIATION RESERVE	8,988,606	8,988,459	(147)	8,999,126	(10,667)
22	TOTAL RATE BASE	2,002,989	1,781,886	(221,104)	1,737,502	44,384

Table 4-1
2007 General Rate Case
Net Capital Additions and Capital Additions - Test Year 2007
(Thousands of Dollars)

Line No.		2007 Settlement
	Net Capital Additions (Full Year Net Additions) *See Note	
1	Electric Distribution	696,932
2	Gas Distribution	207,743
3	Generation	195,036
4	**Total Net Capital Additions**	**1,099,711**
	Capital Expenditures	
5	Electric Distribution	862,006
6	Electric General and Intangible Plant	2,192
7	Total Electric Distribution	864,198
8	Gas Distribution	205,619
9	Gas General and Intangible Plant	1,080
10	Total Gas Distribution	206,699
11	Generation	182,185
12	Generation General and Intangible Plant	52,307
13	Total Generation	234,492
14	Common	342,359
15	**Total Capital Expenditures**	**1,647,748**

Commissioner Timothy Alan Simon, concurring on 40a:

In voting to approve today's decision, I applaud the Settlement Agreement between the Division of Ratepayer Advocates (DRA) and Pacific Gas & Electric Company (PG&E) et. al [1]. I recognize that it is the result of a dedicated effort and it will provide significant benefits to consumers.

Although not part of today's decision, I also want to note my support for the ratemaking treatment The Utility Reform Network (TURN) advocated regarding customer deposits. I believe it has considerable merit. In future general rate cases I intend to pay close attention to how the CPUC's ratemaking policy in this area may impact low-income customers.

In particular, while understanding that customers of higher rate paying risk are required to indemnify that risk because their credit rating and income, I do have serious concerns about this approved practice[2]. This long held practice may be potentially predatory and arguably antiquated. As a regulatory body, we should avoid practices that penalize the poor and accordingly should review these approved practices with scrutiny. To the extent that customers are making a capital contribution through this deposit process, they should be treated on par with other sources of capital —including, but not limited to, the investment banking and commercial banking community.

However, I also believe this area of concern presents opportunities. For example, I encourage PG&E to look at this class of rate paying customers as potential participants in programs offering education and training in financial literacy and energy efficiency. This has the potential of being a mechanism that can help people come out of a cycle of poverty enabled by the practice of having to make a capital contribution as a condition precedent to receiving a necessity. Given the opportunities that modern financial technology provides, I encourage PG&E to seek innovative solutions to develop savings products for low income

[1] The Settlement Agreement Among Pacific Gas and Electric Company, Division of Ratepayer Advocates, the Modesto Irrigation District, The Merced Irrigation District, The South San Joaquin Communities Association, The Western Manufactured Housing Communities Association, The Disability Rights Advocates, The California Farm Bureau Association, Southern California Edison, The Southern California Gas Company, San Diego Gas and Electric Company, The Coalition of California Utility Employees. It is dated August 21, 2006.

[2] *See,* PG&E Electric Rule 7 - Deposits.

customers by collaterizing customer deposits and/or direct debits to savings accounts. With these opportunities in mind, I cite for example the Treasurer of San Francisco, Jose Cisneros, who has worked with financial institutions to create deposit products for low income customers to reduce dependency on predatory services like check cashing. I encourage PG&E to follow suit and turn this practice to benefit the customers they serve.

Finally, while recognizing that PG&E has already been engaged in the Commission's diversity efforts, I want to highlight my belief in the importance of PG&E's commitment to achieving greater diversity goals, as contained in an agreement in principle between the Greenlining Institute and PG&E. These goals include the area of Supplier Diversity, Management Diversity, and Philanthropy. In the Supplier Diversity area, PG&E has announced in its agreement with Greenlining a good faith attempt to meet the following goals:

- minority-contract goal of <u>20% by 2010</u> or earlier and
- aspirational goal <u>of 27% minority contracts by 2015</u>, if not better.

In connection with the area of customer deposits, I envision one area that PG&E could explore as the management of such deposits by minority-owned financial institutions. I see this agreement between The Greenling Institute and PG&E to be a critical step in improving diversity opportunities for minorities, women, and the disabled veterans entities.

<u>/s/ TIMOTHY ALAN SIMON</u>
TIMOTHY ALAN SIMON
Commissioner

San Francisco, California
March 15, 2007