BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2011. (U 39 M)	Application 09-12-020 (Filed December 21, 2009)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Pacific Gas and Electric Company.	I.10-07-027 (Filed July 29, 2010)

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY; DIVISION OF RATEPAYER ADVOCATES; THE UTILITY REFORM NETWORK; AGLET CONSUMER ALLIANCE; CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION; CALIFORNIA FARM BUREAU FEDERATION; COALITION OF CALIFORNIA UTILITY EMPLOYEES; CONSUMER FEDERATION OF CALIFORNIA; DIRECT ACCESS CUSTOMER COALITION; DISABILITY RIGHTS ADVOCATES; ENERGY PRODUCERS AND USERS COALITION; ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20; MERCED IRRIGATION DISTRICT; MODESTO IRRIGATION DISTRICT; SOUTH SAN JOAQUIN IRRIGATION DISTRICT; WESTERN POWER TRADING FORUM; AND WOMEN'S ENERGY MATTERS FOR ADOPTION OF SETTLEMENT AGREEMENT

LAURA J. TUDISCO
JONATHAN BROMSON
NICHOLAS SHER
Attorneys for Division of Ratepayer Advocates
CALIFORNIA PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-2164
Email: ljt@cpuc.ca.gov

PATRICK G. GOLDEN
CRAIG M. BUCHSBAUM
STEVEN W. FRANK
ANN H. KIM
WILLIAM V. MANHEIM
PETER P. VAN MIEGHEM
MICHELLE L. WILSON
Attorneys for Pacific Gas and Electric Company
PACIFIC GAS AND ELECTRIC COMPANY
P. O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-6976
Email: swf5@pge.com

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ADDITIONAL COUNSEL LISTED ON NEXT PAGES

ADDITIONAL COUNSEL

ROBERT FINKELSTEIN
HAYLEY GOODSON
Attorneys for THE UTILITY REFORM NETWORK
115 Sansome St., Ste. 900
San Francisco, CA 94104
Telephone: (415)929-8876
Email: hayley@turn.org

JAMES WEIL
Representative for AGLET CONSUMER ALLIANCE
P.O. Box 1916
Sebastopol, CA 95473
Telephone: (707)824-5656
Email: jweil@aglet.org

DAVID J. BYERS
Attorney for CALIFORNIA CITY-COUNTY STREETLIGHT ASSOCIATION
McCracken, Byers & Richardson, LLP
870 Mitten Rd.
Burlingame, CA 94010
Telephone: (650)697-4890
Email: dbyers@landuselaw.com

RONALD LIEBERT
Attorney for CALIFORNIA FARM BUREAU FEDERATION
2300 River Plaza Dr.
Sacramento, CA 95833
Telephone: (916)561-5500
Email: rliebert@cfbf.com

RACHAEL E. KOSS
MARC D. JOSEPH
Attorneys for COALITION OF CALIFORNIA UTILITY EMPLOYEES
601 Gateway Blvd., Ste. 1000
South San Francisco, CA 94080
Telephone: (650) 589-1660
Email: rkoss@adamsbroadwell.com; mdjoseph@adamsbroadwell.com

ALEXIS K. WODTKE
Attorney for CONSUMER FEDERATION OF CALIFORNIA
520 S. El Camino Real Ste. 340
San Mateo, CA 94402
Telephone: (650)375-7840
Email: lex@consumercal.org

DANIEL W. DOUGLASS
Attorney for DIRECT ACCESS CONSUMER COALITION
Douglass & Liddell
21700 Oxnard St., Ste. 1030
Woodland Hills, CA 91367
Telephone: (818)961-3001
Email: douglass@energyattorney.com

MELISSA W. KASNITZ
Attorney for DISABILITY RIGHTS ADVOCATES
2001 Center St. Fourth Floor
Berkeley, CA 94704-1204
Telephone: (510)665-8644
Email: pucservice@dralegal.org

NORA SHERIFF
Attorney for ENERGY PRODUCERS AND USERS COALITION
Alcantar & Kahl, LLP
33 New Montgomery St., Ste. 1850
San Francisco, CA 94105
Telephone: (415)421-4143
Email: nes@a-klaw.com

BRIAN T. CRAGG
Attorney for ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20
Goodin, MacBride, Squeri, Day & Lamprey, LLP
505 Sansome St. Ste 900
San Francisco, CA 94111
Telephone: (415)392-7900
Email: bcragg@goodinmcbride.com

ADDITIONAL COUNSEL

ANN L. TROWBRIDGE
Attorney for MERCED IRRIGATION DISTRICT
Day Carter & Murphy LLP
3620 American River Dr., Ste. 205
Sacramento, CA 95864
Telephone: (916) 570-2500 ext. 103
Email: atrowbridge@daycartermurphy.com

ANN L. TROWBRIDGE
Attorney for MODESTO IRRIGATION DISTRICT
Day Carter & Murphy LLP
3620 American River Dr., Ste. 205
Sacramento, CA 95864
Telephone: (916) 570-2500 ext. 103
Email: atrowbridge@daycartermurphy.com

EDWARD W. O'NEILL
SALLE E. YOO
VIDHYA PRABHAKARAN
Attorneys for SOUTH SAN JOAQUIN IRRIGATION DISTRICT
Davis Wright Tremaine LLP
505 Montgomery St. Ste 800
San Francisco, CA 94111
Telephone: (415)276-6564
Email: edwardoneill@dwt.com

DANIEL W. DOUGLASS
Attorney for WESTERN POWER TRADING FORUM
Douglass & Liddell
21700 Oxnard St. Ste. 1030
Woodland Hills, CA 91367
Telephone: (818)961-3001
Email: douglass@energyattorney.com

MARTIN HOMEC
Attorney for WOMEN'S ENERGY MATTERS
P.O. Box 4471
Davis, CA 95617
Telephone: (530)867-1850
Email: martinhomec@gmail.com

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PACIFIC GAS AND ELECTRIC COMPANY; DIVISION OF RATEPAYER ADVOCATES; THE UTILITY REFORM NETWORK; AGLET CONSUMER ALLIANCE; CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION; CALIFORNIA FARM BUREAU FEDERATION; COALITION OF CALIFORNIA UTILITY EMPLOYEES; CONSUMER FEDERATION OF CALIFORNIA; DIRECT ACCESS CUSTOMER COALITION; DISABILITY RIGHTS ADVOCATES; ENERGY PRODUCERS AND USERS COALITION; ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20; MERCED IRRIGATION DISTRICT; MODESTO IRRIGATION DISTRICT; SOUTH SAN JOAQUIN IRRIGATION DISTRICT; WESTERN POWER TRADING FORUM; AND WOMEN'S ENERGY MATTERS FOR ADOPTION OF SETTLEMENT AGREEMENT**

I. INTRODUCTION AND REQUEST FOR COMMISSION ACTION

Pursuant to Article 12 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E or the Applicant); the Division of Ratepayer Advocates (DRA); The Utility Reform Network (TURN); Aglet Consumer Alliance (Aglet); California City-County Street Light Association (CAL-SLA); California Farm Bureau Federation (CFBF); Coalition of California Utility Employees (CCUE); Consumer Federation of California (CFC); Direct Access Customer Coalition (DACC);

Disability Rights Advocates (DisabRA);[1/] Energy Producers and Users Coalition (EPUC); Engineers and Scientists of California, Local 20 (ESC); Merced Irrigation District (Merced ID);[2/] Modesto Irrigation District (Modesto ID);[3/] South San Joaquin Irrigation District (SSJID); Western Power Trading Forum (WPTF); and Women's Energy Matters (WEM) (collectively, the "Settling Parties") hereby request that the Commission approve the Settlement Agreement (the "Agreement"), which is included as Attachment A to this Motion, as a compromise among their respective litigation positions to resolve all disputed issues raised by parties in the above-referenced proceeding, with the exception of one issue set forth in Section 3.9(d) of the Agreement related to whether PG&E should earn its authorized rate of return on its undepreciated investment in electric and gas meters replaced by SmartMeter devices, which shall be separately briefed by the parties. Unless otherwise provided in the Agreement, all proposals and recommendations by the parties, including, but not limited to, those set forth in the Joint Comparison Exhibit (PG&E-69), are either withdrawn or considered subsumed without adoption by the Agreement.

The Settling Parties request that the Commission issue a final decision approving the Agreement and resolving the issue raised in the separate briefs as expeditiously as possible.[4/]

1/ DisabRA joins only in the following portions of the Settlement Agreement: Article 1, Article 2, Article 3.12(j), and Article 4.

2/ Merced ID joins only in the following portions of the Settlement Agreement: Article 1, Article 2, Article 3.5.1(b), and Article 4.

3/ Modesto ID joins only in the following portions of the Settlement Agreement: Article 1, Article 2, Article 3.5.1(b), and Article 4.

4/ CPUC Rule 12.1(a) provides that parties may propose settlements for adoption within 30 days after the last day of hearings. Evidentiary hearings were completed on July 22, 2010, and on August 4, 2010, PG&E, DRA, TURN and Aglet advised Administrative Law Judge Fukutome and all parties that they were currently engaged in settlement discussions, which led to a variety of rulings postponing the procedural schedule for the matter. To the extent that Rule 12.1(a) pertains to the matter at hand, the Settling Parties ask that the 30-day limit be extended or waived. The Settling Parties have devoted substantial time and

The Settling Parties also request that the Commission find that PG&E is financially healthy, and that the Agreement will provide PG&E with revenues that will be sufficient for PG&E to provide safe, reliable service and to make necessary capital investments.[5/]

This Motion is organized as follows. Section II describes the many interests represented by the 17 Settling Parties. Section III provides a Procedural History of this matter. Section IV summarizes the litigation positions taken by the Settling Parties. Section V summarizes the Agreement. Section VI explains why the Agreement is reasonable, consistent with law, and in the public interest as required by CPUC Rule 12.1(d). Section VII provides a brief conclusion.

As mentioned above, Attachment 1 to this Motion includes the Agreement. As required by CPUC Rule 12.1(a), Attachment 2 to this Motion is a Comparison Exhibit indicating the effect of the Agreement in relation to PG&E's showing and to issues that DRA contested in this proceeding.

II. INTEREST OF SETTLING PARTIES

The Settling Parties represent the interests of the Applicant and a variety of other interests. For example, DRA, TURN, Aglet, CFC, and others represent wide-spread interests of consumers of gas and electricity, including low-income consumers. CAL-SLA represents the interests of street light customers. CCUE represents the interests of represented utility

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effort to achieving this Agreement. Furthermore, because the Agreement leaves only one issue unresolved, its consideration and adoption will promote the "just, speedy, and inexpensive determination of the issues presented." (Rule 1.2.)

5/ In PG&E's test year 2007 GRC, the Commission adopted a settlement agreement that resolved most contested issues, concluding that PG&E would not have settled if that agreement would harm PG&E's financial health. (D.07-03-044, *mimeo*, pp. 250-251.) Based on the evidentiary record in that proceeding, the Commission explicitly found that PG&E was financially healthy, and that the adopted settlement would provide PG&E with sufficient revenues to maintain its financial health, provide adequate service, and make necessary capital investments. (D.07-03-044, Findings of Fact 29 and 30, p. 275.) The record in the current proceeding provides ample evidence to support corresponding findings. (Ex. Aglet-3, pp. 8 to 13, and supporting documents in Exhibits Aglet-5 and Aglet-6; Tr. Vol. 21, 2589:17 to 2590:3, PG&E/Malnight.)

employees at PG&E and most electric utilities in California. CFBF represents the interests of agricultural customers. DACC represents the interests of direct access customers. DisabRA represents the interests of the disabled. EPUC represents the interests of larger industrial customers. ESC represents the interests of the engineers, scientists, and other professionals and technical employees of PG&E. Merced ID, Modesto ID, and SSJID represent the interests of irrigation districts. WPTF represents the interests of its membership in encouraging competition in Western states electric markets. Finally, WEM represents women and men working for a rapid transition to an efficient, renewable energy system.

Of the 127 witnesses who submitted testimony in this proceeding, all but three were sponsored by the Settling Parties.

III. PROCEDURAL HISTORY

On December 21, 2009, PG&E filed its 2011 GRC Application. On February 19, 2010, the Commission convened a prehearing conference before Administrative Law Judge (ALJ) David Fukutome.

On March 5, 2010, Assigned Commissioner Michael P. Peevey issued an "Assigned Commissioner's Ruling and Scoping Memo" (ACR) setting the procedural schedule, assigning ALJ Fukutome as the Presiding Officer, and addressing the scope of the proceeding and other procedural matters.

On May 5, 2010, DRA served its testimony in response to PG&E's 2011 GRC Application and supporting testimony.

On May 19, 2010, TURN, Aglet, CAL-SLA, CCUE, CFBF, DACC, EPUC, ESC, the Greenlining Institute (Greenlining), Merced ID, Modesto ID, SSJID, and WPTF served their testimony. On May 20, 2010, CFC served its testimony, and on May 26, 2010, WEM served its testimony. Also on May 26, 2010, DisabRA and PG&E submitted joint testimony concerning certain accessibility issues.

On June 4, 2010, PG&E served its rebuttal testimony to DRA's and intervenors' testimony. Also on June 4, 2010, EPUC, SSJID, and WEM served reply testimony, and CCUE, Greenlining, and Southern California Edison (SCE) served rebuttal testimony.

Evidentiary hearings began on June 21, 2010 and continued through July 16, 2010 with one final witness appearing on July 22, 2010. The record remained opened for update hearings then scheduled for October 6 and 7, 2010.

On July 30, 2010, PG&E served the Joint Comparison Exhibit (Exhibit PG&E-69) that provided a detailed comparison of the revenue requirement positions of PG&E and DRA, and included (as Appendix H thereto) descriptions of various intervenors' positions.

In late July and continuing during the months thereafter, parties engaged in settlement discussions. These discussions led to various extensions of the procedural schedule for this GRC, including the schedule for update hearings.

On August 5, 2010, the Commission issued an order instituting investigation (OII) on the Commission's own motion into the rates, operations, practices, service, and facilities of PG&E. The OII is dated July 29, 2010.

On August 6, 2010, PG&E filed a motion requesting an order making its new revenue requirements effective January 1, 2011, even though the Commission may not issue a final decision on its 2011 GRC request until sometime after that date. DRA, TURN, and Aglet authorized PG&E to state that they did not oppose the relief requested.

On October 7, 2010, pursuant to CPUC Rule 12.1(b), PG&E notified all parties on the service list of a settlement conference to be held on October 15, 2010 to discuss the terms of the Agreement. Following the settlement conference, the Settling Parties executed this Agreement.

IV. SUMMARY OF SETTLING PARTIES' LITIGATION POSITIONS

The following subsections summarize the various Settling Parties' litigation positions. Additional detail regarding the Settling Parties' positions can be found in Section VI of this Motion, which discusses the reasonableness of the Agreement.

A. PG&E's Position

At the end of hearings, and as reflected in Exhibit PG&E-69 (Joint Comparison Exhibit), PG&E's litigation position would result in base revenue requirements of $3,534 million for electric distribution, $1,293 million for gas distribution, and $1,820 million for electric generation, resulting in increases over currently authorized revenues of $527 million for electric distribution, $208 million for gas distribution, and $329 million for electric generation.[6/] In addition, adoption of PG&E's litigation position would result in attrition increases of $181 million in 2012 and $223 million in 2013 for electric distribution, $49 million in 2012 and $64 million in 2013 for gas distribution, and $33 million in 2012 and $47 million in 2013 for electric generation.[7/]

B. DRA's Position

At the end of hearings, and as reflected in the Joint Comparison Exhibit, DRA's litigation position recommended a total 2011 revenue requirement of $3,151 million for electric

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6/ Ex. PG&E-69, p. 1-5.

7/ Ex. PG&E-69, p. F-1. These amounts, and all other amounts in this Agreement, are in nominal Federal Energy Regulatory Commission (FERC) dollars unless noted otherwise. Where amounts are listed as "Fully Burdened dollars," these amounts include payroll taxes and employee benefit burdens.

distribution, $1,072 million for gas distribution, and $1,540 million for electric generation, resulting in an increase of $144 million, a decrease of $12 million, and an increase of $49 million, respectively, over currently authorized electric and gas distribution and generation-related revenues.

Regarding attrition, adoption of DRA's litigation position would permit PG&E to file an advice letter seeking attrition relief that DRA estimated would result in increases of $63 million and $58 million for electric distribution in 2012 and 2013, respectively; $21 million and $20 million for gas distribution in 2012 and 2013, respectively; and $31 million and $28 million for electric generation in 2012 and 2013, respectively.

DRA's litigation position reflects significant decreases to PG&E's forecast Administrative and General (A&G) expenses; electric and gas distribution Operations and Maintenance (O&M) expenses; electric generation expenses; Customer Accounts expenses; Information Technology (IT) and other Shared Services costs; income tax expenses; electric, gas, and common plant; depreciation; and rate base; as well as increases to Other Operating Revenues.

C. TURN's Position

TURN made a number of recommendations, including reducing overall A&G spending, rejecting ratepayer funding of the Short Term Incentive Plan (STIP), reducing Customer Care costs, excluding SmartMeter costs from the GRC, reducing electric and gas distribution capital and expense items, reducing electric generation capital and expense items and adopting policies to limit capital spending to new hydro projects that are cost-effective, suspending accrual of Allowance for Funds Used During Construction (AFUDC) for ten Business Transformation software projects (called "Transform Operations"), reducing depreciation and rate base for numerous items, reducing electric and gas revenue requirements and various tax expenses for specific tax adjustments, rejecting or reducing funding for numerous real estate projects and activities, requiring PG&E to move toward vehicle leasing rather than ownership, writing off gross plant for the IT Business Transformation Foundational Project, reducing overall IT spending, rejecting certain political costs, reducing supply chain capital and expenses, and adopting DRA's proposed forecast for electric emergency recovery.[8/]

D. Aglet's Position

Aglet made several proposals, including generally contesting PG&E's policy arguments regarding industry leadership, customer satisfaction, financial health, and economic impact of capital spending; reducing PG&E's Reserve Fund and Efficiency Fund; reducing PG&E's Customer Care expenses to reflect SmartMeter benefits; recommending that all SmartMeter costs be removed from the GRC, and recommending that PG&E file an application for review of the reasonableness of all SmartMeter costs; adopting an uncollectibles factor of 0.2853%; denying PG&E's entire request for customer retention and economic development activities; reducing PG&E's request and ordering specific compliance items for Diablo Canyon Power Plant expense and capital items; ordering that total factor productivity studies should no longer be required; recommending that labor productivity factors be incorporated into PG&E's 2011 revenue requirements calculation; rejecting PG&E's requests for new balancing accounts; reducing PG&E's requested attrition adjustments for 2012 and 2013; finding that Z-factor protection should be limited to five specific costs; and reducing PG&E's IT request and recommending an investigation into PG&E's procurement of IT products and services.[9/]

8/ Ex. PG&E-69, pp. H-23 to H-46.

9/ Ex. PG&E-69, pp. H-2 to H-5.

E. CAL-SLA's Position

CAL-SLA recommended that the Commission not approve PG&E's proposed streetlight light emitting diode (LED) conversion program; and that the Commission reduce PG&E's request for streetlight rate base, O&M expenses, and expenses for burnouts and group replacements.[10/]

F. CFBF's Position

CFBF generally supported DRA's recommendations but proposed to increase DRA's distribution maintenance expense recommendation by $71 million.[11/]

G. CCUE's Position

CCUE recommended that PG&E should be authorized and required to do more pole replacement work than PG&E requested funding for, be required to do all gas leak survey and repair work needed even if it is more work than PG&E sought funding for, attain and maintain staffing levels sufficient to perform all needed gas work, hire a steady flow of new apprentices for electric distribution work and maintain an apprentice:journeyman ratio of 1:2, be required to achieve the goals of the 2008 Equipment Requiring Repair Report and to work off the equipment requiring repair backlog by the end of 2011, and be required to reduce the backlog of items tagged out of compliance with CPUC regulations. CCUE proposed enforcement mechanisms, such as balancing accounts and contempt proceedings, to ensure PG&E performed this work. CCUE also recommended that the CPUC not rely on the Total Compensation Study.[12/]

10/ Ex. PG&E-69, p. H-6.

11/ Ex. PG&E-69, p. H-7.

12/ Ex. PG&E-69, p. H-11.

H. CFC's Position

CFC recommended that PG&E should postpone charging costs of new programs that are not essential or not well-developed; should use a different base year than 2008; should not receive funding for Distribution and Integrity Management Program (DIMP), Technical Training, or LED streetlight replacement; should be required to use a standard forecasting model to predict future costs; should reduce labor escalation and attrition adjustments; should quantify cost savings for various programs; should be required to use FERC accounts to record costs; should not be permitted to have balancing accounts for Rule 20A, major emergencies, healthcare, research development and demonstration (RD&D), renewable generation, or uncollectible accounts expense; should not contribute to the revitalization of the California economy; should not monopolize the provision of recharging or filling stations; should have its SmartMeter and SmartGrid funding reduced; should be audited regarding its Proposition 16 spending; and should not receive funding for RD&D or the transfer of PG&E Corporation employees to the Utility.[13/]

I. DACC's Position

DACC recommended that electric RD&D generation project costs be tracked separately from distribution and that results of PG&E's electric RD&D be placed in the public domain. DACC also supported the conditional adoption of PG&E's proposal for revised Direct Access (DA) fees, subject to review in a future proceeding.[14/]

J. DisabRA's Position

In lieu of providing independent testimony in the GRC, DisabRA negotiated a Memorandum of Understanding with PG&E regarding improved access: to PG&E's local offices

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13/ Ex. PG&E-69, pp. H-12 to H-16.

14/ Ex. DACC-1.

and pay stations, around construction sites and pole locations, and to PG&E's communications materials (including written communications, telecommunications, communications with medical baseline customers, and bill design) and website. It also sets forth procedural requirements including reporting and a dispute resolution process. On May 26, 2010, DisabRA and PG&E jointly submitted this MOU as part of Exhibit PG&E-16.

K. EPUC's Position

EPUC recommended that the Commission reduce PG&E's proposed hydroelectric capital expenditures; retain the current authorization for recovery of carrying costs of nuclear fuel inventory and reject PG&E's proposal to include $378 million in rate base; and reject PG&E's requests for a 1% increase in rate of return for decommissioning Kilarc-Cow, to recover abandonment costs, and to hold Tesla in Plant Held for Future Use (PHFU).[15/]

L. ESC's Position

ESC recommended that all typical technical and professional work be performed by PG&E employees, not contractors, with certain exceptions; that PG&E monitor and evaluate the performance of contracts and report to the Commission; and that PG&E work with its employee unions to develop a workforce plan to address projected workload, employee attrition, and knowledge transfer.[16/]

M. Merced ID and Modesto ID Positions

Merced ID and Modesto ID recommended that the Commission deny PG&E's entire request for customer retention activities; require PG&E to reimburse ratepayers for amounts spent on customer retention activities from 2007 to 2011; enjoin PG&E from spending further

15/ Ex. PG&E-69, p. H-17.

16/ Ex. PG&E-69, p. H-18.

ratepayer funds on customer retention activities; and require PG&E to equitably allocate expenses for distribution projects among distribution planning areas.[17/]

N. SSJID's Position

SSJID recommended that the Commission maintain PG&E's distribution capital expenditures at 2008 levels; disallow 54.375% of PG&E's STIP funding, set up a one-way balancing account, reduce the STIP payout to 50% of the maximum potential payout, and redesign STIP targets; disallow all holding company costs; examine PG&E's below-the-line (BTL) guidelines and reduce funding for departments that engage in BTL activities; deny funding for customer retention activities; disallow any RD&D funding; disregard PG&E's claims regarding economic stimulus; and change the ratemaking treatment of PG&E's income tax expense for this and future PG&E GRCs.[18/]

O. WPTF's Position

WPTF recommended rejection of PG&E's request for recovery of costs associated with the Tesla Power Plant and PG&E's request for recovery of up to $27 million in renewable energy development costs in a one-way balancing account.[19/]

P. WEM's Position

WEM recommended reductions to electric distribution, Customer Care, SmartMeter, Energy Supply, and A&G funding; proposed enhanced procedures and an audit for BTL

17/ Ex. PG&E-69, p. H-19.

18/ Ex. PG&E-69, pp. H-20 to H-21.

19/ Ex. WPTF-1, p. 2.

activities; and recommended imposing automatic penalties if PG&E continues to fund customer retention and economic development activities.[20]

V. SUMMARY OF SETTLEMENT AGREEMENT

Articles 1 and 2 of the Agreement provide a brief introduction to the Agreement and set forth its Procedural History. Article 3 of the Agreement provides that, using a starting point of PG&E's requested increase of $1,064 million,[21] the Commission should allow a test year 2011 revenue requirement increase of $395 million, which is generally constructed using the other terms set forth therein. Article 4 of the Agreement sets forth General Provisions and Reservations.

The following subsections summarize the main provisions of Articles 3 and 4.

A. Article 3 – Settlement of Issues

1. Overall Test Year Revenue Requirement

Section 3.1 of the Agreement provides for a 2011 revenue requirement increase of $395 million as compared to PG&E's requested increase of $1,064 million. The increases are $183 million for electric distribution, $47 million for gas distribution, and $166 million for electric generation.[22] (The revenue requirements for the 2012 and 2013 attrition years are addressed in Section 3.11 of the Agreement.)

2. Electric Distribution

Section 3.2.1 of the Agreement reduces PG&E's electric distribution expense and capital revenue requirement request by at least $52 million, including $8 million expense for New

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20/ Ex. PG&E-69, pp. H-47 to H-51.

21/ Ex. PG&E-69, p. 1-5, Table 1-1.

22/ The $1 million difference is due to rounding.

Business and Work at the Request of Others (WRO); $18.5 million expense for vegetation management; and $2 million in capital-related revenue requirement for the LED Streetlight Replacement Project.

Section 3.2.2 addresses the following non-revenue requirement-specific issues:

- Section 3.2.2(a) addresses the structure of, and spending level for, PG&E's Vegetation Management Balancing Account (VMBA).
- Section 3.2.2(b) revises the manner of allocation of work credits for Rule 20A projects, providing special consideration for communities with projects already in progress.
- Section 3.2.2(c) provides an allocation - between generation and distribution - for the electric RD&D project costs proposed in PG&E's testimony. This section also provides that, subject to certain limitations, the results of such projects shall be placed in the public domain.

3. Gas Distribution

Section 3.3.1 of the Agreement reduces PG&E's gas distribution expense request by at least $30 million, consisting in part of reductions to Major Work Category (MWC) EX to reflect DRA's position on the gas meter protection program, and reductions to MWC DG to reflect DRA's and TURN's positions on cathodic protection of isolated services. Section 3.3.1 also explains that the agreed-upon revenue requirement reflects maintenance of currently mandated levels of gas leak inspection work, and that all gas distribution operations and maintenance work will be performed at currently mandated levels.

Section 3.3.2 provides for a one-way balancing account mechanism for PG&E's DIMP, setting a cap for the balancing account of $60 million for DIMP costs for the term of this GRC cycle (2011-2013). Any net unspent DIMP funds at the end of this GRC cycle would be returned to customers in the next GRC.

4. Energy Supply

Section 3.4.1 of the Agreement reduces PG&E's Energy Supply O&M expense and capital-related revenue requirement request by at least $42 million, including:

- no approval in this GRC of new small hydroelectric generation plants installed after test year 2011;
- a $1.6 million reduction related to Tesla Power Plant cancellation expense and a $3.5 million reduction related to Tesla Power Plant PHFU;
- removal of capital costs of the Britton powerhouse from this test year 2011 rate case cycle;
- removal from this GRC of the revenue requirement for Renewable Resource Development (RRD);
- an $8 million reduction for energy procurement;
- removal of PG&E's requested rate of return adder on the Kilarc-Cow decommissioning project;
- a reduction of $2 million to reflect reductions in hydroelectric generation capital expenditures;
- limiting rate recovery of Nuclear Energy Institute (NEI) fees to 50% of forecast cost; and
- allowing only one long-term service agreement (LTSA) payment collected through normalized funding per plant.

In addition to the revenue requirement-specific issues summarized above, the Agreement also resolves the following issues:

- Section 3.4.2(a) provides that PG&E shall treat Diablo Canyon Power Plant labor costs associated with nuclear fuel removal, drying, loading, and encapsulation as operating expense, not capital expenditures.
- Section 3.4.2(b) provides that PG&E's Diablo Canyon Steam Generator Replacement Project costs will be recovered in generation rates without the need for further reasonableness review.
- Section 3.4.2(c) provides that PG&E will be allowed to transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account (UGBA) when the total costs of the project are known, and close out the Gateway balancing account at that time.
- Sections 3.4.2(d) and (e) provide that PG&E is authorized to file an advice letter to true-up the Colusa Generating Station (CGS or Colusa) project's initial capital cost, as well as the initial capital costs of the Humboldt Bay Generating Station (HBGS or Humboldt Bay) subject to the requirements of Decision (D.) 06-11-048, when the final project costs are known.
- Section 3.4.2(f) allows PG&E to increase the initial capital cost target approved for the HBGS project by up to $25 million by advice letter, as opposed to an application, to the extent the project's actual costs exceed the initial cost target.
- Section 3.4.2(g) affirms PG&E's prior commitment to remediate the Hunters Point Power Plant site to residential standards, consistent with the direction of regulators.

- Section 3.4.2(h) provides that PG&E will provide a status report in the next GRC on spent nuclear fuel payments and other related issues.

5. Customer Care Expenses

Section 3.5.1 of the Agreement reduces PG&E's Customer Care revenue requirement request by at least $137 million, including removal of $113 million (Fully Burdened dollars) of forecast meter reading costs, $10 million of peak day pricing expense, and $14 million for other issues. This latter amount includes a reduction of $7 million for customer retention and economic development programs. In conjunction with this revenue requirement adjustment, Section 3.5.1(a) removes meter reading costs from the GRC and directs PG&E to record actual meter reading costs in a new balancing account. Section 3.5.1(b) also requires PG&E to book the customer retention costs below-the-line.

In addition to the revenue requirement-specific issues summarized above, the Agreement resolves the following non-revenue requirement-specific issues:

- Section 3.5.2(a) denies PG&E's proposal for a new balancing account mechanism for uncollectibles and provides that PG&E's uncollectibles factor shall be 0.3105% for the 2011-2013 GRC cycle.
- Section 3.5.2(b) provides that the Commission's Energy Division will oversee an independent audit of PG&E SmartMeter-related costs, at PG&E's expense, to determine whether costs that should have been recorded in the SmartMeter balancing accounts were instead recorded in other accounts, for example, accounts related to the GRC, demand response, or dynamic pricing programs.
- Section 3.5.2(c) of the Agreement provides that the SmartMeter Benefits Realization Mechanism adopted by the Commission in D.06-07-027 and

D.09-03-026 should be continued through the 2011 rate case cycle. This section also provides for adjustments to the per-meter amounts returned to customers through the mechanism.

- Section 3.5.2(d) provides that the CPUC's consultant costs for the recently-completed SmartMeter evaluation shall be eligible for recovery through the SmartMeter balancing accounts.
- Section 3.5.2(e) provides that DA and Community Choice Aggregation (CCA) fees should be adopted as proposed. PG&E commits to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA fees. This section also allows PG&E to cease recording costs to the Direct Access Discretionary Cost/Revenue Memorandum Account (DADCRMA), pending review of the account in the upcoming application.
- Section 3.5.2(f) provides that PG&E's reconnection fees shall not be revised and shall remain at existing levels.
- Section 3.5.2(g) provides that PG&E's proposal to adjust local office hours (to have all offices open from 8:30 a.m. to 5:00 p.m.) shall be adopted.
- Section 3.5.2(h) provides that PG&E's proposed expansion of Non-Tariffed Products and Services (NTP&S) should be adopted, but PG&E's proposals concerning the 50/50 net revenue sharing mechanism and a sharing mechanism for shareholder capital should not be adopted.
- Section 3.5.2(i) provides that PG&E's non-sufficient funds (NSF) fee should be reduced to $9 from its current level of $11.50.

6. Administrative and General (A&G)

Section 3.6.1 of the Agreement reduces PG&E's A&G annual revenue requirement request by at least $89 million, consisting in part of: (i) $45 million to reflect parties' arguments regarding STIP; (ii) $11.4 million to reflect parties' arguments with respect to the following departments: (1) Public Affairs (includes $2.5 million reduction); (2) Corporate Relations (includes $2.5 million reduction); and (3) PG&E Corporation (Corporate Services and holding company corporate items; includes $6.4 million reduction); and (iii) $1.9 million to reflect 50/50 sharing of Directors and Officers liability insurance.

In addition to the revenue requirement-specific issues summarized above, the Agreement resolves the following non-revenue requirement-specific issues:

- Section 3.6.2(a) provides that the estimate of total contributions for 2011 to the post-retirement benefits other than pensions (PBOPs) medical and life, and long-term disability (LTD) trusts will be $163.3 million (total company before allocation to capital and other non-GRC unbundled cost categories (UCCs), which will also apply to the attrition years.
- Section 3.6.2(b) provides that the factors used to calculate franchise fees will be 0.007593 (electric) and 0.009789 (gas).
- Section 3.6.2(c) provides that PG&E shall modify its current Below-the-Line Guidelines to provide for (1) greater reporting detail and an annual compliance review, (2) expanded applicability for certain PG&E activities in response to municipalization and CCA activities, (3) annual e-mails to all employees regarding their obligation to comply with the guidelines, (4) annual training on

the guidelines for certain departments and (5) extended applicability of the guidelines to PG&E Corporation employees.

- Section 3.6.2(d) restricts PG&E's ability to accept transfers of employees from an affiliate unless certain conditions are met.
- Section 3.6.2(e) requires PG&E to keep additional records of the business reasons for meals, including information on attendees.

7. Shared Services

Section 3.7 of the Agreement reduces PG&E's Shared Services' revenue requirement request by at least $55 million (with an additional $4.6 million reflected in A&G above), including at least $50 million for IT costs to resolve DRA and intervenor issues, including TURN's arguments about Business Transformation "Foundational" programs. Sections 3.7(b) and (c) of the Agreement exclude any costs of sale of PG&E's building at 111 Almaden, San Jose (111 Almaden) or relocation, severance, and retraining costs arising from that sale, and reduce PG&E's fleet request by $4 million for capital-related revenue requirements to account for the California Air Resources Board's approval of an alternative compliance plan for meeting existing California diesel fleet regulations.

8. Depreciation

Section 3.8 of the Agreement reduces PG&E's depreciation revenue requirement by no more than $105 million, as well as $2.5 million of generation decommissioning costs, which comprises $2 million for the Old Humboldt fossil plant and $0.5 million for Gateway, Colusa, and New Humboldt.

9. Capital-Related Costs, Including Rate Base And Method For Income Taxes

Section 3.9 of the Agreement addresses the following capital-related costs:

- Section 3.9(a) provides for a \$35 million reduction to reflect (1) capital expenditure reduction for New Business/WRO; (2) recalculation of 2011 rate base using updated estimates of bonus depreciation-related deferred tax balances; and (3) resolution of issues raised by TURN regarding income taxes, customer deposits, and materials and supplies.
- Section 3.9(b) provides that PG&E shall withdraw its proposal to include nuclear fuel and fuel oil inventory in rate base, reducing revenue requirement by \$49 million associated with nuclear fuel, plus additional dollars associated with fuel oil. This section also provides that nuclear fuel and fuel oil carrying costs will continue to be recovered through the Energy Resource Recovery Account (ERRA) at short-term commercial paper rates.
- Section 3.9(c) provides that PG&E will remove all Market Redesign and Technology Upgrade (MRTU) related revenue requirements totaling \$20 million in 2011, seeking such costs in ERRA proceedings or other proceedings if so directed by the Commission.
- Section 3.9(d) provides for a reduction of \$44 million (revenue requirement) to reflect TURN's position to allow no rate of return on undepreciated electric and gas meters replaced by SmartMeter devices. This section provides that the parties will brief the dispute for the Commission's decision in this proceeding and, if PG&E prevails on the issue, the test year revenue requirement will be increased accordingly.
- Section 3.9(e) provides a table of 2011 rate base and capital expenditure levels for the electric distribution, gas distribution, and energy supply areas of business.

10. Balancing Accounts

Section 3.10 of the Agreement provides that PG&E shall have no new balancing accounts for health care costs; New Business/WRO/Rule 20A; renewable energy projects; uncollectibles; emergencies and catastrophic events; or RD&D expenses. This section further provides that PG&E shall continue current electric and gas sales mechanism balancing accounts (DRAM, UGBA, CFCA, and NCA) through 2013.

11. Attrition Years

Section 3.11.1 of the Agreement provides that attrition relief for 2012 and 2013 will be authorized in this GRC, and implemented by advice letter. Section 3.11.2 provides that PG&E's annual distribution attrition adjustment for 2012 and 2013 will be fixed dollar amounts of $180 million in 2012, and $185 million in 2013. Section 3.11.3 provides that PG&E's attrition mechanism will reflect exogenous changes, limited to five factors (postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, *ad valorem* tax changes), with a $10 million deductible amount applied to each factor each year.

12. Accounting and Other Issues

Section 3.12 of the Agreement resolves the following additional accounting and other issues:

- Section 3.12(a) adopts PG&E's forecasts of adopted gas and electric revenues at present rates.
- Section 3.12(b) provides that the CPUC-jurisdictional Other Operating Revenues (OOR) shall be $97.9 million for electric distribution, $22.9 million for gas distribution, and $11.6 million for electric generation.

- Section 3.12(c) provides that the resulting revenue requirements from future cost of capital proceedings shall be calculated using the adopted 2011 rate base amounts.
- Section 3.12(d) provides the following capitalization rates: 24.65 percent for STIP; 38.41 percent for Severance, Workers' Compensation, Remaining Vacation, and Pension and Benefits; and 9.3 percent for Third Party Claims payments.
- Section 3.12(e) provides that the revenue requirement adopted by this Agreement incorporates a change in the threshold (from $5 million to $1 million) after which PG&E capitalizes the development of application software.
- Section 3.12(f) adopts capitalization factors for A&G Study departments of 7.33 percent for labor and 4.44 percent for materials.
- Section 3.12(g) adopts allocation factors associated with non-utility activities for PG&E Corporation corporate items of 32.68%, below the line for workers' compensation and benefits of 0.31%, and non-utility affiliates for benefits of 0.06%.
- Section 3.12(h) provides that for common cost (A&G and common plant) allocation factors, the O&M labor factors will be calculated from 2008 recorded adjusted O&M labor.
- Section 3.12(i) provides that A&G expenses allocated to the UCCs adopted in this 2011 GRC shall be used in determining the A&G expenses in related proceedings in 2011 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.

- Section 3.12(j) provides that the Memorandum of Understanding (MOU) between DisabRA and PG&E set forth in Exhibit PG&E-16 shall be approved by the Commission.
- Section 3.12(k) provides that Aglet's proposal to eliminate the requirement in D.86-12-095 that requires PG&E to prepare total factor productivity studies shall be adopted.
- Section 3.12(l) provides that PG&E shall be relieved of the requirement in D.04-05-055 (p. 108) to include information about long-term incentives, which are not funded by ratepayers, in future total compensation studies.
- Section 3.12(m) provides for certain steps for PG&E and DRA to take in the preparation of PG&E's next GRC to improve PG&E's Results of Operation (RO) model.
- Section 3.12(n) provides that in future GRCs, PG&E will not add a new type of cost to the revenue requirement without addressing the cost savings to be achieved by the new type of cost.
- Section 3.12(o) provides that PG&E shall affirmatively establish the reasonableness of all aspects of its next GRC application. This section further provides that for purposes of the current GRC, opinion testimony should have a factual foundation.
- Section 3.12(p) provides that PG&E shall suspend AFUDC accruals for ten Business Transformation projects called "Transform Operations" identified by TURN and that PG&E shall ensure that future requests for capital recovery of the

projects do not include AFUDC for the periods starting with certain dates identified in TURN's testimony.

- Section 3.12(q) withdraws PG&E's testimony on the economic impacts of its capital spending during the test year 2011 GRC cycle.
- Section 3.12(r) withdraws various Aglet recommendations and proposals concerning Reserve and Efficiency Funds; sunk benefits in future Diablo Canyon cost benefit studies; treatment of Diablo Canyon critical spares as PHFU; labor productivity factors; and PG&E's procurement of IT products and services.
- Section 3.12(s) provides that ESC and PG&E have resolved certain issues associated with outsourcing and that in PG&E's next GRC, PG&E will submit testimony on the status of its workforce training programs, its hiring in advance of employee attrition at Diablo Canyon Power Plant, and its request for additional hydroelectric department resources.
- Section 3.12(t) provides that PG&E and CCUE have decided to address CCUE's issues through a separate agreement as part of the collective bargaining process. As a result, CCUE is withdrawing its recommendations in this case without prejudice to making such recommendations in other proceedings.

B. Article 4 – General Provisions and Reservations

Article 4 includes many general provisions and reservations common to these types of settlements. Indeed, most of these provisions and reservations can be found in the settlement of PG&E's 2003 GRC, approved by the Commission in D.04-05-055. For example, Section 4.5 of the Agreement, which also appeared in the 2003 settlement agreement, states: "This Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations or understandings among the Settling Parties."[23/]

Unlike most of the other provisions in Article 4, the following provisions have substantive content specific to the matter at hand:

- Section 4.1 explains that the Agreement represents a compromise among the Settling Parties' respective litigation positions to resolve all disputed issues raised by parties in the above-referenced proceeding, with the exception of the issue related to TURN's position to allow no rate of return on undepreciated electric and gas meters replaced by SmartMeter devices, which shall be separately briefed by the parties.[24/]
- Section 4.11 states that the fact that 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 in a manner consistent with its obligation to provide reliable service and consistent with its obligation to maintain the safe operation of its utility systems. This section further provides that the Agreement does not limit the discretion of other parties to argue in future proceedings that it is unjust or unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in this proceeding or that PG&E has not provided safe and reliable service.

23/ This provision appeared as Reservation 5, on page 21 of the settlement agreement approved in D.04-05-055.

24/ The Agreement does not resolve the separate complaint filed by Merced ID and Modesto ID, which is being considered in a separate docket.

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- Section 4.13 provides that unless otherwise provided in the Agreement, all proposals and recommendations by the parties, including, but not limited to, those set forth in the Joint Comparison Exhibit,[25/] are either withdrawn or considered subsumed without adoption by the Agreement.

VI. THE COMMISSION SHOULD APPROVE THE AGREEMENT AS REASONABLE IN LIGHT OF THE WHOLE RECORD, CONSISTENT WITH LAW AND IN THE PUBLIC INTEREST.

A. Legal Standard for Settlements

Commission Rule 12.1(d) sets for the standard for approval of settlements:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

The Commission approves settlement agreements based on whether the settlement agreement is just and reasonable as a whole, not based on its individual terms:

> In assessing settlements we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on whether any single provision is the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.[26/]

As noted above, the Commission strongly favors settlement:

> The Commission also takes into consideration a long-standing policy favoring settlements. This policy reduces litigation expenses, conserves scarce Commission resources and allows parties to craft their own solutions reducing the risk of unacceptable outcomes if litigated.[27/]

25/ Ex. PG&E-69.

26/ D.10-04-033, *mimeo*, p. 9.

27/ D.10-06-038, *mimeo*, p. 36.

The Commission's general policy supporting settlements was reiterated in the context of the current proceeding. At the February 19, 2010 Prehearing Conference, ALJ Fukutome stated:

> [I]n general, the Commission has a policy of supporting the resolution of disputed matters through settlement. … [S]ettlements can reduce the time and expense of litigation, can conserve Commission resources, and allows parties to reduce the risks associated with litigation. And from my perspective, settlements are desirable. Even if the settlement is contested or if it's only a partial settlement, the number of issues and the extent that certain issues need to be addressed in the decision is narrowed.[28/]

The March 5, 2010 ACR reaffirmed this view and stated, "Parties are encouraged to settle as many issues as possible."[29/]

B. The Settlement Agreement Meets The Legal Standard For Settlements.

As previously described, the legal standard for Commission approval of settlements is that the settlement must be "reasonable in light of the whole record, consistent with law, and in the public interest."[30/] The Settling Parties are aware of no statutory provision or controlling law that would be contravened or compromised by the Agreement. In the following subsections, the Settling Parties demonstrate that the Agreement is reasonable in light of the whole record and in the public interest.

1. 2011 GRC Revenue Requirement (Section 3.1)

PG&E requested that the Commission adopt a 2011 CPUC jurisdictional GRC retail revenue requirement increase of $1,064 million.[31/] DRA recommended an increase of $181

28/ Tr. Vol. 1, p. 19:15-26.

29/ ACR, p. 6, fn. 6.

30/ CPUC Rule 12.1(d).

31/ Ex. PG&E-69, p. 1-5, Table 1-1.

million.[32/] Although no other party calculated an overall revenue requirement figure, many parties recommended substantial reductions to PG&E's forecast and agreed with some or all of DRA's recommendations.[33/] In Section 3.1 of the Agreement, the Settling Parties agree that, for the issues resolved in this Agreement, PG&E's 2011 CPUC jurisdictional GRC retail revenue requirement shall be $5,977 million, a 2011 revenue requirement increase of $395 million, to be constructed based on other terms herein.

The Settling Parties' agreement on the overall revenue requirement represents a compromise from the litigation positions of the Settling Parties and is reasonable when compared to the Settling Parties' litigation positions.

2. Electric Distribution (Section 3.2)

The area of Electric Distribution covers the cost of operating, maintaining, and expanding PG&E's Electric Distribution system, including connecting new customers, repairing or replacing damaged or deteriorated facilities, coping with an aging infrastructure, addressing operational support systems, and responding to emergencies and outages.[34/]

a. Revenue Requirement Issues (Section 3.2.1)

In Section 3.2.1 of the Agreement, the Settling Parties agree to $571 million for Electric Distribution O&M expense and $1,270 million for capital expenditures for 2011. The Settling Parties agree that PG&E's Electric Distribution expense and capital-related revenue requirement forecast shall be reduced by at least $52 million. PG&E's 2011 electric distribution request was

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32/ Ex. PG&E-69, p. 1-5, Table 1-1.

33/ Ex. PG&E-69, Appx. H.

34/ Ex. PG&E-3, p. 1-1, lines 6-11.

$1.95 billion, with $1.37 billion for capital expenditures and $0.580 billion (Fully Burdened dollars) for expense.[35/]

DRA's litigation position sought a $218.4 million reduction in expense and capital expenditures related to Electric Distribution.[36/] TURN and other intervenors also sought various reductions in the area of Electric Distribution.[37/]

The Settling Parties' agreement on the overall revenue requirement reduction for Electric Distribution represents a compromise from the litigation positions of PG&E, DRA, and TURN. The overall reduction includes: removal of $8 million (Fully Burdened dollars) expense forecast for New Business/WRO; $18.5 million for vegetation management; and $2 million for the LED Streetlight Replacement Project.[38/] These terms are explained below.

(1) New Business/WRO (Section 3.2.1(a))

PG&E requested that the Commission adopt its 2011 expense forecast of $17.5 million for New Business, which expenses reside in MWC EV, and its 2011 expense forecast of $25.3 million for WRO, which resides in MWC EW.[39/] DRA recommended an overall reduction of $1.0 million in expense for New Business and $3.3 million for WRO.[40/] CFC commented on

35/ Ex. PG&E-3, p. 1-42, Table 1-2, line 48.

36/ Ex. DRA-5, p. 7, Table 5-1; Ex. DRA-6, p. 3, Table 6-1.

37/ *See e.g.,* Ex. CAL-SLA, p. 14, line 15 to p. 15, line 14.

38/ Section 2.5.1(a)-(c) of the Agreement.

39/ Ex. PG&E-3, p. 6-3, Table 6-2.

40/ Ex. DRA-5, p. 58, lines 1-2. CFBF and CAL-SLA adopted DRA's position. Ex. CFBF-1, p. 4, Table 2, Ex. CFBF-1 Errata, p. 4, Table 2; Ex. CAL-SLA, p. 14, lines 11-13.

PG&E's New Business forecast, testifying that the net cost of extensions of service is unknown.[41/]

Section 3.2.1(a) of the Agreement provides that PG&E shall remove $8 million in forecast New Business/WRO from PG&E's requested GRC revenue requirements. Given DRA's and CFC's recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(2) Vegetation Management (Section 3.2.1(b))

PG&E requested that the Commission adopt its 2011 expense forecast of $180 million for Vegetation Management, which expenses reside in MWC HN.[42/] DRA recommended an overall reduction of $19.3 million.[43/] TURN recommended an overall reduction of $18.5 million.[44/] CFC made no specific funding recommendation for vegetation management, but questioned the prudence of PG&E's forecast increase.[45/]

Section 3.2.1(b) of the Agreement provides that PG&E shall remove $18.5 million from PG&E's requested GRC revenue requirement for vegetation management. Specifically, this provision adopts TURN's recommendation. Given the intervenors' various recommendations in this area, this provision is supported by the record. And, in light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

41/ Ex. CFC-1, p. 21, lines 3-11 and p. 34, lines 3-4; Ex. CFC-29, p. 20, lines 21-26 and p. 21, lines 1-2.

42/ Ex. PG&E-3, p. 5-1, lines 17-18.

43/ Ex. DRA-5, p. 45, lines 19-20. CFBF and CAL-SLA adopted DRA's position. Ex. CFBF-1, p. 4, Table 2; Ex. CFBF-1 Errata, p. 4, Table 2; Ex. CAL-SLA, p. 14, lines 11-13.

44/ Ex. TURN-3, pp. 25-26.

45/ Ex. CFC-1, p. 20, lines 16-21; Ex. CFC-29, p. 20, lines 6-11.

(3) LED Streetlight Project (Section 3.2.1(c))

PG&E requested that the Commission adopt its 2011 capital forecast of $20.5 million for the LED Streetlight Project, which expenditures reside in MWC 57.[46/] DRA recommended a reduction of $10.2 million in capital based on doubling the duration of the 5-year project.[47/] Both TURN and CAL-SLA recommended disallowing the project.[48/]

Section 3.2.1(c) of the Agreement provides that PG&E shall remove $2 million from PG&E's requested GRC revenue requirement for the LED Streetlight Project calculated based on the entire capital forecast for the project. Hence, the Agreement adopts TURN's and CAL-SLA's recommendations for funding and takes into consideration DRA's recommended adjustment. Given the intervenors' recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

b. Other Electric Distribution Issues (Section 3.2.2)

In addition to the Electric Distribution revenue requirement issues discussed above, the Settling Parties also agreed to non-revenue requirement terms in the following areas: Vegetation Management, Rule 20A, and Electric RD&D.

(1) Vegetation Management (Section 3.2.2(a))

PG&E has proposed retention of its current one-way Vegetation Management Balancing Account (VMBA) and the separate tracking account described in the "Incremental Inspection

46/ Ex. PGE-3, p. 2-50, lines 12-14 and p. 2-51, lines 22-23.

47/ Ex. DRA-6, p. 19, lines 4-6 and 13-14. CFBF implicitly agreed with DRA's recommendation. Ex. CFBF-1, p. 3.

48/ Ex. CAL-SLA, p. 14, lines 19-26; Ex. TURN-8, pp. 28-29.

and Removal Cost Tracking Account Accounting Procedure" in PG&E's Electric Preliminary Statement Part BU.[49/]

No party opposed PG&E's proposal, which the Agreement adopts, in conjunction with a provision setting the cap for both accounts at $161.5 million (Fully Burdened dollars). Given the evidence provided on this issue, the adoption of PG&E's proposal is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(2) Rule 20A (Section 3.2.2(b))

PG&E proposed three adjustments to address the accumulation of Rule 20A work credits: First, PG&E proposed allocation of work credits at the same level and in the same amount as the Rule 20A "annual budgeted amount" as opposed to use of an escalation factor.[50/] Second, PG&E proposed: (a) a $50 million "annual budgeted amount" consistent with recent expenditures and GRC forecasts (and equal to the amount of work credits PG&E proposed to allocate in this GRC period); and (b) a separate $30 million "work down" amount which would not be part of the annual allocation for work credits but would be used to work down the backlog of work credits.[51/] Third, PG&E requested that the Commission allow communities with projects already in progress to continue with those projects even if they exceed the five-year allowable borrowing.[52/]

49/ Ex. PG&E-3, p. 5-2, lines 1-11; and p. 5-10, lines 14-17, fn. 2.

50/ Ex. PG&E-3, p. 7-9, lines 6-18.

51/ Ex. PG&E-3, p. 7-9, line 20 to p. 7-10, line 5.

52/ Ex. PG&E-3, p. 7-10, lines 13-23.

DRA acknowledged that PG&E's "proposal to change the way work credits are calculated is a positive change," but proposed working through the existing accumulation of work credits by instituting a ten-year moratorium on allocating new work credits rather than PG&E's proposal to reduce the work credits allocated and create a $30 million work down amount.[53/] No other party addressed PG&E's work credit allocation proposal.

Section 3.2.2(b) of the Agreement provides that PG&E shall allocate work credits at the same level and in the same amount as PG&E's Rule 20A annual budgeted project amount for 2010, in order to stop the escalation of work credit allocations. The Agreement allows communities with projects already in progress to continue with their projects, even if they exceed the five-year allowable borrowing period under the modified Rule 20A allocation method adopted herein. Given PG&E's and DRA's positions on this issue, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(3) Electric RD&D (Section 3.2.2(c))

In response to PG&E's proposal for Electric RD&D funding, both SSJID[54/] and DACC proposed that PG&E track generation and distribution costs separately, and DACC proposed that the results of PG&E's electric RD&D be placed in the public domain.[55/]

The Agreement provides that electric RD&D project costs shall be reasonably allocated between generation and distribution as PG&E preliminarily outlined in Table 31-2, Exhibit PG&E-18v3c, p. 31-11 (except for energy storage, for which PG&E has revised its forecast

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53/ Ex. DRA-8, p. 21, lines 3-6; p. 22, lines 9-11.

54/ SSJID's primary litigation position was to disallow the program entirely.

55/ Ex. PG&E-18 v3c, Ch. 31; Ex. SSJID-1, p. 36, line 10 and p. 43, Table 4-1; Ex. DACC-1, p. 10, lines 11-16 and p. 11, lines 5-9.

allocation to 50/50 generation/distribution). The Agreement also states that for the test year 2011 GRC cycle the results of PG&E's prospective electric RD&D projects described in Exhibit PG&E-18v3c, Chapter 31 shall be placed in the public domain to the extent allowed by grid security considerations.

Given PG&E's, SSJID's and DACC's positions on this issue, this provision is supported by the record. Specifically, the Agreement adopts DACC's recommendations on this issue, except for energy storage, which reflects a compromise between DACC's and PG&E's positions on this issue. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

3. Gas Distribution (Section 3.3)

The area of Gas Distribution covers the cost of operating, maintaining, and expanding PG&E's Gas Distribution system, including connecting new customers, repairing or replacing damaged or deteriorated facilities, coping with an aging infrastructure, addressing operational support systems, and responding to emergencies and service interruptions.[56/]

a. Revenue Requirement Issues (Section 3.3.1)

In Section 3.3 of the Agreement, the Settling Parties agree to $196 million for Gas Distribution expense and $258 million for capital expenditures for 2011. The Settling Parties agree that PG&E's Gas Distribution expense and capital-related revenue requirement forecast shall be reduced by at least $30 million. PG&E's 2011 gas distribution forecast was $438.7 million (Fully Burdened dollars), with $257 million for capital expenditures and $181.7 million for expense.[57/]

56/ Ex. PG&E-3, p. 1-1, lines 6-11, and p. 1-25, lines 3-5.

57/ Ex. PG&E-3, p. 1-46, Table 1-3, line 30.

DRA's litigation position sought a $130.1 million reduction in expense and capital expenditures related to Gas Distribution.[58/] TURN and CFC also sought various reductions in the area of Gas Distribution.

The Settling Parties' agreement on the overall revenue requirement reduction for Gas Distribution represents a compromise from the litigation positions of each of these Settling Parties. The overall reduction includes: removal of $4 million forecast MWC EX for the gas meter protection program; removal of $4.6 million in MWC DG for cathodic protection of isolated services; and a commitment to maintain currently mandated levels of gas inspection work.[59/] These terms are explained below.

(1) Gas Meter Protection Program (Section 3.3.1(a))

PG&E requested that the Commission adopt its 2011 expense forecast of $5.2 million for the Gas Meter Protection Program, which expenses reside in MWC EX.[60/] DRA recommended an overall reduction of $4.6 million in expense for the Gas Meter Protection Program.[61/]

Section 3.3.1(a) of the Agreement reflects a reduction of $4 million in forecast Gas Meter Protection Program expenses from PG&E's requested GRC revenue requirement. Specifically, the Agreement adopts a figure close to DRA's recommendation. Given PG&E's and DRA's recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

58/ Ex. DRA-7, p. 3, Table 7-1; Ex. DRA-8, p. 6, Table 8-1.

59/ Section 3.3.1 of the Agreement.

60/ Ex. PG&E-3, p. 19-22, Table 19-7.

61/ Ex. DRA-7, p. 3, Table 7-1; Ex. CFBF-1, p. 3.

(2) Cathodic Protection of Isolated Services (Section 3.3.1(b))

PG&E requested that the Commission adopt its 2011 expense forecast of $5.817 million for cathodic protection of isolated services, which expenses reside in MWC DG.[62/] DRA and TURN recommended an overall reduction of $4.6 million in expense for cathodic protection of isolated services, based on their belief that PG&E would not install cathodic protection on more than 34,000 isolated services per year in 2011 and attrition years.[63/]

Section 3.3.1(b) of the Agreement reflects a reduction of $4.6 million in forecast for cathodic protection of isolated services expenses from PG&E's requested GRC revenue requirement.[64/] Specifically, the Agreement adopts DRA's and TURN's recommendation. Accordingly, this provision is supported by the record and, in light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(3) Gas Leak Inspection Work (Section 3.3.1(c))

PG&E requested that the Commission adopt its 2011 expense forecast of $5.2 million for transitioning from a five-year to a three-year gas leak survey cycle, which expenses reside in MWC DE.[65/] PG&E's proposal to transition from a five-year to a three-year survey cycle was consistent with, though not mandated by, general requirements found in the DIMP regulation.[66/] DRA recommended a reduction of $0.9 million in expense for the transition from a five-year to a

62/ Ex. PG&E-3, p. 18-19, Table 18-5, line 10; Ex. PG&E-18 v3b, p. 28-33, lines 2-6.

63/ Ex. DRA-7, p. 24, Table 7-7; Ex. TURN-1, p. 40. CFBF implicitly adopted DRA's position. Ex. CFBF-1, p. 3.

64/ This reduction is not intended to affect PG&E's regulatory commitments in this area.

65/ Ex. PG&E-3, p. 17-18, line 5.

66/ Ex. PG&E-3, p. 17-19, lines 12-18.

three-year gas leak survey cycle, based on its criticisms of PG&E's unit cost methodology.[67/] TURN recommended a reduction of $1.9 million, based on a four-year levelization applied to PG&E's proposal.[68/]

Section 3.3.1(c) of the Agreement provides PG&E funding sufficient to maintain currently mandated levels of gas leak inspection work. Given PG&E's, DRA's, and TURN's recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

b. Other Gas Distribution Issues (Section 3.3.2)

PG&E requested that the Commission adopt its 2011 expense forecast of $36.5 million for DIMP, which expenses reside in MWCs DE, DF, DG, and DI.[69/] DRA recommended an overall reduction of $25.1 million in expense for DIMP based on criticism of PG&E's unit and unit cost calculations.[70/] TURN recommended an additional reduction of $1.0 million for DIMP based on an adjustment to PG&E's proposed DIMP leak survey cycle.[71/] CFC argued that PG&E should have included estimated cost savings in its adjustment to offset PG&E's forecasted DIMP expenditures.[72/]

Section 3.3 of the Agreement requires that PG&E create a MWC for its DIMP, with a one-way balancing account mechanism set at $60 million for DIMP costs for the term of the

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67/ Ex. DRA-7, p. 20, lines 10-18; Ex. CFBF-1, p. 3.

68/ Ex. TURN-13, pp. 39-40.

69/ Ex. PG&E-3, p. 17-9, Table 17-1.

70/ Ex. DRA-7, p. 8, lines 10-12; Ex. CFBF-1, p. 3.

71/ Ex. TURN-13, pp. 39-40.

72/ CFC-1, p. 16, line 20 to p. 17, line 7; Ex. CFC-29, p. 16 line 11 to p. 17, line 5.

GRC cycle (2011-2013). Any net unspent DIMP funds at the end of this GRC cycle would be returned to customers in the next GRC. The types of work this funding would cover include development and improvements in the following areas: DIMP program, preventive maintenance, leak surveys, operator qualifications, training and programs such as cross-bored sewer, marker ball installation, and Aldyl-A.

Given PG&E's, DRA's, TURN's and CFC's recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

4. Energy Supply (Section 3.4)

The purpose of PG&E's Energy Supply organization is to manage PG&E's portfolio of owned and contracted energy resources.[73/]

a. Revenue Requirement Issues (Section 3.4.1)

PG&E's litigation position requested 2011 expense of $635 million and 2011 capital spending of $366.3 million.[74/] Under the terms of the Agreement, PG&E's Energy Supply O&M expenses and capital-related revenue requirements will be reduced by at least $42 million. The

73/ Ex. PG&E-5, p. 1-1, lines 8-9.

74/ Ex. PG&E-5, p. 1-3, Table 1-1. PG&E's forecast of its operating expenditures for the Energy Supply Organization covers: (1) the cost of operating and maintaining PG&E's Diablo Canyon Power Plant, 68 hydroelectric powerhouses and one existing fossil generation facility; (2) the capital and operating costs associated with 1,400 megawatts (MW) of new highly efficient conventional power plants - the Gateway Generating Station (GGS or Gateway), Colusa Generating Station (CGS or Colusa) and Humboldt Bay Generating Station (HBGS); (3) the administrative costs of managing PG&E's portfolio of contracted resources, including power trading, settlements, and administering PG&E's existing power purchase contracts as well as renewable energy compliance costs, renewable energy development costs, green house gas (GHG) regulation implementation costs and acquisition costs associated with obtaining long-term electric supply resources for PG&E's customers; and (4) the costs associated with the current undercollection of the fossil decommissioning reserve based on recently updated studies. The Energy Supply GRC request ***does not*** include the following items: (1) cost of fuel for PG&E's generation facilities and purchased power; (2) cost of power for the California Department of Water Resources (CDWR) contracts; (3) costs of nuclear decommissioning; (4) the cost of PG&E's Photovoltaic (PV) and State Fuel Cell Programs. Ex. PG&E-5, pp. 2-1 to 2-3.

following Settling Parties raised issues that pertain to the Energy Supply area: DRA, TURN, Aglet, DACC, EPUC, and WPTF. As described in more detail below, these issues included proposed reductions in hydroelectric O&M and capital, Diablo Canyon O&M, new fossil generation O&M, fossil decommissioning, renewable energy project development O&M, and cost recovery for the cancelled Tesla Power Plant. All of the issues raised by these parties applicable to Energy Supply are resolved in the Agreement.

(1) New Small Hydroelectric Costs/Britton Powerhouse (Sections 3.4.1(a) and (c))

PG&E proposed to recover the capital costs associated with five new small hydro projects, although it later updated the request to reflect deferral of all but one of these projects, the Britton Project, in the test year 2011 rate case period. DRA and TURN opposed PG&E's proposed new small hydroelectric capital additions primarily on the grounds that they are not cost-effective as forecast and/or that actual project costs may be higher than forecast.[75/]

Section 3.4.1(a) states that the new small hydroelectric generation plants installed after test year 2011 are not approved in this proceeding but will be reviewed in PG&E's next GRC. Section 3.4.1(c) states that the costs of the Britton Power House are removed from the 2011 test year since its projected on-line date occurs after the test year. Future review of the new small hydroelectric projects, including Britton, will include a cost comparison with other renewable resource alternatives. This reduction is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense and capital-related revenue requirement. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

75/ Ex. DRA-9C, pp. 11-14; Ex. TURN-1, pp. 46-50.

(2) Tesla Power Plant (Section 3.4.1(b))

PG&E requested Commission approval to (1) classify the Tesla project acquisition costs as plant held for future use (PHFU) so that the project may be retained for potential future development and (2) authorize PG&E to amortize in rates certain one-time termination costs related to cancelled equipment for the project as abandoned project costs.

PG&E's position is that the Tesla site has the potential for being needed for utility purposes in the future and that it satisfies the CPUC's criteria for PHFU. DRA and several other parties proposed to disallow $28.3 million associated with PG&E's request to classify Tesla acquisition and development costs as PHFU.[76/] DRA, DACC, EPUC and WPTF also opposed PG&E's request for recovery of $4.8 million in Tesla project cancellation costs as abandoned project costs.[77/]

Section 3.4.1(b) states that the test year 2011 revenue requirement includes a reduction of $3.5 million related to Tesla PHFU. However, PG&E reserves the right to address Tesla PHFU treatment in another proceeding. Section 3.4.1(b) also states that the test year 2011 revenue requirement includes a reduction of $1.6 million related to Tesla cancellation expense. Resolution of these issues is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

(3) RRD Costs (Section 3.4.1(d))

PG&E proposed to establish a $27 million one-way balancing account for RRD to fund external development and environmental assessment costs associated with feasibility

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76/ Ex. DRA-9, pp. 43-44; Ex. DACC-1, pp. 12-13; Ex. WPTF-1, pp. 4-8; Ex. EPUC-27, pp. 30-37.

77/ Ex. PG&E-5, pp. 6-85 to 6-88.

assessments of potential utility-owned renewable projects. DRA, Aglet, WPTF, and DACC opposed this request on the grounds that the request potentially provides a subsidy for PG&E-owned renewable projects over third-party developer projects.[78/]

Section 3.4.1(d) states that PG&E's request for the RRD balancing account is withdrawn and there will be no memorandum account for RRD costs during the test year 2011 GRC cycle. Resolution of this issue is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

(4) Utility Renewable Investments (Section 3.4.1(e))

PG&E proposed approximately $10 million to fund the internal staffing for the RRD group. DRA, Aglet, WPTF, and DACC opposed this request because it potentially provides a subsidy for PG&E-owned renewable projects over third-party developer projects.[79/]

Section 3.4.1(e) reduces the overall revenue requirement for Energy Procurement by $8 million to resolve issues associated with utility renewable investments. Resolution of this issue is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

(5) Kilarc-Cow Decommissioning Project (Section 3.4.1(f))

PG&E requested a 1% rate of return incentive for the Kilarc-Cow decommissioning project in recognition of PG&E's decision to decommission the Kilarc-Cow Creek Project as this will substantially benefit endangered species and provide incentives for future environmentally

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78/ Ex. DACC-1, p. 12; Ex. Aglet-3, p. 59; Ex. DRA-9, pp. 36-38; Ex. WPTF-1, pp. 11-14.

79/ Ex. DACC-1, p. 12; Ex. Aglet-3, p. 59; Ex. DRA-9, pp. 36-38; Ex. WPTF-1, pp. 11-14.

beneficial initiatives. DRA and EPUC asserted that the request does not fit within the definition of a project that qualifies for the rate of return enhancement under California Public Utilities Code Section 454.3.

Section 3.4.1(f) states that the requested rate of return enhancement on the Kilarc-Cow decommissioning project is removed. This reduction is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

(6) Hydroelectric Generation Capital (Section 3.4.1(g))

EPUC proposed a reduction to PG&E's forecast of reliability-related capital expenditures for hydroelectric facilities of $250 million over the 2010 to 2013 period. EPUC recommended that PG&E's hydroelectric reliability investments be held to a portion of the historic average of the recorded expenditures in 2006-2008 plus some targeted supplemental funding for the projects with forced outage factors that are worse than industry average.

Section 3.4.1(g) provides that PG&E's 2011 revenue requirement will be reduced by $2 million to reflect reductions in hydroelectric capital expenditures. This reduction is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense and capital-related revenue requirements. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

(7) NEI Fees (Section 3.4.1(h))

PG&E proposed to recover approximately 97% of its forecast of NEI fees, with a small reduction attributable to lobbying activities. TURN recommended that the Commission continue to apply a 50% disallowance to NEI fees on the grounds that PG&E has not provided sufficient documentation supporting 100% recovery.[80/]

Section 3.4.1(h) states that PG&E shall record 50% of its forecasted costs for NEI fees below-the-line. Specifically, this provision adopts TURN's recommendation. This provision is supported by the record, reasonable, and in the public interest.

(8) LTSA Payments (Section 3.4.1(i))

PG&E proposed that the cost of payments for major maintenance at Colusa, Gateway, and HBGS, which occurs once every three to four years, be spread over the two- to three-year period before the payment is made. DRA and TURN both supported the levelized recovery approach. DRA would allow PG&E to recover its costs for all three plants on a lagging basis starting in the year of the LTSA milestone payment and the two years following.[81/] TURN proposed to use DRA's lagging method only for Gateway and PG&E's method for Colusa and Humboldt.[82/]

Section 3.4.1(i) states, "[f]or PG&E's new fossil generation plants, only one long term service agreement (LTSA) payment shall be collected through normalized funding per plant. This results in a test year reduction of the O&M revenue requirement for the Gateway Generating Station." Resolution of this issue is subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense and capital-related revenue requirements. Given the positions taken by intervenors, this provision is supported by the record, reasonable, and in the public interest.

80/ Ex. TURN-1C, pp. 51-52.

81/ Ex. DRA-9, p. 28, Figure 9-8.

82/ Ex. TURN-1C, p. 53.

b. Other Energy Supply Issues (Section 3.4.2)

In the Settlement Agreement, the Settling Parties have also agreed on a number of additional ratemaking and compliance issues that pertain to generation ratemaking, as described below.

(1) Spent Nuclear Fuel Removal (Section 3.4.2(a))

PG&E proposed to capitalize the labor costs associated with spent nuclear fuel removal, drying, and encapsulation as part of its dry cask storage project. Aglet recommended that dry cask storage load campaign labor costs should be removed from the Diablo Canyon capital forecast and reclassified as expense.[83/]

Section 3.4.2(a) states that labor costs associated with Diablo Canyon nuclear fuel removal, drying, and encapsulation will be treated as an operating expense. This results in a decrease to PG&E's capital spending for the activity and an increase in PG&E's O&M expense. These adjustments are subsumed in the overall reduction of at least $42 million of Energy Supply O&M expense.

Given Aglet's recommendation, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(2) Diablo Canyon Steam Generator Replacement Project (Section 3.4.2(b))

In compliance with D.05-02-052, PG&E identified the final project costs of the Diablo Canyon Steam Generator Replacement Project (SGRP) and requested authorization to place the final costs of the Diablo Canyon SGRP in rates. The total cost of the SGRP was $695 million,

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83/ Ex. Aglet-3, pp. 48-49.

which is below the $706 million reasonable capital cost, as adjusted for inflation and cost of capital, adopted in D.05-02-052. PG&E's request was uncontested.

Section 3.4.2(b) provides that since the SGRP was completed at a final cost below the costs (as adjusted) adopted in D.05-02-052, the costs shall be recovered in generation rates without the need for further reasonableness review. Given the uncontested nature of this issue, this provision is supported by the record, reasonable and in the public interest.[84/]

(3) Gateway Settlement Balancing Account (Section 3.4.2(c))

In compliance with D.06-06-035, PG&E included a ratemaking proposal to place the final costs of the Gateway Generating Station (GGS) in generation rates. This proposal was uncontested. Decision 06-06-035 adopted a cost-sharing mechanism for the initial capital cost of the GGS. That mechanism allows PG&E to only collect 90% of any capital costs above $380.5 million, up to a limit of $420.5 million. Currently, PG&E forecasts the initial capital cost of the GGS to be $386.6 million. Therefore, PG&E has included $386.0 million in the rate base for the initial capital cost of the GGS.[85/]

Section 3.4.2(c) provides that PG&E shall be allowed to transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account (UGBA) when the total costs of the project are known, and PG&E shall be allowed to close out the

84/ In furtherance of D.05-02-052, the Settling Parties support the following finding in a CPUC decision approving the Agreement:

"Because the Diablo Canyon Steam Generator Replacement Project was completed at a final cost below the $706 million reasonable capital cost, as adjusted for inflation and cost of capital, adopted in D.05-02-052, the costs will be recovered in generation rates without the need for further reasonableness review."

85/ Advice Letter 3400-E established the Gateway Settlement Balancing Account to track "the difference in the RRQ associated with the Gateway Generation Station based on the adopted capital cost of $370.5 million and the actual capital cost."

Gateway balancing account at that time. Given the uncontested nature of this issue, this provision is supported by the record, reasonable, and in the public interest.[86/]

(4) True-up of Initial Cost of Colusa Generating Station (Section 3.4.2(d))

In compliance with D.06-11-048, PG&E included a ratemaking proposal to place the final costs of the Colusa Generating Station (CGS) in generation rates. PG&E forecasts that the initial capital cost of the CGS will be equal to the CPUC-required amount of $672.8 million as adopted in D.06-11-048. This proposal was uncontested.

Section 3.4.2(d) provides that with respect to the true-up of the initial cost of the CGS, PG&E is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known. Given the uncontested nature of this issue, this provision is supported by the record, reasonable, and in the public interest.[87/]

86/ In furtherance of D.06-06-035, the Settling Parties support the following finding in a CPUC decision approving the Agreement:

"It is reasonable that PG&E be allowed to transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account (UGBA) when the total costs of the project are known, and close out the Gateway balancing account at that time."

87/ In furtherance of D.06-11-048, the Settling Parties support the following finding and ordering paragraph in a CPUC decision approving the Agreement:

Finding: "PG&E forecasts that the initial capital cost of the Colusa Generating Station (CGS) will be equal to the CPUC-required amount of $672.8 million as adopted in Decision 06-11-048. The Agreement allows PG&E to retroactively true-up the project's initial capital cost in the next GRC following operation to reflect 50 percent of any other savings relative to the initial capital cost for CGS."

Ordering Paragraph: "PG&E is authorized to file an advice letter to true-up the Colusa Generating Station project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known."

(5) True-up of Initial Capital Cost of Humboldt Bay Generating Station (Section 3.4.2(e))

In compliance with D.06-11-048, PG&E included a ratemaking proposal to place the final costs of the Humboldt Bay Generating Station (HBGS) in generation rates. Decision 06-11-048 requires PG&E to track in a memorandum account the difference between the estimated capital cost and the actual capital cost of the HBGS (including 100% of any cost savings) and to true up the difference in the next GRC following commercial operation. This proposal was uncontested.

Section 3.4.2(e) provides that with respect to the true-up of the initial cost of the HBGS, PG&E is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known. Given the uncontested nature of this issue, this provision is supported by the record, reasonable, and in the public interest.[88/]

(6) Recovery Costs in Excess of Authorized Initial Capital Cost of HBGS (Section 3.4.2(f))

In PG&E's GRC Application, in compliance with D.06-11-048, PG&E included a proposal for HBGS to recover "additional costs incurred as a result of … changes to the project as a result of new regulatory requirements or other external events."[89/] HBGS is subject to an

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88/ In furtherance of D.06-11-048, the Settling Parties support the following finding and ordering paragraph in a CPUC decision approving the Agreement:

Finding: "PG&E forecasts that the initial capital cost of Humboldt Bay Generating Station will be equal to the CPUC-authorized amount of $238.6 million. D.06-11-048 requires PG&E to true up the difference between the estimated capital cost and the actual capital cost of the project in the next GRC following commercial operation."

Ordering Paragraph: "PG&E is authorized to file an advice letter to true-up the Humboldt Bay Generating Station project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known."

89/ D.06-11-048, *mimeo*, p. 24.

additional $25 million change order due to an increase in California sales and use taxes and to address a change in configuration at the plant required by the California Energy Commission (CEC) permit to address changes in the building code and air emissions criteria. Both of these cost drivers were beyond PG&E's control and PG&E was not capable of forecasting them. PG&E therefore requested in the GRC application that it be authorized to increase the initial capital cost target approved for the project by up to $25 million by advice letter to the extent the project's actual costs exceed the initial cap. This proposal was uncontested.

Section 3.4.2(f) provides that with respect to the recovery of costs in excess of the authorized initial cost of HBGS, PG&E is authorized to increase the initial capital cost target approved for the project by up to $25 million by advice letter to the extent the project's actual costs exceed the initial cost target. If the actual project costs exceed the cap by more than $25 million, as specified in D.06-11-048, PG&E shall be required to file an application with the Commission demonstrating the reasonableness of any excess amounts. Given the uncontested nature of this issue, this provision is supported by the record, reasonable, and in the public interest.[90/]

90/ In furtherance of D.06-11-048, the Settling Parties support the following finding and ordering paragraph in a CPUC decision approving the Agreement:

Finding: "Decision 06-11-048 approving Humboldt Bay Generating Station authorizes PG&E to seek recovery of costs in excess of the authorized initial capital cost of $238.6 million, if such excess costs are incurred as a result of 'changes to the project as a result of new regulatory requirements or other external events.' PG&E has demonstrated that an additional $25 million was incurred at HBGS due to an increase in California sales and use taxes and to address a change in configuration at the plant required by the CEC permit to address changes in the building code and air emissions criteria."

Ordering Paragraph: "PG&E is authorized to increase the initial capital cost target approved for the Humboldt Bay Generating Station project by up to $25 million by advice letter, as opposed to an application, to the extent the project's actual costs exceed the initial cost target. If the actual project costs exceed the cap by more than $25 million, as specified in D.06-11-048, PG&E shall file an application with the Commission demonstrating the reasonableness of any excess amounts."

(7) Hunters Point Decommissioning (Section 3.4.2(g))

In response to questions raised by intervenors regarding the meaning of PG&E's testimony on Hunters Point decommission costs, Section 3.4.2(g) clarifies that PG&E stands by its prior commitment to remediate the Hunters Point Power Plant site to residential standards that are appropriate for the type of future residential development and consistent with the direction of regulators. Section 3.4.2(g) also clarifies that PG&E may file a subsequent application to recover additional site-specific environmental remediation costs to the extent necessary to accommodate the development plan ultimately approved for the Hunters Point site.

(8) U.S. Department of Energy Litigation Status Report (Section 3.4.2(h))

Aglet proposed that PG&E be required to provide a status report in the next GRC on the status of PG&E's litigation against the U.S. Department of Energy for breach of contract associated with long-term storage of spent nuclear fuel.[91/]

In Section 3.4.2(h), PG&E agrees that it will provide in the next GRC a status report on spent nuclear fuel payments made to the U.S. Department of Energy, associated lawsuits, and responsibility for the costs of on-site spent fuel storage at PG&E facilities. In light of Aglet's proposal, this provision is supported by the record, reasonable, and in the public interest.

5. Customer Care (Section 3.5)

PG&E's Customer Care organization provides the "face" of PG&E, answering phone calls, relighting pilot lights, investigating gas leaks, obtaining meter reads, and sending bills and notices to customers.[92/]

91/ Ex. Aglet-3, p. 2, lines 24-27, and p. 45, lines 3-16.

92/ Ex. PG&E-4, p. 1-1, lines 18-25.

a. Revenue Requirement Issues (Section 3.5.1)

In Section 3.5.1 of the Agreement, the Settling Parties agree that PG&E's forecast for Customer Care expense and capital-related revenue requirement shall be reduced by at least $137 million. PG&E originally sought expenses of $630.5 million for 2011 customer care activities, but PG&E reduced its request through concessions, errata, and adjustments to $617.1 million for these activities.[93/]

DRA's litigation position sought a $137 million reduction in the expense and capital expenditures related to Customer Care.[94/] TURN and Aglet also sought various reductions in the area of Customer Care.[95/]

The Settling Parties' agreement on the overall revenue requirement reduction for Customer Care represents a compromise from the litigation positions of the Settling Parties. The overall reduction includes: removal of $113 million (Fully Burdened dollars) forecast meter reading costs, $10 million of peak day pricing expense, and $7 million for customer retention and economic development.[96/] These terms are explained below.

(1) Meter Reading Costs (Section 3.5.1(a))

PG&E requested that the Commission adopt its 2011 expense forecast of $113.6 million,[97/] which expenses reside in MWC AR.[98/] DRA recommended an overall reduction of

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93/ Ex. PG&E-4, p. 1-3, line 21.

94/ Ex. DRA-10, p. 3, Tables 10-1 and 10-2.

95/ Ex. TURN-6, p. 2, Table 1; Ex. Aglet-3, p. 21, line 20 to p. 22, line 3.

96/ Section 3.5.1(a)-(c) of the Agreement.

97/ Ex. PG&E-4, p. 7-1, lines 24-25.

98/ Ex. PG&E-4, p. 7-7, Table 7-1.

$0.6 million in expense relating to new business projections.[99/] TURN recommended that all meter reading costs be excluded from this GRC and, instead, be booked and recovered via a subaccount of the SmartMeter Balancing account.[100/] TURN's recommendation would remove from the GRC the entirety of PG&E's $113.6 million forecast in this area.

Section 3.5.1(a) of the Agreement provides that PG&E shall remove $113 million (Fully Burdened dollars) in forecast meter reading costs from requested GRC revenue requirements. Instead, PG&E shall record actual meter reading costs in a new balancing account, up to an annual cap of $76.2 million (Fully Burdened dollars), for recovery in annual revenue consolidation proceedings. Given TURN's recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, the provision is in the public interest.

(2) Customer Retention and Economic Development (Section 3.5.1(b))

PG&E forecasted $4.0 million in 2011 expense for customer retention work. These expenses reside in MWC FK.[101/] DRA, Aglet, Merced and Modesto, SSJID, Greenlining, WEM, and DACC, each recommended that PG&E receive no funding for its customer retention work.[102/] WEM argued that ratepayers "would benefit far more by becoming ratepayers of publicly owned utilities."[103/]

99/ Ex. DRA-10, p. 25, lines 9-11.

100/ Ex. TURN-6, p. 54, lines 9-16.

101/ Ex. PG&E-4, p. 9-1, Table 9-1.

102/ Ex. DRA-10, p. 2, line 6; Ex. Aglet-3, p. 2, lines 10-12; Ex. MODMER-1, p. 1, line 26 to p. 2, line 1; and Ex. MOD-1, p. 1, lines 28-29; Ex. SSJID-1, p. 23, lines 19-21; Ex. Greenlining-2, p. 40, lines 20-22; and Ex. DACC-1, p. 8, lines 12-13.

103/ Ex. WEM-16, p. 11.

PG&E forecasted $3.0 million in 2011 expense for economic development work. These expenses also reside in MWC FK.[104/] DRA and Aglet recommended an overall reduction of $3 million.[105/] Greenlining recommended a reduction of at least $2 million.[106/] DACC supported PG&E's request, contingent on greater oversight by the Commission.[107/]

Section 3.5.1(b) of the Agreement provides for a revenue requirement reduction of $7 million associated with the above-described work and, during the 2011 GRC cycle, PG&E will record the above-described customer retention costs below-the-line. Given the parties' recommendations in this area, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(3) Peak Day Pricing Expense (Section 3.5.1(c))

In PG&E's direct testimony, PG&E forecast $33 million in costs related to the implementation of the dynamic pricing rate called peak day pricing.[108/] DRA recommended removal of about $38 million of peak day pricing costs from the GRC and urged that such costs be considered in the Rate Design Window or some other venue.[109/] TURN recommended

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104/ Ex. PG&E-4, p. 9-1, Table 9-1; Ex. PG&E-18 v4, p. 41-3, lines 9-12 (reducing forecast by $11,000).

105/ Ex. DRA-10, p. 37, lines 18-20; and Ex. Aglet-3, p. 2, lines 10-12.

106/ Ex. Greenlining-2, p. 42, lines 12-13.

107/ Ex. DACC-1, p. 9, lines 11-13.

108/ Ex. PG&E-4, pp. 2-6 to 2-8 ($4.7 million), p. 4-27, Table 4-6 ($23.7 million) and Ex. PG&E-4 WP, pp. WP 8-15, lines 41 and 45, and WP 8-25 ($4.7 million).

109/ Ex. DRA-10, p. 7, lines 4-6 and p. 14, lines 10-12, and p. 30, lines 1-5.

removal of $29 million in peak day pricing costs.[110/] In rebuttal testimony, PG&E reduced its forecast for peak day pricing costs by $12.6 million.[111/]

Section 3.5.1(c) provides for a reduction of $10 million for peak day pricing expenses. This provision further states that PG&E shall not request rate recovery of the peak day pricing activities for which expenses were requested in this GRC in another proceeding. Given DRA's and TURN's recommendations to remove these costs from this proceeding and to seek them elsewhere, this provision is supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

b. Other Customer Care Issues (Section 3.5.2)

In addition to the Customer Care revenue requirement issues discussed above, the Settling Parties also agreed to the following non-revenue requirement terms: uncollectibles; audit of SmartMeter accounts; SmartMeter benefits mechanism; SmartMeter consultant costs; DA and CCA fees; reconnection fees; local office hours; NTP&S; and NSF fee.

(1) Uncollectibles (Section 3.5.2(a))

PG&E recommended the adoption of an uncollectibles mechanism that would employ a balancing account, with an $8 million shareholder "deadband" set around a five-year rolling uncollectibles average. PG&E proposed this mechanism in order to promote: (i) better uncollectibles management through times of great economic volatility and (ii) greater utility bill payment and credit policy flexibility in order to assist customers experiencing difficulty in

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110/ Ex. TURN-6, p. 45, lines 14-18, p. 47, lines 3-28 and p. 48, lines 16-18.

111/ Ex. PG&E-18 v4, p. 34-6, lines 17-18 ($3.6 million reduction), p. 36-7, lines 25-26 ($6.2 million reduction) and p. 40-6, lines 8-10 ($2.8 million reduction).

paying their energy bills.[112/] Using recorded data through 2008, PG&E's proposed mechanism would have calculated an uncollectibles factor of 0.002860.

DRA questioned the need for the new mechanism and, instead, recommended a factor of 0.002647 based on a four-year average of historic data from 2004-2007.[113/] Aglet also opposed the new mechanism and recommended a factor of 0.002853 based on an unweighted five-year average of historic data from 2004-2008.[114/]

The Agreement denies PG&E's proposal for a new mechanism and provides for an uncollectibles factor of 0.003105 for the 2011 GRC cycle. Given parties' concerns about the proposal and, at the same time, evidence of increasing uncollectibles due to recent economic events, the denial of PG&E's proposal and the adoption of an uncollectibles factor of 0.003105 are supported by the record. In light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(2) Audit of SmartMeter Accounts (Section 3.5.2(b))

TURN recommended an audit of the SmartMeter program.[115/] Aglet recommended that the Commission undertake a reasonableness review of SmartMeter balancing account entries.[116/] PG&E opposed these recommendations, arguing that given the extraordinary amount of

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112/ Ex. PG&E-4, p. 8-37, lines 26-32.

113/ Ex. DRA-10, p. 35, lines 3-4.

114/ Ex. Aglet-3, p. 2, lines 7-9.

115/ Ex. TURN-6, p. 45, lines 17-21.

116/ Ex. Aglet-3, p. 41, lines 6-17.

information already being provided to the Commission and interested parties, there was no basis for requiring an audit.[117]

Section 3.5.2(b) provides that the Commission's Energy Division will oversee an independent audit of PG&E Smart Meter-related costs, at PG&E's expense, to determine whether costs that should have been recorded in the Smart Meter balancing accounts were instead recorded on other accounts, for example, accounts related to the GRC, demand response, or dynamic pricing programs. The cost to PG&E of the audit is not to exceed $200,000 and is to be recoverable through the SmartMeter balancing accounts. The purpose of the audit is to ensure proper booking and allocation of costs and benefits related to PG&E's SmartMeter program, including the SmartMeter upgrade, and to evaluate whether PG&E's internal cost management guidelines are adequate to ensure that all labor and non-labor costs are properly booked to the SmartMeter balancing accounts. The audit will not include prudency or reasonableness review, or cost-effectiveness of recorded costs. Given TURN's and Aglet's recommendations on this issue, this provision is supported by the record and, in light of the various compromises set forth in the Agreement, this provision is reasonable and in the public interest.

(3) SmartMeter Benefits Mechanism (Section 3.5.2(c))

PG&E has proposed a continuation of the existing balancing account mechanism for costs and benefits for the years 2011-2013, with changes in the benefits recognition mechanism made to reflect: (i) benefits already addressed in other rate recovery mechanisms, (ii) benefits already credited to the balancing account through 2008, (iii) escalation, and (iv) additional benefits not included in the previous mechanism.[118] The net effect of PG&E's adjustments

117/ Ex. PG&E-18 v4, pp. 45-10 to 45-11.

118/ Ex. PG&E-4, p. 13-5, lines 12-16.

produced a monthly activated electric meter credit of $1.8460 and a monthly activated gas meter credit of $0.9110.[119/]

No party has challenged PG&E's proposal to continue the use of the balancing account as a means to return benefits to ratepayers. Parties did provide testimony about the proposed adjustments to the benefits mechanism. In particular, TURN raised questions regarding the escalation level used to adjust the benefits mechanism[120/] and PG&E's proposed removal of "Other Employee Related Costs" from the mechanism.[121/] PG&E addressed these issues in its rebuttal testimony.[122/]

Section 3.5.2(c) provides that the SmartMeter Benefits Realization Mechanism adopted by the Commission in D.06-07-027 and D.09-03-026 should be continued through the 2011 rate case cycle. The per-meter amounts should be adjusted as proposed by PG&E in Table 13-3 of Exhibit PG&E-4 and, in accordance with the removal of meter reading costs from the GRC pursuant to Section 3.5.1(a) of the Agreement, PG&E shall also remove the meter reading savings from the electric and gas crediting mechanism.

Given the evidence provided by the parties in this area and the related sections of the Agreement, the continuation of the mechanism and the adjustment of the per-meter values are supported by the record. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

119/ Ex. PG&E-4, p. 13-11, lines 18-22; and p. 13-14, Table 13-3; as corrected by Tr. Vol. 19, 2298:1-6, PG&E/Corey.

120/ Ex. TURN-6, p. 32, lines 18-23.

121/ Ex. TURN-6, p. 33, lines 13-17.

122/ Ex. PG&E-18 v4, pp. 45-6 to 45-10.

(4) SmartMeter Consultant Costs (Section 3.5.2(d))

In response to the February 16, 2010 ACR in this GRC, PG&E was invited to submit testimony in the GRC with a proposal to address revenue, ratemaking, and other issues related to the costs to be incurred by the Commission's consultant hired to evaluate PG&E's management of the SmartMeter program. PG&E proposed to recover such costs through the previously-authorized cost recovery mechanism for the SmartMeter Program, as set forth in Commission D.06-07-027 and D.09-03-026.[123/]

In accordance with the February 16, 2010 ACR, PG&E filed Advice Letter 3107-G/3643-E on March 30, 2010 proposing to establish a memorandum account to record such consultant costs. No party protested the advice letter and, on July 19, 2010, the advice letter was approved. Similarly, no party in the GRC has contested PG&E's proposed manner for handling such consultant costs.

The Agreement approves PG&E's proposed manner for handling the consultant costs. Given the uncontested evidence provided by PG&E on this issue, the adoption of PG&E's proposal is supported by the record, reasonable, and in the public interest.

(5) DA and CCA Fees (Section 3.5.2(e))

The Commission required PG&E to provide an update to its direct access (DA) service fees in this proceeding.[124/] Accordingly, PG&E proposed to revise certain DA service fees that had not changed since 1999[125/] and to revise fees for similar services provided to Community

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123/ Ex. PG&E-13, p. 2, lines 2-5.

124/ D.07-03-044, *mimeo,* pp. 28-29.

125/ Ex. PG&E-4, p. 14-1, line 19.

Choice Aggregators.[126/] PG&E proposed to make a more thorough review of DA fees in Phase 3 of the proceeding concerning the reopening of DA (Rulemaking 07-05-025).[127/]

PG&E also sought the Commission's approval to cease recording costs and revenues in the Direct Access Discretionary Cost/Revenue Memorandum Account (DADCRMA), pending the determination in Phase 3 of Rulemaking 07-05-025 of future fees, how to treat the balance in the DADCRMA, and possible future uses of that account.[128/]

DACC recommended that PG&E's changes to DA and CCA fees be "conditionally allowed."[129/]

Section 3.5.2(e) provides that DA and CCA fees should be conditionally adopted as proposed. PG&E commits to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA fees. PG&E should be allowed to cease recording costs to the DADCRMA, pending review of the account in the upcoming application.

Given PG&E's and DACC's positions on this issue, the above resolution of this issue is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of this issue as described above is reasonable and in the public interest.

(6) Reconnection Fees (Section 3.5.2(f))

PG&E proposed that the restoration for non-payment fee become $30.00 during regular business hours and $36.00 outside of regular business hours for non-California Alternate Rates for Energy (CARE) customers, and $24.00 during regular business hours and $29.00 outside of

126/ Ex. PG&E-4, p. 14-1, lines 16-18.

127/ Ex. PG&E-4, p. 14-2, lines 2-6.

128/ Ex. PG&E-4, p. 14-2, lines 8-12.

129/ Ex. DRA-10, pp. 50-51; and Ex. DACC-1, p. 16.

regular business hours for CARE customers.[130/] This would be a change from the existing fees of $25.00 during regular business hours and $37.50 outside of regular business hours for non-CARE customers, and $20.00 during regular business hours and $30.00 outside of regular business hours for CARE customers.[131/] TURN was the only party to comment on the proposed changes, recommending that PG&E be prohibited from charging a fee for remote disconnections and reconnections performed via SmartMeter devices.[132/] PG&E responded that the proposed levels are based on blended costs that do not include remote disconnection or reconnection costs with SmartMeter devices. PG&E also responded that it would be administratively difficult and inequitable to charge customers different fees, depending on whether customers had a SmartMeter device already installed.

The Agreement provides that reconnection fees shall not be revised and shall remain at existing levels. Given TURN's concerns about revising reconnection fees in times of declining costs associated with the SmartMeter devices, the denial of PG&E's proposal is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of this issue as described above is reasonable and in the public interest.

(7) Local Office Hours (Section 3.5.2(g))

PG&E proposed to standardize the hours of operation at PG&E's 75 local offices to be from 8:30 a.m. to 5:00 p.m.[133/] PG&E argued that standardizing the offices will allow PG&E to

130/ Ex. PG&E-4, p. 8-3, lines 9-13.

131/ Ex. PG&E-4, p. 8-40, lines 7-13.

132/ Ex. TURN-10, p. 12, line 23 to p. 13, line 5.

133/ Ex. PG&E-4, p. 3-2, lines 3-7. Currently, many offices open at 8:00 a.m., although several open at 9:00 a.m. Ex. PG&E-4, p. 3-9, lines 5-7.

offer much needed time to conduct training and communications from 8:00 a.m. to 8:30 a.m.[134/] DRA opposed PG&E's request, arguing that the PG&E employees should conduct training during "down times" and that the local office hours should be set by the local offices, who know their clientele better than PG&E's general office.[135/] No other party provided testimony on this proposal.

Under the Agreement, PG&E's proposal to adjust local office hours is adopted. Given PG&E's evidence in support of adjusting the office hours, the adoption of PG&E's proposal is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of this issue as described above is reasonable and in the public interest.

(8) Non-Tariffed Products and Services (Section 3.5.2(h))

PG&E proposed that the Commission: (i) adopt a 50/50 positive net revenue sharing mechanism for PG&E's entire catalogue of NTP&S, (ii) approve additional NTP&S categories from other California utility catalogues, and (iii) add a 50/50 positive net revenue sharing mechanism for approved NTP&S that include shareholder capital investments.[136/] This proposal was to be effectuated through expansion of PG&E's current balancing account for NTP&S.[137/]

DRA supported PG&E's proposal to expand PG&E's NTP&S catalogue and to adopt a revenue sharing mechanism for PG&E's NTP&S services, but DRA proposed an alternate revenue sharing formula of 50/50 gross revenue.[138/] TURN recommended denying the proposed

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134/ Ex. PG&E-4, p. 3-2, lines 6-7.

135/ Ex. DRA-10, p. 11, lines 3-10.

136/ Ex. PG&E-4, p. 12-1, lines 21-28.

137/ Ex. PG&E-4, p. 12-12, lines 18-26.

138/ Ex. DRA-10, p. 48, lines 2-5.

expansion of PG&E's NTP&S catalogue and supported DRA's proposed 50/50 gross revenue sharing mechanism.[139/] As a backup proposal, TURN recommended that PG&E could be allowed a 90/10 or 80/20 gross revenue sharing mechanism at the next GRC.[140/]

The Agreement provides that PG&E's proposed expansion of services should be adopted, but PG&E's proposals concerning the 50/50 net revenue sharing mechanism and a sharing mechanism for shareholder capital should not be adopted. The Agreement also provides that the costs and revenues associated with the expansion of services shall be treated on a cost-of-service basis. The Agreement thus adopts a compromise position among those taken by PG&E, DRA, and TURN. Given the positions taken by the various parties, the resolution of these issues as described above is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

(9) Non-sufficient Funds Fees (Section 3.5.2(i))

The Agreement adopts PG&E's proposal to reduce its NSF fee from $11.50 to $9. PG&E's proposal was not contested. Given the uncontested evidence provided by PG&E on this issue, the adoption of PG&E's proposal is supported by the record, reasonable, and in the public interest.

6. Administrative and General Expenses (Section 3.6)

PG&E's Administrative and General (A&G) forecast consists of three cost categories: (1) A&G Study department costs for both the Utility and PG&E Corporation, (2) Corporate Items (*e.g.,* medical benefits, property insurance), and (3) Shared Services. A&G Study department

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139/ Ex. TURN-10, p. 14, lines 22-23 and p. 19, lines 5-6.

140/ Ex. TURN-10, p. 14, line 23 to p. 15, line 2.

costs and Corporate Items are discussed in this subsection 6 of this Motion; Shared Services is discussed in subsection 7, which follows.

a. Revenue Requirement Issues (Section 3.6.1)

PG&E requested Total Company A&G expenses of $971.8 million in 2011, of which $857.1 million is requested for recovery in this GRC.[141/] The Total Company A&G forecast is approximately $130.1 million (15 percent higher in nominal dollars and 8 percent higher in base year dollars) than the 2008 recorded adjusted amount of $841.7 million,[142/] with the increase primarily attributable to forecast increases in employee benefits and liability insurance costs.[143/]

DRA recommended an A&G forecast of $728.9 million.[144/] TURN recommended as a general matter that PG&E's A&G Study department expenses in 2011 be no higher than PG&E's 2010 forecast (plus inflation).[145/] TURN and other parties also took issue with specific A&G costs or practices.

Section 3.6.1 of the Agreement reduces PG&E's GRC-portion of A&G expenses by at least $89 million, consisting in part of the following: (1) $45 million reduction to reflect parties' arguments regarding STIP, including a reduction of $2.8 million in PG&E's STIP request for PG&E Corporation, and (2) $11.5 million reduction to reflect parties' arguments regarding the following departments and areas: Public Affairs ($2.5 million reduction), Corporate Relations

141/ Ex. PG&E-69, p. E-1-1, lines 10 and 20 in "Net Nominal $" section (2011 amounts); and Ex. PG&E-2, p. 7-4, lines 20-25 (2008 amounts). Of the Total Company A&G expenses, approximately 88 percent is requested in this GRC; the remainder is unbundled to Network Transmission and Gas Transmission and Storage. All A&G amounts in this Motion are in nominal Total Company dollars, except where noted.

142/ Ex. PG&E-2, p. 7-14, Table 7-15, line 11.

143/ Ex. PG&E-2, pp. 7-1 to 7-2.

144/ Ex. PG&E-69, p. E-1-1, line 10 in "Net Nominal $" section.

145/ Ex. TURN-1, p. 59.

($2.5 million reduction), and PG&E Corporation ($6.4 million reduction). Section 3.6.1 clarifies that the overall test year revenue requirement increase set forth in the Agreement reflects no reduction to PG&E's test year 2011 forecast of PBOP/LTD expenses.

Given the positions taken by intervenors, the resolution of these issues as described above is supported by the record. Specifically, the overall reduction of $89 million in A&G expenses represents a significant portion of PG&E's A&G request of $130 million over the 2008 recorded adjusted amount. The $45 million reduction to the STIP represents approximately half of the total STIP request.[146/] The reductions to Public Affairs, Corporate Relations, and PG&E Corporation reflect substantial movement by PG&E in those A&G areas that raised the greatest intervenor opposition. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

b. Other A&G Issues (Section 3.6.2)

In addition to the A&G revenue requirement issues discussed above, the Settling Parties also agreed to the following non-revenue requirement terms, described in detail below: (1) PBOP/LTD balancing account, (2) franchise fee factors, (3) Below-the-Line (BTL) guideline revisions, and (4) affiliate employee transfers.

(1) PBOP/LTD Balancing Account (Section 3.6.2(a))

PG&E requested that the Commission adopt its employee benefit plan trust contributions forecast of $163.2 million, which is 33% higher than the 2008 recorded adjusted amount.[147/] PG&E further requested that the Commission adopt a two-way balancing account for PBOP medical and life insurance plans, as well as its LTD plan, consistent with the Commission's

146/ Ex. PG&E-6, p. 16-1, lines 15-17.

147/ Ex. PG&E-6, p. 18-1, lines 26 and 30.

decisions in SCE's 2006 and 2009 GRCs.[148/] DRA opposed PG&E's request for a two-way balancing account but did not otherwise oppose Investments and Benefit Finance's request.[149/]

Section 3.6.2(a) of the Agreement provides that PG&E's current PBOP/LTD balancing account shall remain a one-way account, and that the estimate of total contributions for 2011 to the PBOPs medical and life and LTD trusts will be $163.3 million (total Company before allocation to capital and other non-GRC UCCs). This total amount will also apply to the attrition years. Section 3.6.2(a) also provides that 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 2011 GRC cycle.

Given the positions taken by intervenors, the resolution of these issues as described above is supported by the record. Specifically, the Agreement accepts DRA's recommendation to maintain the balancing account as a one-way balancing account, while accepting PG&E's uncontested request for trust fund contributions. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

(2) Franchise Fees (Section 3.6.2(b))

PG&E forecasted Account 927 franchise fee factors of 0.007593 and 0.009789 for electric and gas, respectively.[150/] Account 927 includes amounts accrued for payments to city and county authorities in compliance with franchise, ordinance, or similar requirements. No party disputed these rates, and PG&E's franchise fee factors are reflected in Section 3.6.2(b) of

148/ Ex. PG&E-6, p. 18-4; *see also* D.06-05-016, *mimeo*, pp. 173-174; and D.09-03-025, *mimeo*, p. 395 (Ordering Paragraph 17).

149/ Ex. DRA-22, p. 15.

150/ Ex. PG&E-2 WP, p. WP 7-41.

the Agreement. Given the lack of opposition to PG&E's request, the resolution of these issues as described above is supported by the record, reasonable, and in the public interest.

(3) PG&E's Below-The-Line Guidelines (Section 3.6.2(c))

SSJID and WEM criticized PG&E's A&G Study department costs on the grounds that PG&E does not properly account for above- and below-the-line activities.[151/] SSJID recommended that the "Commission examine the content and clarity of PG&E's below-the-line accounting guidelines as part of the Order Instituting Investigation that is to accompany this proceeding" to ensure that "ratepayers are not funding activities that should be classified as below-the-line, specifically activities undertaken to oppose CCA or municipalization."[152/] WEM cited to various PG&E activities opposing CCAs and argued that they "should be funded only by shareholders – or not at all."[153/]

Numerous departments have already reduced their GRC requests to account for BTL activities forecast for 2011.[154/] Section 3.6.1 of the Agreement reflects a further reduction in expenses for A&G Study departments that perform BTL work. In addition, Section 3.6.2(c) of the Agreement proposes additional measures that PG&E should take to ensure proper accounting of BTL activities and expenses, including establishment and maintenance of above-the-line and BTL orders in sufficient detail to permit an annual compliance review (and making that annual compliance review available to interested parties in the next GRC); expanding the scope of the BTL guidelines to apply to municipalization initiatives; annual communication and training

151/ Ex. SSJID-1, pp. 71-80; and Ex. WEM-16, pp. 19-21.

152/ Ex. SSJID-1, p. 71, lines 9-13.

153/ Ex. WEM-16, p. 21; *see also id.*, p. 20.

154/ *See, e.g.*, Ex. PG&E-6 WP v1, p. WP 5-11 (Law Department BTL allocation); Ex. PG&E-6 WP v2, p. WP 11-9 (Public Affairs BTL allocation) and p. WP 12-9 (Corporate Relations BTL allocation).

regarding the BTL guidelines; and extending applicability of the BTL guidelines to PG&E Corporation.

Given the recommendations made by SSJID and WEM, the revision of these guidelines as described above is supported by the record. Specifically, the Agreement would strengthen and expand the scope of PG&E's BTL guidelines, thereby alleviating many of the concerns raised by SSJID and WEM. In addition, by requiring PG&E to establish and maintain its orders in sufficient detail to enable an annual compliance review and to share that review with interested parties in the next GRC, the Agreement will improve the transparency of PG&E's BTL accounting for the next GRC. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

(4) Affiliate Employee Transfers (Section 3.6.2(d))

PG&E transferred 183 employees from PG&E Corporation to the Utility to be consistent with PG&E Corporation's focus on the Company and "the reality of the employees' workload. For the vast majority of the transferred employees, virtually all of their workload concerns Company operations and services."[155/] During hearings, CFC took issue with this transfer.[156/]

Section 3.6.2(d) of the Agreement provides that, during the term of this 2011 test year GRC cycle, PG&E shall not accept a permanent transfer of an employee from an affiliate (including PG&E Corporation) unless there is a need for the employee, the employee is fully qualified when compared to other employees and non-employees, and the compensation to be paid the employee is within market range.

155/ Ex. PG&E-6, p. 3-3, line 26 to p. 3-4, line 11.

156/ Tr. Vol. 22, 2691:20-22, CFC/Wodtke.

Given the positions taken by intervenors, the resolution of these issues as described above is supported by the record. Specifically, the Agreement balances CFC's concerns about employee transfers from PG&E Corporation to the Utility, with PG&E's management discretion to adjust its organizational structure without undue and costly procedural hurdles. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

(5) Meals (Section 3.6.2(e))

PG&E does not specifically forecast meals expenses in its 2011 GRC request,[157/] but PG&E did record $15,744,375 in meals expense in 2008, of which approximately $13,495,443 (88%) was included in PG&E's 2011 GRC forecast for expense and capital.[158/]

DRA originally recommended reducing PG&E's GRC forecast by $2,195,271 for meals expense and reducing the associated income tax deductions by $1,097,636.[159/] In supplemental testimony, DRA recommended reducing PG&E's GRC forecast by an additional $10,605,860 for meals expense and an additional $5,302,930 for income tax deductions.[160/] DRA's basis for the reductions was the absence of "a tracking system to show that these expenses are not primarily for entertainment purposes and are justified as a business function for rate recovery."[161/]

157/ Ex. PG&E-18 v1, p. 1-13, lines 30-31.

158/ Ex. PG&E-18 v1, p. 1-13, line 31 to p. 1-14, line 5, and Ex. PG&E-22, p. 22-4, lines 4-6 and fn. 17; *see also* Ex. PG&E-2 WP v2, p. WP 12-399. This figure was prior to PG&E's concession of $441,685 in total, or $389,522 in the GRC.

159/ Ex. DRA-19, p. 11, line 23 to p. 12, line 1.

160/ Ex. DRA-67, p. 1, lines 15-18.

161/ Ex. DRA-67, p. 3, line 19 to p. 4, line 4.

Section 3.6.2(e) of the Agreement requires PG&E to keep records of business reasons for all meals, the number of attendees, and, where practical, a list of attendees, with such additional information to be tracked pursuant to a clear implementation schedule. Given the positions taken by PG&E and DRA, the resolution of these issues as described above is supported by the record. Specifically, the Agreement ensures that PG&E tracks information regarding all meals expenses submitted for reimbursement to enable DRA and other intervenors in the next GRC to determine whether the expenses should reasonably be borne by ratepayers, while giving PG&E adequate time to upgrade its expense reimbursement system to automate collection of such information. Accordingly, the resolution of these issues as described above is reasonable and in the public interest.

7. Shared Services (Section 3.7)

PG&E's Shared Services departments provide wide-ranging services that benefit PG&E's various lines of business. These services can be divided into two broad categories: Information Technology (IT) and General Shared Services, which includes Fleet Services, Supply Chain – Materials Handling, Supply Chain – Sourcing Operations, Real Estate, and Environmental Program.[162/]

PG&E's total IT capital request was $269.8 million.[163/] DRA opposed a significant portion of PG&E's IT capital costs.[164/] PG&E also requested IT expenses of $309.7 million, of

162/ Ex. PG&E-7, p. 1-1, lines 16-18.

163/ Ex. PG&E-69, p. G-7-3.

164/ Ex. PG&E-69, p. G-7-3.

which DRA recommended a $79.6 million reduction.[165/] TURN and Aglet similarly recommended significant reductions to PG&E's IT request.

PG&E's General Shared Services departments requested a total of $252.3 million in 2011 capital costs and $73.1 million in 2011 expense, from which DRA recommended reductions of $87.9 million and $20.6 million, respectively.[166/] Other intervenors also proposed reductions for General Shared Services, most notably TURN.[167/]

In Section 3.7 of the Agreement, the Settling Parties agree that the overall revenue requirement increase for 2011 reduces PG&E's Shared Services forecast by at least $55 million (with an additional $4.6 million reflected in A&G) in test year revenue requirement. This reduction consists in part of (1) a reduction of at least $50 million to resolve DRA's and intervenors' arguments about IT, including TURN's arguments about Business Transformation "Foundational" programs; (2) a reduction of $14.5 million ($4.6 million in expense and $9.9 million in capital for 2011) relating to the costs of sale of 111 Almaden and associated relocation, severance, and retraining costs, subject to additional terms; and (3) a reduction of $4 million to account for an agreement with the California Air Resources Board concerning PG&E's fleet requirements.

Given the positions taken by intervenors, the resolution of these issues as described above is supported by the record. Specifically, the Agreement's reduction of at least $50 million represents a significant reduction to PG&E's IT request, which was the source of substantial

165/ Ex. PG&E-69, p. G-7-9.

166/ Ex. PG&E-69, pp. G-7-12 and G-7-13 (Fleet); Ex. PG&E-69, p. G-7-15 (Materials); Ex. PG&E-69, pp. G-7-20 and G-7-24 (Real Estate); Ex. PG&E-7, p. 5-15, Table 5-1, line 1 (Sourcing); Ex. PG&E-69, pp. G-7-25 and G-7-26 (Environmental).

167/ Ex. TURN-6, p. 2, Table 1, and p. 4.

dispute among PG&E, DRA, TURN, and Aglet. In addition, the $14.5 million reduction for 111 Almaden fairly balances TURN's concerns about the timing and cost of the 111 Almaden relocation project while preserving PG&E's right to seek ratepayer recovery if it elects to dispose of the 111 Almaden building. Finally, the $4 million reduction to account for the California Air Resources Board approval reasonably quantifies the expected cost benefits associated with PG&E's negotiation of an alternate implementation schedule for compliance with the fleet's air quality regulations. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

Section 3.7(b) also addresses PG&E's 111 Almaden facility. PG&E forecast both capital and expense costs to prepare 111 Almaden for sale in order to achieve long-term operating cost reductions and avoid future Real Estate expenditures.[168/] TURN argued that such funding should be rejected "because all costs/expenses necessary for sale should be considered in a Sec. 851 application, and selling [the] building appears imprudent and ill-timed."[169/]

Section 3.7(b) of the Agreement provides that no costs of selling 111 Almaden and no costs associated with relocation, severance, or retraining shall be approved in this GRC. Further, if PG&E sells Almaden, PG&E will file a Section 851 application and may request rate recovery of the costs in the Section 851 application. Given the positions taken by intervenors, the resolution of these issues as described above is supported by the record. Specifically, as explained above, the Agreement's $14.5 million reduction for 111 Almaden fairly balances TURN's concerns about the timing and cost of the 111 Almaden relocation project while preserving PG&E's right to seek ratepayer recovery if it elects to dispose of the 111 Almaden

168/ Ex. PG&E-69, p. G-7-17.

169/ Ex. PG&E-69, p. H-41.

building. In light of the various compromises set forth in the Agreement, the resolution of these issues as described above is reasonable and in the public interest.

8. Depreciation (Section 3.8)

Section 3.8 of the Agreement addresses depreciation and decommissioning issues. As to depreciation expense, this section provides for an overall revenue requirement reduction of no more than $105 million from the level of depreciation expense that would have resulted using the depreciation parameters in PG&E's request. PG&E will implement the reduction by adjustments to net salvage rates. As to decommissioning, this section specifies a reduction to the decommissioning accruals proposed by PG&E of $2 million for the old Humboldt fossil plant and $0.5 million in total for Gateway, Colusa, and New Humboldt.

PG&E presented a detailed depreciation study, proposing updated depreciation parameters (i.e., net salvage rates, average service lives, and mortality curves) in support of its request for depreciation expense.[170/] DRA accepted most of PG&E's proposed depreciation parameters, but disagreed with the size of increases in net salvage rates for six accounts.[171/] TURN, citing the rationale of the last SCE GRC and poor economic conditions, opposed all of PG&E's proposed changes in parameters to the extent they would increase depreciation accruals.[172/] PG&E then submitted rebuttal testimony responding to DRA's and TURN's proposed adjustments, arguing among other things, that without adjustment its accrual rates for net salvage would be lower than those of the other utilities.[173/] Using rate base and capital

170/ Ex. PG&E- 2, Chapters 10 and 11.

171/ Ex. DRA-18, p. 5, lines 4-12 and p. 7, Table 18-6.

172/ Ex. TURN-10, pp. 3-9.

173/ Ex. PG&-18 v2, pp. 4-1 to 4-12; *see* pp. 4-7 to 4-8.

addition assumptions incorporated in PG&E's Application, PG&E calculated that DRA's recommended adjustments to PG&E's depreciation parameters would reduce depreciation expense by approximately $23 million and that TURN's recommendation would result in a reduction of approximately $200 million.[174/]

In consideration of the record on this issue, Section 3.8 is a reasonable compromise of the parties' respective litigation positions to adjust PG&E's proposed net salvage rates to result in a revenue requirement reduction of no more than $105 million. The depreciation parameters used to reflect this compromise, which include all of the modifications proposed by DRA, are set forth in Appendix C to the Agreement.

As to decommissioning, PG&E proposed decommissioning accruals of approximately $40.8 million, including $19.2 million for the old fossil plants at Humboldt Bay and $2.5 million for the new fossil units. In support of these accruals, PG&E provided decommissioning studies and described the methodology supporting the accruals.[175/]

DRA recommended lowering the contingency for fossil decommissioning forecast from 25% to 10% resulting in approximately a $4 million revenue requirement decrease for these plants.[176/] TURN also recommended reductions in PG&E's proposed accruals. TURN disagreed with scrap metal salvage assumptions included in the study, PG&E's use of a 25% cost contingency, and other assumptions.[177/] TURN also disagreed with PG&E's method of amortizing decommissioning costs for the new plants on a straight line basis, proposing

174/ Ex. PG&E-18 v2, pp. 4-2 to 4-3.

175/ Ex. PG&E-2, pp. 10-21 to 10-23; Ex. PG&E-2 WP, pp. WP 10-401 to 10-404.

176/ Ex. DRA-9, p. 31, lines 1-2.

177/ Ex. TURN-1, pp. 53-58.

adjustments that would tend to equalize accruals in real dollars.[178/] Taken together, TURN's adjustments reduced PG&E's proposed decommissioning expense by $3,975,000 (i.e., $1.171 million at the three new fossil plants and $2.804 million at the Humboldt Bay site).[179/] In response to DRA's and TURN's proposed reductions, PG&E then submitted rebuttal testimony.[180/]

The Settling Parties agree that the Settlement's adoption of a $2.5 million annual reduction in decommissioning accruals represents a reasonable compromise of their respective litigation positions.

9. Capital-Related Costs, Including Rate Base and Method for Income Taxes (Section 3.9)

a. $35 million adjustment (Section 3.9(a))

Section 3.9(a) provides that the agreed-upon test year revenue requirements for 2011 include a reduction of $35 million to reflect (1) capital expenditure reductions for New Business/WRO; (2) recalculation of 2011 rate base using updated estimates of bonus depreciation-related deferred tax balances to reflect 2008 and 2009 bonus depreciation; and (3) resolution of issues raised by TURN regarding income taxes, customer deposits, and materials and supplies.[181/]

The principal dollar amounts incorporated in the $35 million figure involved disputes between PG&E and TURN involving income taxes (including deferred taxes) and customer

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178/ Ex. TURN-1, pp. 56-57.

179/ Ex. TURN-1, p. 53.

180/ Ex. PG&E-18 v2, pp. 4-8 to 4-11; Ex. PG&E-18 v5, pp. 49-12 to 49-18.

181/ The Agreement provides that the amount corresponding to the $35 million in PG&E's 2011 gas transmission and storage rate case is $3 million.

deposits. These issues are discussed further below. Less than $10 million in test year revenue requirements was placed in dispute relating to DRA's adjustments to PG&E's forecasts of capital expenditures associated with New Business/WRO and to DRA's and TURN's adjustments relating to the level of materials and supplies inventory.[182/] Given the record evidence, it is appropriate that the Settling Parties embedded, within this $35 million figure, compromises associated with forecasts of capital costs involving New Business/WRO and materials and supplies.[183/]

TURN raised two income tax policy issues, proposing that forecasted tax deductions should be increased to reflect the special deductions for common stock dividends paid by PG&E Corporation to participants in PG&E's 401(k) plan (converting to a revenue requirement reduction of approximately $32 million) and deductions on interest paid by PG&E Corporation (converting to a revenue requirement adjustment of approximately $25 million, total company).[184/] TURN also raised a policy issue associated with customer deposits, proposing that they be used to reduce working cash (which converted to a revenue requirement adjustment of approximately $19 million).[185/] PG&E responded extensively to these policy issues, raising factual and policy based objections to TURN's positions.[186/] The Settling Parties agree that they have reasonably compromised their litigation positions within the $35 million figure. The Settling Parties further agree that the underlying policy issues shall remain unresolved; that this

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182/ Ex. DRA-8, pp. 15-18; Ex. DRA-17, pp. 28-30; and Ex. TURN-1, p. 92.

183/ Ex. DRA-8, pp. 15-18; Ex. PG&E-18 v3A, pp. 16-3 to 16-7; Ex. PG&E-18 v7, Ch. 71; and Ex. TURN-1, p. 92.

184/ Ex. TURN-1, pp. 84-86.

185/ Ex. TURN-1, pp. 98-104.

186/ Ex. PG&E-18 v2, Chs. 6B, 7, 11A, 11B, and 11C.

GRC shall not address or seek to resolve these issues, consistent with the Commission's rationale in D.09-06-052; and that any subsequent resolution of these issues (e.g., in another GRC) shall not impact the revenue requirements of PG&E for this GRC cycle.[187/]

On forecasts of tax expense for ratemaking purposes, TURN disagreed with PG&E's test-year estimate of Federal and State repair allowance, and proposed a revenue requirement reduction of approximately $5.6 million, believing the deduction is likely to be greater than was forecasted by PG&E. In addition, TURN cited a PG&E data response indicating PG&E would claim more bonus depreciation than it forecast on account of 2008 and 2009 Federal stimulus legislation.[188/] TURN recommended that this additional bonus depreciation should be reflected for ratemaking purposes, resulting (together with revised forecasts of the Manufacturers Tax Deduction) in a revenue requirement reduction of at least $12 million.[189/] PG&E agreed with TURN, but only if the Commission consistently trued-up additional actual capital spending for 2009 to the forecast.[190/] The Settling Parties agree that these two tax forecasting issues are also reasonably compromised within the overall $35 million reduction.

b. Nuclear Fuel (Section 3.9(b))

Until PG&E's 2003 GRC, rate recovery for the Diablo Canyon Power Plant was not governed by traditional cost of service ratemaking.[191/] Thus, PG&E had not been subjected to

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187/ D.09-06-052, *mimeo*, p. 14; Finding 27 ("Several of the unresolved issues identified by the Settling Parties do not need to be decided in order to approve the settlements. These include the following: depreciation expense, funding for incentive compensation, working cash expense, employee stock ownership plan deduction"); Conclusion of Law 5 ("It is not necessary to resolve every issue left unresolved by the settling parties in order to approve the settlements").

188/ Ex. TURN-91, p. 2.

189/ Ex. TURN-13, pp. 76-77.

190/ Ex. PG&E-18 v2, p. 6A-10, line 28 to p. 6A-11, line 3.

191/ Ex. PG&E-18 v2, p. 11A-7, lines 3-5.

recovery rules for nuclear fuel that had applied to other utilities. In PG&E's 2003 GRC, PG&E included nuclear fuel in rate base without objection.[192/] In connection with a settlement of PG&E's 2007 GRC, PG&E agreed to remove nuclear fuel from rate base and instead obtain recovery through the ERRA account.[193/] Due principally to very recent changes in the financial markets and changes that have increased PG&E's demand for short-term credit, PG&E again proposed to include nuclear fuel in rate base.[194/]

DRA and EPUC, however, recommended that the carrying cost for nuclear fuel should continue to be recovered in ERRA proceedings using short-term interest rates as a carrying cost.[195/] DRA's position was based on a series of cases involving SCE, including D.06-05-016.[196/] EPUC's position was based on the cases involving SCE, PG&E's ability to "continue operations with the carrying cost for nuclear fuel inventory determined to be collected through the ERRA at the short-term interest rate" during the financial market turmoil, and the impact on bundled ratepayers of PG&E's proposal.[197/]

Section 3.9(b) provides that PG&E's nuclear fuel and fuel inventory would continue to be excluded from rate base, that revenue requirements in this case would be reduced by $49 million and that the costs of this fuel would be recovered through the ERRA at a carrying cost reflecting short-term interest rates. As part of the overall Settlement, it is appropriate, reasonable and in

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192/ Ex. PG&E-18 v2, p. 11A-7, lines 5-6.

193/ Ex. PG&E-18 v2, p. 11A-7, lines 7-13.

194/ Ex. PG&E-18 v2, p. 11A-7, line 20 to p. 11A-8, line 11.

195/ Ex. DRA-20, pp. 3-7; and Ex. EPUC-27, pp. 3-7.

196/ Ex. D.06-05-016, *mimeo*, p. 274.

197/ Ex. EPUC-27, pp. 3-7.

the public interest that the Settling Parties agree to exclude nuclear fuel and fuel inventory from rate base and that these costs would be recovered through the ERRA at a carrying cost reflecting short-term interest rates.

c. MRTU-Related Costs (Section 3.9(c))

PG&E originally sought approximately $20 million in MRTU capital-related revenue requirements.[198/] DRA recommended that such costs be removed from the GRC.[199/]

Section 3.9(c) of the Agreement removes all of PG&E's MRTU-related revenue requirements from its GRC request, totaling $20 million in 2011. This provision further provides that for the duration of this GRC cycle, PG&E shall seek recovery of MRTU-related costs in ERRA proceedings or other proceedings if so directed by the Commission. Given the positions taken by DRA, the removal of these costs from the GRC is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of this issue as described above is reasonable and in the public interest.

d. Rate Base Treatment of Retired Electric and Gas Meters (Section 3.9(d))

As a result of PG&E's SmartMeter program, PG&E is retiring the old meters as they are replaced by new, SmartMeter devices. TURN recommends that PG&E's remaining unrecovered investment in retired electric and gas meters be removed from rate base, thus earning no return.[200/] PG&E provided rebuttal opposing TURN's position.[201/]

198/ Ex. PG&E-2 WP, Vol. 1, p. 18-492, line 3, col. O.

199/ Ex. DRA-15, pp. 34-35.

200/ Ex. TURN-10, p. 9.

201/ Ex. PG&E-18 v2, pp. 8-13 to 8-14.

The Settling Parties agree that the revenue requirements included in the Settlement Agreement have been reduced by $44 million, incorporating the assumption that the unrecovered costs of the electromechanical meters have been excluded from rate base. However, the Settling Parties have also agreed that this issue will be litigated and that should PG&E prevail in its position that these costs should remain in rate base, the revenue requirements adopted in this GRC from the Settlement would be increased accordingly (i.e., by the $44 million, if PG&E prevails in its argument that the entire unrecovered cost of the retired meters should remain in rate base), effective January 1, 2011.

e. Rate Base and Capital Expenditure Levels (Section 3.9(e))

The tables presented in this section of the Settlement Agreement are derived from settlement provisions discussed elsewhere in this Motion. The Settling Parties agree this derivation is reasonable and should be adopted.

10. Balancing Accounts (Section 3.10)

PG&E recommended new balancing account mechanisms for health care costs; New Business/WRO and Rule 20A work; renewable energy projects; uncollectibles; emergencies and catastrophic events; and RD&D expenses. PG&E proposed these new accounts to address special circumstances where it believed such accounts were in the interests of both shareholders and ratepayers:

- <u>Two-way balancing accounts where the future costs are highly uncertain and outside the utilities' control</u>. These proposed balancing accounts (or balancing account changes) include Health Care Costs (that are subject to government actions and cost increases entirely outside PG&E's control); Electric Emergency Response; and Uncollectible Accounts Expense (which depends increasingly on policy decisions of the Commission, and less on PG&E initiated collection activities).

- One-way balancing accounts, where the costs are outside of PG&E's control, but where the upside cost estimate may be estimated with reasonable certainty. This was proposed by PG&E for a single account: Work Required by Others. By definition, PG&E argued it had little control of these costs which depend entirely on an uncertain forecast of economic conditions.
- One-way balancing accounts for programs where the costs are project-specific. PG&E proposed one-way accounts to address situations where funds would be spent only if the Commission believed the programs should be funded. Any funds that are not spent for the express purpose designated will be returned to customers. The accounts proposed under this rationale were for Research Development and Demonstration and Renewable Resource Development.[202/]

DRA, Aglet, and CFC objected to these new accounts, as shown in the table below:

202/ Ex. PG&E-18 v8, pp. 77-3 to 77-9.

PACIFIC GAS AND ELECTRIC COMPANY
2011 GENERAL RATE CASE
ISSUE SUMMARY
(2011 REQUEST)[203/]

Line No.	Item at Issue	DRA	AGLET	CFC
1	Health Care Costs BA – 2-Way	No	No	No
2	Uncollectible Accounts Expense BA – 2-Way	No or 2011-2013 Time Period	No	No
3	Electric Emergency Recovery BA – 2-Way	No	No	No
4	RD&D Costs BA – 1-Way	Yes	No	No
5	New Business/WRO/Rule 20A BA – 1-Way	No	No	No
6	Renewable Energy Costs BA – 1-Way	Yes – 2 Accounts	No	No

Aglet argued that these new balancing accounts would shift risk to customers without compensation, reduce incentives, and cause accounting and auditing difficulties.[204/] CFC and Aglet also argued that they would inappropriately shelter costs from GRC-level scrutiny.[205/] Finally, CFC argued these balancing accounts were inconsistent with regulatory policy.[206/] PG&E responded to these arguments in rebuttal.[207/]

In consideration of the overall Settlement, PG&E has agreed that its proposal for new balancing accounts should not be adopted.

11. Attrition Years (Section 3.11)

Section 3.11 of the Agreement provides that PG&E's annual attrition adjustment for 2012 and 2013 will be fixed dollar amounts of $180 million in 2012, and $185 million in 2013, subject

203/ Ex. PG&E-18 v8, p. 77-3.

204/ Ex. Aglet-3, pp. 54-57.

205/ Ex. Aglet-3, p. 56; and Ex. CFC-1, pp. 27-33.

206/ Ex. CFC-1, pp. 27-33.

207/ Ex. PG&E-18 v8, pp. 77-3 to 77-9.

to limited adjustments for specified exogenous changes described in Section 3.11.3. As provided in Appendix B to the Settlement Agreement, the 2012 increase comprises $123 million for electric distribution, $35 million for gas distribution, and $22 million for electric generation; and the 2013 increase comprises $123 million for electric distribution, $35 million for gas distribution, and $27 million for electric generation.

PG&E proposed a post-test year ratemaking mechanism composed of escalation of operating expenses reflecting cost increases for the labor, goods, and services that PG&E purchases (including escalation of employee health care benefits costs) and additional capital-related costs due to growth in rate base based on forecasted plant additions.[208/] PG&E's attrition method would use annual advice filings and separately computes expense and capital adjustments.[209/] Based on its method, PG&E projected attrition increases of $181 million in 2012 and $223 million in 2013 for electric distribution, $49 million in 2012 and $64 million in 2013 for gas distribution, and $33 million in 2012 and $47 million in 2013 for electric generation.[210/] This would result in total attrition increases of $263 million and $334 million for 2012 and 2013, respectively.

Regarding attrition, DRA's primary recommendation used a Consumer Price Index-based approach that would permit PG&E to file an advice letter seeking attrition relief that DRA estimated would result in increases of $63 million and $58 million for electric distribution in 2012 and 2013, respectively; $21 million and $20 million for gas distribution in 2012 and 2013, respectively; and $31 million and $28 million for electric generation in 2012 and 2013,

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208/ Ex. PG&E-1, p. 1-18, lines 3-14.

209/ Ex. PG&E-1, p. 1-2, lines 1-5.

210/ Ex. PG&E-69, p. F-1.

respectively.[211/] This would result in total attrition increases of $115 million and $106 million for 2012 and 2013, respectively. DRA cited various Commission decisions adopting settlements, as well as economic conditions, in support of its recommendation.[212/] Aglet concurred in DRA's attrition proposal and provided additional support for it, stating that Aglet supported fixed percentage increases because they provided PG&E certainty about attrition year revenues for planning purposes.[213/]

DRA's alternative recommendation (provided in the event the Commission chose to rely on a proposal similar to the PG&E method) would separately compute expense and capital adjustments, and, therefore, result in additional attrition increases above those in DRA's primary recommendation. However, under this alternative, DRA would still limit PG&E's wage increase, medical cost increases, and capital spending increases during the attrition period below those proposed by PG&E.[214/] Aglet opposed this alternative recommendation.[215/] CFC argued that, in light of the economy, PG&E should not be entitled to any attrition adjustment.[216/]

PG&E responded to the objections to its attrition proposal in rebuttal testimony, citing the reasoning of D.06-05-016, including its discussion of capital-related cost increases resulting from increasing net plant, in support of using a traditional attrition approach.[217/] PG&E also

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211/ Ex. DRA-21, p. 3.

212/ Ex. DRA-21, pp. 11-13; Tr. Vol. 29, 3841:27 to 3842:5 DRA/Tang.

213/ Ex. Aglet-3, p. 61.

214/ Ex. DRA-21, pp. 15-20.

215/ Ex. Aglet-3, p. 61, lines 3-9.

216/ Ex. CFC-1, pp. 13-14.

217/ Ex. PG&E-18 v8, pp. 79-4 to 79-10.

provided support for its proposals to reflect increases in capital spending, wages, and medical costs.[218/]

The Agreement adopts fixed attrition increases of $180 million and $185 million for 2012 and 2013, respectively, to be implemented by advice letter. The Settling Parties also have agreed that PG&E's attrition mechanism will reflect exogenous changes, limited to five factors (postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, *ad valorem* tax changes), with a $10 million deductible amount applicable to each factor each year. PG&E's attrition requests would yield base revenue requirement increase of 3.96% in 2012 and 4.83% in 2013. DRA's primary recommendation, endorsed by Aglet, would produce corresponding increases of 2.00% in 2012 and 1.80% in 2013. The Agreement will yield increases of 3.01% in 2012 and 3.00% in 2013, before consideration of revenue requirement issues that are deferred to future years or other proceedings. The Settling Parties agree that this outcome represents a reasonable compromise of their respective litigation positions.

12. Accounting and Other Items (Section 3.12)

a. Revenues at Present Rates (Section 3.12(a))

PG&E submitted its computation of revenues at present rates that is based on previously authorized CPUC jurisdictional revenue requirements.[219/] The computation is largely mechanical and was non-controversial. The Parties agree that the revenues at present rates shown in the first column of Table 1-1 of the Joint Comparison Exhibit (entitled "2011 Authorized") are reasonable and should be adopted.[220/]

218/ Ex. PG&E-18 v8, Ch. 79.

219/ Ex. PG&E-2, Ch. 15 and Ch. 16.

220/ Ex. PG&E-69, p. 1-5.

b. Other Operating Revenue (Section 3.12(b))

PG&E requested that the Commission adopt its 2011 expense forecast of electric and gas distribution OOR of $97.9 million and $22.9 million, respectively, and the electric generation forecast of $11.6 million, which reside in various MWCs.[221/] DRA recommended an overall increase in OOR of $0.911 million for electric and $0.208 for gas for 2011 based on use of 2009 recorded data as opposed to 2008 recorded data for selected FERC accounts.[222/] TURN recommended an overall increase of $1.5 million in electric OOR for 2011 based on pole restoration for poles PG&E jointly owns with Verizon and other joint-pole owners, and an additional adjustment based on PG&E's Non-Tariffed Products and Services proposal.[223/]

Section 3.12(b) of the Agreement provides that CPUC-jurisdictional Other Operating Revenues (OOR) shall be $97.9 million for electric distribution, $22.9 million for gas distribution and $11.6 million for electric generation. Given the evidence provided by PG&E on this issue, the adoption of PG&E's proposal is supported by the record. In light of the various compromises set forth in the Agreement, the resolution of this issue as described above is reasonable and in the public interest.

c. Cost of Capital (Section 3.12(c))

The Settlement provides that revenue requirements to reflect future cost of capital proceedings shall be calculated using the adopted 2011 rate base amounts. This provision is

221/ Ex. PG&E-2, p. 17-1, lines 25-28.

222/ Ex. DRA-3, pp. 11-12; Ex. CFBF-1, p. 3.

223/ Ex. TURN-3, pp. 21-24; Ex. TURN-10, p. 14, line 23.

reasonable and should be adopted because it is consistent with the treatment of PG&E in past GRCs and the practice of the Commission in implementing cost of capital proceedings.[224/]

d. Capitalization Rates (Section 3.12(d))

Since its 1999 GRC, PG&E has conducted a comprehensive study of its A&G expenses to forecast such expenses for the GRC. The methodology for PG&E's 2011 A&G Study is described in detail in PG&E's testimony and workpapers. PG&E proposed a capitalization rate of 24.65% for STIP; 38.41% for Severance, Workers' Compensation, Remaining Vacation, and Pension and Benefits; and 9.3% for Third Party Claims payments.[225/] DRA agreed with all of these rates except for Third Party Claims.[226/]

Section 3.12(d) of the Agreement provides that the revenue requirement adopted by the Agreement incorporates PG&E's proposed capitalization rates. Given the parties' testimony in this area, including the fact that PG&E's proposals were unopposed with the sole exception of Third Party Claims, the resolution of these issues as described above is supported by the record, reasonable, and in the public interest.

e. Software Capitalization Threshold (Section 3.12(e))

For 2011 and forward, PG&E proposed a reduction to the application software threshold from $5 million to $1 million.[227/] This change was not opposed. The Settling Parties agree this change is reasonable and should be adopted.

224/ See D. 07-12-049, *mimeo*, p. 47 and D. 08-05-035.

225/ Ex. PG&E-69, p. E-4, lines 1, 4 and 5.

226/ Ex. DRA-13, p. 7, line 20 to p. 8, line 3.

227/ Ex. PG&E-8, p. 2-4, lines 16 to p. 2-5, line 2.

f. Capitalization Factors for A&G Study Departments (Section 3.12(f))

PG&E proposed capitalization factors for A&G Study departments of 7.33% for labor and 4.44% for materials.[228/] DRA recommended factors of 11.12% for labor and 11.59% for materials based on the capitalization rates from PG&E's 2007 GRC A&G Study.[229/] The proposed capitalization factors for A&G Study departments reflect the capitalization rate adjustments agreed to by PG&E for Safety Engineering and Health Services[230/] and PG&E filed errata for two other departments.[231/] Otherwise, PG&E disagreed with DRA's recommendation.

Section 3.12(f) of the Agreement adopts PG&E's proposed capitalization factors for A&G Study departments. Given the parties' testimony on this issue, including the fact that PG&E agreed to make adjustments to its original capitalization factors, the resolution of this issue as described above is supported by the record, reasonable, and in the public interest.

g. Allocation Factors for Non-Utility Activities (Section 3.12(g))

PG&E proposed the following allocation factors associated with non-utility activities: PG&E Corporation corporate items of 32.68%, below the line for workers' compensation and benefits of 0.31%, and non-utility affiliates for benefits of 0.06%.[232/] PG&E's proposal was unopposed. Section 3.12(g) adopts the unopposed allocation factors described above. Given the lack of opposition to PG&E's proposed factors, the resolution of this issue as described above is supported by the record, reasonable, and in the public interest.

228/ Ex. PG&E-69, p. E-4, lines 2-3.

229/ Ex. DRA-13, p. 7, lines 15-19.

230/ Ex. PG&E-18 v6, p. 52-3, lines 8-10, and p. 52-12, lines 18-28.

231/ Ex. PG&E-18 v6, p. 52-19, Table 52-4.

232/ Ex. PG&E-2 WP, p. WP 7-49.

h. Common Cost Allocation Factors (Section 3.12(h))

Residual common plant and A&G (i.e., common costs that are not direct assigned) are allocated to UCCs based on labor ratios, consistent with Commission findings in D.97-08-056.[233/] PG&E's proposed allocation percentages were based on 2008 recorded adjusted labor and were not contested. These ratios are set forth in Appendix D. The Settling Parties agree these percentages are reasonable and should be adopted.

i. Allocation to Unbundled Cost Categories (Section 3.12(i))

PG&E unbundles its common A&G expenses into five major UCCs using Operations and Maintenance (O&M) labor ratios.[234/] No party disputed PG&E's unbundling methodology. Section 3.12(h) of the Agreement adopts allocation factors by reference to Appendix D.

Consistent with past practice, Section 3.12(i) of the Agreement confirms that the A&G expenses allocated to the UCCs adopted in this 2011 GRC shall be used in determining the A&G expenses in related proceedings in 2011 and future years until PG&E's next test year GRC. Given the lack of opposition to PG&E's methodology, the resolution of this issue as described above is supported by the record, reasonable, and in the public interest.

j. MOU with Disability Rights Advocates (Section 3.12(j))

DisabRA and PG&E entered into a Memorandum of Understanding (MOU)[235/] as a reasonable accommodation of DisabRA's and PG&E's respective interests in this GRC. The MOU effects a modest increase to PG&E's revenue requirement and one that is well below the

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233/ Ex. PG&E-2, pp. 9-10 to 9-11.

234/ Ex. PG&E-2, p. 7-4, lines 7-25.

235/ Ex. PG&E-16, Attach. A.

concessions made by PG&E through rebuttal and errata.[236/] Specifically, through the MOU and the joint testimony submitted by DisabRA and PG&E, the parties advocate the following increases in PG&E's forecast: (1) a total increase of $0.67 million in expense for various MWCs and Provider Cost Centers and (2) an increase of $0.04 in capital expenditures in 2011 for MWC 87.[237/] No other party has filed any testimony or otherwise raised any issue or concern in this area.

Section 3.12(j) of the Agreement provides that the MOU shall be approved and that the costs set forth in Section D of Exhibit PG&E-16 are included in the overall revenue requirement reflected in the Agreement. Given the lack of opposition to the MOU, the resolution of this issue as described above is supported by the record, reasonable, and in the public interest.

k. Total Factor Productivity Studies (Section 3.12(k))

Aglet proposed eliminating the requirement that PG&E prepare a total factor productivity (TFP) study as part of its GRC applications.[238/] Aglet states that it has participated in many general rate cases and has yet to read a TFP study that was of any practical value.[239/] PG&E did not object to Aglet's proposal.[240/] The Settling Parties agree that Aglet's proposal to eliminate the TFP requirement for PG&E is reasonable and should be adopted by the Commission.

236/ Ex. PG&E-16, p. 12, lines 1-13.

237/ Ex. PG&E-16, p. 11, Table 1 and p. 12, lines 1-9.

238/ Ex. Aglet-3, pp. 51-52.

239/ Ex. Aglet-3, pp. 51-52.

240/ Ex. PG&E-18 v8, p. 73-15, lines 18-24.

l. Long-Term Incentives (Section 3.12(l))

In PG&E's test year 2003 GRC, the Commission required in D.04-05-055 that PG&E include information about long-term incentives in the Total Compensation Study, even though the cost of such incentives is recorded BTL and not included in the GRC request. In its 2011 GRC application, PG&E requested to be relieved of this requirement in future GRCs.[241/] PG&E's request was unopposed.

Section 3.12(l) of the Agreement provides that PG&E shall be relieved of this requirement in future Total Compensation Studies. Given the lack of opposition to PG&E's request, the resolution of this issue as described above is supported by the record, reasonable, and in the public interest.

m. RO Model (Section 3.12(m))

DRA recommended that the Commission order PG&E to modify its current RO model to meet the needs of the Commission and that this be completed, demonstrated, and submitted to the Commission at least six months prior to the Notice of Intent (NOI) in its next GRC.[242/] PG&E agreed that the RO should be modified but wanted a more formalized procedure to assure that, with best efforts at making improvements, its RO model will be accepted on a timely basis by DRA.[243/]

Section 3.12(m) of the Agreement provides that prior to submission of an RO model in PG&E's NOI to file its next GRC application, DRA and PG&E shall review PG&E's Excel-based RO model used for the 2011 GRC, and jointly determine what changes should be made to

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241/ PG&E Application, p. 15; Ex. PG&E-8, pp. 11-1 to 11-2, and p. 11-3, Table 11-1, Line 6.

242/ Ex. DRA-2, p. 4, lines 6-9.

243/ Ex. PG&E-18 v2, Ch. 10.

enhance the model. Furthermore, this provision states that PG&E shall develop a draft of the RO that is Excel-based, consistent with law, and shall not require any manual movement or copying of data or files from one section of the model to another. Prior to DRA's initial review of the RO model, PG&E shall also provide DRA with the appropriate user manuals for the model.

Section 3.12(m) also provides that the new PG&E RO model should incorporate improved logic and structure and prescribes a timeline for development and submission of the model. To ensure PG&E has adequate time to enhance the model for submission in the NOI for its 2014 GRC application, PG&E and DRA shall attempt to reach agreement on all changes by June 1, 2011. PG&E shall also provide DRA with a fully functional version of the model six months prior to the presentation of PG&E's NOI, with comments due back from DRA within two months.

Given the parties' testimony in this area, the issues associated with the development and submission of the RO model in this GRC, and PG&E's and DRA's collective desire to avoid similar problems in the future, this provision of the Agreement is supported by the record, reasonable, and in the public interest.

n. Presentation of Cost Savings (Section 3.12(n))

CFC, among other parties, expressed concern that PG&E had not included in its forecast certain cost savings that were likely to accompany cost increases.[244/] PG&E responded to CFC's and others' concerns in its rebuttal testimony, indicating in some instances that cost savings were not expected or identifying areas in the record where cost savings could be found.

Section 3.12(n) addresses the concern raised by CFC. Specifically, it provides that in future GRCs, PG&E will not add a new type of cost to the revenue requirement without

244/ Ex. CFC-1, p. 14, line 19 to p. 23, line 20; Ex. PG&E-69, p. H-14.

estimating and including in the revenue requirement the cost savings to be achieved by the new type of cost or an explanation of the reasons there will be no cost savings. Given the concerns raised by CFC and the other intervenors, this provision is supported by the record, reasonable and in the public interest.

o. Reasonableness of Showing (Section 3.12(o))

Section 3.12(o) provides that PG&E shall be required to affirmatively establish the reasonableness of all aspects of its next GRC application. For purposes of this current rate case, the Settling Parties agree that opinion testimony should have a factual foundation.

In SCE's recent GRC, the Commission stated that SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application.[245/] Similarly, the judiciary has stated that expert testimony must have a factual foundation.[246/] Accordingly, Section 3.12(o) is consistent with law, reasonable, and in the public interest.

p. AFUDC for Transform Operations Projects (Section 3.12(p))

TURN identified that PG&E had suspended development of ten software projects (called "Transform Operations" and initiated under Business Transformation), and argued that PG&E should have also suspended AFUDC accruals on them.[247/] As part of the compromises made in reaching an overall settlement, PG&E has agreed to suspend these AFUDC accruals and that, should it request recovery of these software costs, not include AFUDC starting on dates identified in TURN's testimony until spending resumes. Given the overall settlement, the Settling Parties agree these adjustments should be found reasonable and in the public interest.

245/ D.09-03-025, *mimeo*, p. 8.

246/ Pacific Gas & Electric Co. v. Zuckerman, 189 Cal. App. 3d 1113 (1987).

247/ Ex. TURN-1, pp. 105-107.

q. Economic Impacts of Capital Spending (Section 3.12(q))

PG&E provided direct testimony on the economic impacts of capital spending.[248/] Aglet, SSJID, and Greenlining took issue with PG&E's testimony in this area, raising a variety of substantive concerns over PG&E's job creation study.[249/] PG&E's rebuttal testimony addressed parties' concerns and explained that the testimony was not meant to justify PG&E's requested spending level, but rather to translate the forecasted spending into an estimate of the number of jobs that would be created by the capital spending.[250/]

Section 3.12(q) withdraws PG&E's testimony on the economic impacts of its capital spending during the test year 2011 GRC cycle. Given the concerns raised by intervenors and PG&E's explanation that such testimony was not meant to justify PG&E's requested spending level, the withdrawal of this testimony is supported by the record, reasonable, and in the public interest.

r. Withdrawal of Certain Intervenor Recommendations (Section 3.12(r))

As explained in Section V.B. of this Motion, Section 4.13 provides that unless otherwise provided in the Agreement, all proposals and recommendations by the parties, including, but not limited to, those set forth in the Joint Comparison Exhibit, are either withdrawn or considered subsumed without adoption by the Agreement.[251/] In addition, Section 3.12(r) withdraws the following Aglet recommendations and proposals:

248/ Ex. PG&E-1, Appendix 2A.

249/ Ex. Aglet-3, p. 1, lines 25-27, p. 17, line 13 to p. 19, line 24; Ex. SSJID-1, pp. 61-70; Ex. Greenlining-2, pp. 2-22.

250/ Ex. PG&E-18 v1, p. 1-19, lines 27-29.

251/ The specific mention of items withdrawn in Section 3.12(r) is done at the request of the withdrawing party. If the Agreement was otherwise silent regarding these recommendations and proposals, they would be

- Aglet's recommended disallowance for Reserve and Efficiency Funds;[252/]
- Aglet's recommendation regarding sunk benefits in future Diablo Canyon cost benefit studies;[253/]
- Aglet's recommendation to treat Diablo Canyon critical spares as plant held for future use;[254/]
- Aglet's proposal to incorporate additional labor productivity factors into test year 2011 revenue requirements that are derived from base year 2008 recorded expenses;[255/] and
- Aglet's recommendation for a Commission investigation into PG&E's procurement of information technology products and services.[256/]

PG&E opposed each of these recommendations. In light of the various compromises set forth in the Agreement, the withdrawal of Aglet's recommendations and proposals is supported by the record, reasonable, and in the public interest.

s. ESC Issues (Section 3.12(s))

In its testimony, ESC made various recommendations concerning outsourcing and PG&E's need to develop a workforce plan to address projected workload, employee attrition, and knowledge transfer.[257/]

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withdrawn or considered subsumed through the effect of Section 4.13.

252/ Ex. Aglet-3, p. 1, line 22, p. 14, line 1 through p. 17, line 12; Ex. PG&E-69, p. H-2, line 4.

253/ Ex. Aglet-3, p. 3, line 1, p. 47, line 2 to p. 48, line 20; Ex. PG&E-69, p. H-3, line 13.

254/ Ex. Aglet-3, p. 3, line 11, p. 49, line 16 to p. 50, line 5; Ex. PG&E-69, p. H-4, line 15.

255/ Ex. Aglet-3, p. 3, line 18, p. 52, line 5 to p. 53, line 15; Ex. PG&E-69, p. H-4, line 17.

256/ Ex. Aglet-1, p. 6, line 3, p. 13, line 5 to p. 15, line 4; Ex. PG&E-69, p. H-5, line 22.

Section 3.12(s) of the Agreement provides that PG&E and ESC have resolved certain issues associated with outsourcing and that in PG&E's next GRC, PG&E will submit testimony on the status of its workforce training programs, its hiring in advance of employee attrition at Diablo Canyon Power Plant, and its request for additional hydroelectric department resources. Given the positions taken by ESC and PG&E, this provision is supported by the record, reasonable, and in the public interest.

t. CCUE Issues (Section 3.12(t))

In its testimony, CCUE identified various issues related to electric and gas distribution system maintenance and staffing. Section 3.12(t) provides that PG&E and CCUE have decided to address CCUE's issues through a separate agreement as part of the collective bargaining process. As a result, CCUE is withdrawing its recommendations in this proceeding without prejudice to making such recommendations in other proceedings. Given the positions taken by CCUE and PG&E, this provision is supported by the record, reasonable, and in the public interest.

VII. CONCLUSION

The principal public interest affected by this GRC is delivery of safe, reliable electric and gas service at reasonable rates. The Agreement advances this interest because it sets forth a compromise that significantly reduces the revenue requirement sought by PG&E while providing PG&E a test year revenue requirement increase and predictable attrition allowance, albeit at a level less than PG&E sought. Taken as a whole, the Agreement is reasonable in light of the entire record, consistent with the law, and in the public interest.

257/ Ex. PG&E-69, p. H-18.

For the foregoing reasons, the Settling Parties hereby request that the Commission approve the Agreement. Counsel for the Settling Parties have authorized PG&E to submit this Motion on their behalf.

Respectfully Submitted,

PATRICK G. GOLDEN
CRAIG M. BUCHSBAUM
STEVEN W. FRANK
ANN H. KIM
WILLIAM V. MANHEIM
PETER P. VAN MIEGHEM
MICHELLE L. WILSON

By: /s/
STEVEN W. FRANK

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-6976
Facsimile: (415) 973-0520
E-Mail: swf5@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 15, 2010

Attachment 1

SETTLEMENT AGREEMENT
AMONG
PACIFIC GAS AND ELECTRIC COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, AGLET CONSUMER ALLIANCE, CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION, CALIFORNIA FARM BUREAU FEDERATION, COALITION OF CALIFORNIA UTILITY EMPLOYEES, CONSUMER FEDERATION OF CALIFORNIA, DIRECT ACCESS CUSTOMER COALITION, DISABILITY RIGHTS ADVOCATES, ENERGY PRODUCERS AND USERS COALITION, ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20, MERCED IRRIGATION DISTRICT, MODESTO IRRIGATION DISTRICT, SOUTH SAN JOAQUIN IRRIGATION DISTRICT, WESTERN POWER TRADING FORUM, AND WOMEN'S ENERGY MATTERS

ARTICLE 1

In accordance with Article 12 of the California Public Utilities Commission's (Commission or CPUC) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E); the Division of Ratepayer Advocates (DRA); The Utility Reform Network (TURN); Aglet Consumer Alliance (Aglet); California City-County Street Light Association (CAL-SLA); California Farm Bureau Federation (CFBF); Coalition of California Utility Employees (CCUE); Consumer Federation of California (CFC); Direct Access Customer Coalition (DACC); Disability Rights Advocates (DisabRA);[1/] Energy Producers and Users Coalition (EPUC); Engineers and Scientists of California, Local 20

1/ DisabRA joins only in the following portions of this Agreement: Article 1, Article 2, Article 3.12(j), and Article 4.

(ESC); Merced Irrigation District (Merced ID);[2/] Modesto Irrigation District (Modesto ID);[3/] South San Joaquin Irrigation District (SSJID); Western Power Trading Forum (WPTF); and Women's Energy Matters (WEM) (collectively, the "Settling Parties") hereby enter into this Settlement Agreement (the "Agreement") as a compromise among their respective litigation positions to resolve all disputed issues raised by parties in the revenue requirement phase of PG&E's test year 2011 General Rate Case (GRC), Application 09-12-020, with the exception of one issue set forth in Section 3.9(d) related to whether PG&E should earn its authorized rate of return on its undepreciated investment in electric and gas meters replaced by SmartMeter devices.

ARTICLE 2

PROCEDURAL HISTORY

2.1 On December 21, 2009, PG&E filed its 2011 GRC Application. On February 19, 2010, the Commission convened a prehearing conference before Administrative Law Judge (ALJ) David Fukutome.

2.2 On March 5, 2010, Assigned Commissioner Michael P. Peevey issued an "Assigned Commissioner's Ruling and Scoping Memo" setting the procedural schedule, assigning ALJ Fukutome as the Presiding Officer, and addressing the scope of the proceeding and other procedural matters.

2.3 On May 5, 2010, DRA served its testimony in response to PG&E's 2011 GRC Application and supporting testimony.

2.4 On May 19, 2010, TURN, Aglet, CAL-SLA, CCUE, CFBF, DACC, EPUC, ESC, the Greenlining Institute (Greenlining), Merced ID, Modesto ID, SSJID, and WPTF served their testimony. On May 20, CFC served its testimony, and on May 26, WEM served its testimony. Also on May 26, DisabRA and PG&E submitted joint testimony concerning certain accessibility issues.

2/ Merced ID joins only in the following portions of this Agreement: Article 1, Article 2, Article 3.5.1(b), and Article 4.

3/ Modesto ID joins only in the following portions of this Agreement: Article 1, Article 2, Article 3.5.1(b), and Article 4.

2.5 On June 4, 2010, PG&E served its rebuttal testimony to DRA's and intervenors' testimony. Also on June 4, EPUC, SSJID, and WEM served reply testimony, and CCUE, Greenlining, and Southern California Edison (SCE) served rebuttal testimony.

2.6 Evidentiary hearings began on June 21, 2010 and continued through July 16, 2010, with one final witness appearing on July 22, 2010.

2.7 On July 30, 2010, PG&E served the Joint Comparison Exhibit (Exhibit PG&E-69) that provided a detailed comparison of the revenue requirement positions of PG&E and DRA, and included (as Appendix H thereto) descriptions of various intervenors' positions.

2.8 In late July 2010 and continuing during the months thereafter, parties engaged in settlement discussions. These discussions led to various extensions of the procedural schedule for this GRC.

2.9 On August 5, 2010, the Commission issued an order instituting investigation (OII) on the Commission's own motion into the rates, operations, practices, service, and facilities of PG&E. The OII is dated July 29, 2010.

2.10 On October 7, 2010, pursuant to Rule 12.1(b), PG&E notified all parties on the service list of a settlement conference to be held on October 15, 2010 to discuss the terms of the Agreement. Following the settlement conference, the Settling Parties signed this Agreement on October 15, 2010.

ARTICLE 3

SETTLEMENT OF ISSUES

3.1 2011 GRC Revenue Requirement

The Settling Parties agree that, for the issues resolved in this Agreement, PG&E's 2011 CPUC jurisdictional GRC retail revenue requirement shall be $5,977 million, a 2011 revenue requirement increase of $395 million as compared to PG&E's requested increase of $1,064 million (Ex. PG&E-69, p. 1-5, Table 1-1), to be constructed based on other terms herein.[4/] The retail revenue requirement for electric distribution is $3,190 million, for gas distribution is $1,131 million, and for electric generation is $1,656 million. The increases are $183 million for electric distribution, $47 million for gas distribution, and $166 million for electric generation.[5/] This information is shown in Appendix A.

3.2 Electric Distribution

3.2.1 Revenue Requirement Issues

The Settling Parties agree to $571 million for electric distribution expense and $1,270 million for capital expenditures for 2011.[6/] The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for electric distribution expense by at least $52 million and consists in part of the following:

(a) A reduction of $8 million in Major Work Categories (MWCs) EV and EW for New Business/Work at the Request of Others (WRO).[7/]

(b) A reduction of $18.5 million in MWC HN for vegetation management.

(c) A reduction of $2 million to reflect CAL-SLA's position on PG&E's Light Emitting Diode (LED) Streetlight Replacement Project.

3.2.2 Other Electric Distribution Issues

(a) PG&E shall retain its current one-way Vegetation Management Balancing Account (VMBA) and the separate tracking account described in the "Incremental Inspection and Removal Cost Tracking Account Accounting Procedure" in PG&E's Electric Preliminary Statement Part BU, and the annual cap for both accounts shall be set at $161 million (Fully Burdened dollars).

4/ These amounts, and all other amounts in this Agreement, are in Federal Energy Regulatory Commission (FERC) dollars unless noted otherwise. Where amounts are listed as "Fully Burdened dollars," these amounts include payroll taxes and employee benefit burdens.

5/ The $1 million difference is due to rounding.

6/ The expense amount for Electric Distribution includes Shared Services costs. The capital amount for Electric Distribution includes capital expenditures for Customer Care.

7/ MWCs EV and EW are allocated to both Electric and Gas Distribution.

(b) PG&E shall allocate work credits at the same level and in the same amount as PG&E's Rule 20A annual budgeted project amount for 2010, in order to stop the escalation of work credit allocations. Communities with projects already in progress shall be allowed to continue with their projects, even if they exceed the 5-year allowable borrowing period under the modified Rule 20A allocation method adopted herein.

(c) Electric Research Development and Demonstration (RD&D) project costs shall be reasonably allocated between generation and distribution as PG&E preliminarily outlined in Table 31-2, Exhibit PG&E-18 v3c, p. 31-11 (except for energy storage, for which PG&E has revised its forecast allocation to 50/50 generation/distribution) and, for the test year 2011 GRC cycle, the results of PG&E's prospective electric RD&D projects described in Exhibit PG&E-18 v3c, Chapter 31 shall be placed in the public domain to the extent allowed by grid security considerations.

3.3 Gas Distribution

3.3.1 Revenue Requirement Issues

The Settling Parties agree to \$196 million for gas distribution expense and \$258 million for capital expenditures for 2011.[8/] The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for gas distribution expense by at least \$30 million in the test year revenue requirement and consists in part of the following:

(a) A reduction of \$4 million in MWC EX to reflect DRA's position on the gas meter protection program.

(b) A reduction of \$4.6 million in MWC DG to reflect DRA's and TURN's positions on cathodic protection of isolated services.

(c) Maintaining currently mandated levels of gas leak inspection work.

8/ The expense amount for Gas Distribution includes Shared Services costs. The capital amount for Gas Distribution includes capital expenditures for Customer Care.

The Agreement provides sufficient funding for PG&E to perform all gas distribution operations and maintenance work at currently mandated levels.

3.3.2 Other Gas Distribution Issues

The Settling Parties agree that PG&E will create a new MWC for its Distribution Integrity Management Program (DIMP). There shall be a one-way balancing account mechanism with a cap of $60 million for DIMP costs for the term of the GRC cycle (2011-2013). Any net unspent DIMP funds at the end of this GRC cycle would be returned to customers in the next GRC. The types of work that this funding would cover include development and improvements in the following areas: DIMP program, preventive maintenance, leak surveys, operator qualifications, training, and programs such as cross-bored sewer, marker ball installation, and Aldyl-A.

3.4 Energy Supply

3.4.1 Revenue Requirement Issues

The Settling Parties agree to $541 million for energy supply expense and $330 million for capital expenditures for 2011.[9/] The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for Energy Supply Operations and Maintenance (O&M) expense and capital-related revenue requirement by at least $42 million in the test year revenue requirement and consists in part of the following:

(a) New small hydroelectric generation plants installed after test year 2011 are not approved in this proceeding but shall be reviewed in PG&E's next GRC. Review shall include cost comparison with other renewable resource alternatives.

(b) A reduction of $5 million related to the cancelled Tesla Power Plant ($1.6 million related to cancellation expense and $3.5 million related to Plant Held for Future Use (PHFU)) to resolve Settling Parties' issues regarding Tesla. PG&E reserves the right to address Tesla PHFU treatment in another proceeding.

(c) Removal of the capital costs of Britton powerhouse from PG&E's test year 2011 GRC cycle. This project will be reviewed in the next GRC.

9/ The expense amount for Energy Supply includes Shared Services costs.

(d) Removal from this GRC of the $27 million revenue requirement and request for a one-way balancing account for Renewable Resource Development (RRD). There shall be no memorandum account for RRD costs during the test year 2011 GRC cycle.

(e) A reduction of $8 million for energy procurement to resolve issues associated with utility renewable investments.

(f) Removal of PG&E's requested rate of return adder on the Kilarc-Cow decommissioning project. (Ex. PG&E-69, p. G-5-4.)

(g) A reduction in revenue requirement of $2 million to reflect reductions in hydroelectric generation capital expenditures, in addition to removal of capital costs of Britton powerhouse discussed above in subsection (c).

(h) A reduction in revenue requirement associated with the requirement that during the test year 2011 GRC cycle PG&E shall record 50% of its forecasted costs for Nuclear Energy Institute (NEI) fees below-the-line. For the 2011 test year, PG&E had forecast a total of $930,000 in NEI fees.

(i) For PG&E's new fossil generation plants, only one long-term service agreement (LTSA) payment shall be collected through normalized funding per plant. This results in a test year reduction of the O&M revenue requirement for the Gateway Generating Station.

3.4.2 Other Energy Supply Issues

(a) PG&E shall treat Diablo Canyon Power Plant labor costs associated with spent nuclear fuel removal, drying, loading, and encapsulation as operating expense, not capital expenditures.

(b) Since the Diablo Canyon Steam Generator Replacement Project was completed at a final cost below the costs (as adjusted) adopted in Decision (D.) 05-02-052, the costs shall be recovered in generation rates without the need for further reasonableness review.

(c) PG&E shall be allowed to transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account (UGBA) when the total costs of the project are known, and PG&E shall be allowed to close out the Gateway balancing account at that time.

(d) With respect to the true-up of the initial cost of the Colusa Generating Station (CGS), in accordance with D.06-11-048, which orders PG&E to retroactively true-up the CGS project's initial capital cost in the next GRC following operation to reflect 50 percent of any other savings relative to the project's initial capital cost, PG&E is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known.

(e) With respect to the true-up of the initial cost of Humboldt Bay Generating Station (HBGS), in accordance with D.06-11-048, which orders PG&E to retroactively true-up the difference between the estimated capital cost and the actual capital cost of the project in the next GRC following commercial operation, PG&E is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of D.06-11-048, when the final project costs are known.

(f) With respect to the recovery of costs in excess of the authorized initial cost of HBGS, in accordance with D.06-11-048, which authorizes PG&E to seek recovery of costs in excess of the authorized initial capital cost of $238.6 million for HBGS, if such excess costs are incurred as a result of "changes to the project as a result of new regulatory requirements or other external events," PG&E has demonstrated that an additional $25 million was incurred at HBGS due to an increase in California sales and use taxes and to address a change in configuration at the plant required by the California Energy Commission (CEC) permit to address changes in the building code and air emissions criteria. Therefore, PG&E is authorized to increase the initial capital cost target approved for the project by up to $25 million by advice letter to the extent the project's actual costs exceed the initial cost target. If the actual project costs exceed the cap by more than $25 million, as specified in D.06-11-048, PG&E shall be required to file an application with the Commission demonstrating the reasonableness of any excess amounts.

(g) PG&E stands by its prior commitment to remediate the Hunters Point Power Plant site to residential standards that are appropriate for the type of future residential development and consistent with the direction of regulators. PG&E may file a subsequent application to recover additional site-specific environmental remediation costs to the extent necessary to accommodate the development plan ultimately approved for the Hunters Point site.

(h) PG&E agrees to provide in its next GRC a status report on spent nuclear fuel payments made to the U.S. Department of Energy, associated lawsuits, and responsibility for the costs of on-site spent fuel storage at PG&E facilities. (Ex. Aglet-3, p. 2, line 24, p. 45, lines 3-16.)

3.5 Customer Care

3.5.1 Revenue Requirement Issues

The Settling Parties agree to $329 million for customer care expense for 2011.[10/] The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for Customer Care expense by at least $137 million and consists of: removal of $113 million (Fully Burdened dollars) forecast meter reading costs, $10 million of peak day pricing expense, and $14 million for other issues, as further described below.

(a) PG&E shall remove $113 million (Fully Burdened dollars) in forecast meter reading costs from requested GRC revenue requirements. PG&E shall record actual meter reading costs in a new balancing account, up to an annual cap of $76.2 million (Fully Burdened dollars), for recovery in annual revenue consolidation proceedings. In advance of the Commission's approval of this Agreement, the Settling Parties support the establishment of a memorandum account (through an advice letter to be filed by PG&E) that would allow PG&E to record such meter reading costs starting

10/ The expense amount for Customer Care includes Shared Services costs.

January 1, 2011. The purpose of this memorandum account would be to enable the recovery of these meter reading costs incurred between January 1, 2011 and the date that a new balancing account is established pursuant to the Commission's approval of this Agreement. The treatment of these meter reading costs shall be limited to the test year 2011 GRC cycle.

(b) The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast by $7 million (Fully Burdened dollars) for customer retention and economic development programs (i.e., PG&E's entire request in MWC FK). During the test year 2011 GRC cycle, PG&E shall record the customer retention costs (i.e., those historically booked to MWC FK and forecast at $4 million (Fully Burdened dollars) for 2011) incurred by its Customer Care organization below-the-line.

(c) The test year revenue requirement set forth in Section 3.1 above reduces GRC revenue requirement by $10 million for peak day pricing expenses. PG&E shall not request rate recovery of the peak day pricing activities for which expenses were requested in this GRC in another proceeding.

3.5.2 Other Customer Care Issues

(a) PG&E's uncollectibles factor shall be 0.3105% for the 2011-2013 GRC cycle. PG&E's proposals for a rolling average and for a balancing account with a deadband are not adopted.

(b) At PG&E's expense, the Commission's Energy Division shall oversee an independent audit of PG&E SmartMeter-related costs to determine whether costs that should have been recorded in the SmartMeter balancing accounts were instead recorded in other accounts, for example, accounts related to the GRC, demand response, or dynamic pricing programs. The cost to PG&E of the audit shall not exceed $200,000 and shall be recoverable through the SmartMeter balancing accounts. The purpose of the audit shall be to ensure proper booking and allocation of costs and benefits related to PG&E's SmartMeter program, including the SmartMeter upgrade, and to evaluate whether PG&E's internal cost management guidelines are adequate to ensure that all PG&E labor and non-labor costs are properly booked to its SmartMeter balancing accounts. The audit shall not include prudency or reasonableness review, or cost effectiveness of recorded costs.

(c) The SmartMeter Benefits Realization Mechanism adopted by the Commission in D.06-07-027 and D.09-03-026 shall be continued through the 2011 GRC cycle. For this period, the per-meter amounts shall be adjusted as proposed by PG&E in Table 13-3 of Exhibit PG&E-4, except that in conjunction with the removal of forecast meter reading costs from the GRC, PG&E shall also remove the meter reading savings from the electric and gas SmartMeter crediting mechanism, effective January 1, 2011.

(d) The CPUC's consultant costs for the SmartMeter evaluation described in Exhibit PG&E-13 shall be treated as any other eligible costs in the SmartMeter balancing accounts.

(e) Direct Access (DA) and Community Choice Aggregation (CCA) fees shall be conditionally adopted as proposed. PG&E commits to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA service fees. PG&E shall be allowed to cease recording costs and revenues to the Direct Access Discretionary Cost/Revenue Memorandum Account (DADCRMA), pending review of the account balance in the upcoming application.

(f) PG&E's proposal to adjust reconnection fees shall not be adopted.

(g) PG&E's proposal to adjust local office hours shall be adopted.

(h) PG&E's proposed expansion of Non-Tariffed Products and Services (NTP&S) shall be adopted, and the costs and revenues associated with the expansion of services shall be treated on a cost of service basis. PG&E's proposals concerning the 50/50 net revenue sharing mechanism and a sharing mechanism for shareholder capital shall not be adopted.

(i) PG&E's Non-sufficient Funds (NSF) Fee shall be reduced to $9 from its current level of $11.50.

3.6 Administrative and General (A&G)

3.6.1 Revenue Requirement Issues

The Settling Parties agree to $768 million for A&G expense for 2011.[11/] The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for A&G expense and capital by at least $89 million and consists in part of the following: (1) a reduction of $45 million to reflect parties' arguments regarding the Short Term Incentive Plan (STIP) (including a reduction of $2.8 million in PG&E's STIP request for PG&E Corporation); (2) a reduction of $11.4 million to reflect parties' arguments with respect to the following departments and areas: (a) Public Affairs (includes $2.5 million reduction); (b) Corporate Relations (includes $2.5 million reduction); and (c) PG&E Corporation (Corporate Services and holding company corporate items; includes $6.4 million reduction); and (3) a reduction of $1.9 million to reflect 50/50 sharing of Directors and Officers liability insurance.

The test year revenue requirement increase set forth in Section 3.1 above reflects no reduction for PG&E's test year 2011 forecast of Post-Retirement Benefits other than Pensions (PBOP)/Long-term Disability (LTD) expenses.

3.6.2 Other A&G Issues

(a) PG&E's current PBOP/LTD balancing account shall remain a one-way account. The estimate of total contributions for 2011 to the PBOPs medical and life, and LTD trusts will be $163.3 million (total company before allocation to capital and other non-GRC Unbundled Cost Categories (UCCs)). This total amount will also apply to the attrition years. In compliance with D.92-12-015 and D.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 2011 GRC cycle.

11/ The expense amount for A&G includes Shared Services costs.

(b) During the test year 2011 GRC cycle, the factors used to calculate franchise fees will be 0.007593 (electric) and 0.009789 (gas).

(c) PG&E shall modify its current Below-the-Line Guidelines to provide for: (1) Establishment and maintenance of above-the-line and below-the-line orders that would provide sufficient detail to identify discrete matters and/or activities and to enable the undertaking of an annual compliance review. This compliance review would be undertaken by PG&E and would be made available to interested parties on an annual basis. (2) Below-the-line accounting for certain PG&E activities, including all marketing and lobbying activities, in response to initiatives or proposals of local agencies for municipalization or for the formation or ongoing activities of CCAs, not just activities in response to ballot measures. (3) Annual e-mails to all employees regarding their obligation to comply with the Below-the-Line Guidelines, including the name(s) and contact information for persons to contact with questions, and a link to the guideline document. (4) Annual training on Below-the-Line Guidelines for departments that regularly direct charge to below-the-line orders. (5) Extending applicability of Below-the-Line Guidelines to PG&E Corporation employees.

(d) During the term of this 2011 test year GRC cycle, PG&E shall not accept a permanent transfer of an employee from an affiliate (including PG&E Corporation) unless PG&E is able to demonstrate that there was a need for that employee, that the employee was fully qualified for the position compared to other persons (including non-employees) that may be reasonably available to PG&E, and that the compensation to be paid the employee is within market range. Prior to any such transfer, PG&E shall memorialize its assessment of need and qualifications, including whether PG&E interviewed other candidates to fill the position. To the extent that costs associated with such transfer of employees are sought in the next GRC, PG&E shall make its assessments available to interested parties in the next GRC.

(e) Concerning meals expenses, PG&E shall keep records of business reasons for all meals, the number of attendees, and, where practical, a list of attendees by the dates shown below: (1) Beginning January 1, 2011, all meals over

$1,000, whether the meals are billed through Concur Central, to Commercial Credit cards, or to any other program or system PG&E uses to track the expenses; (2) Beginning April 1, 2011, all meals under $1,000, billed through Concur Central; and (3) Beginning July 1, 2011, all meals under $1,000, purchased through Commercial Credit cards or similar types of credit cards.

3.7 Shared Services

The Settling Parties agree to $519 million for capital expenditures for 2011. The test year revenue requirement increase set forth in Section 3.1 above reduces PG&E's forecast for Shared Services expense and capital-related revenue requirement by at least $55 million (with an additional $4.6 million reflected in A&G above) in test year revenue requirement and consists in part of the following:

(a) A reduction of at least $50 million, to resolve DRA and intervenor arguments regarding information technology (IT) costs, including TURN's arguments about Business Transformation "Foundational" programs.

(b) A reduction of $14.5 million ($4.6 million in expense, which is included in the A&G reduction above, and $9.9 million in capital for 2011) relating to the costs of sale of 111 Almaden Blvd., San Jose, and associated relocation, severance and retraining costs. No such costs shall be approved in this GRC. If PG&E sells 111 Almaden, PG&E will file a Section 851 application and may request rate recovery of the costs in the Section 851 application.

(c) A reduction of $4 million to account for the California Air Resources Board's September 9, 2010 approval of an alternative compliance plan for meeting existing California diesel fleet regulations.

3.8 Depreciation

The test year revenue requirement increase set forth in Section 3.1 above accounts for a reduction of: (1) PG&E's forecasted depreciation revenue requirement of no more than $105 million, including $22 million related to specific acceptance of DRA's position on negative net salvage, set forth in Exhibit DRA-18, p. 7, Table 18-6; and

(2) $2.5 million of generation decommissioning costs, which comprises $2 million for the Old Humboldt fossil plant and $0.5 million for Gateway, Colusa, and New Humboldt.

The 2011 depreciation parameters resulting from the Agreement are shown in Appendix B.

3.9 Capital-Related Costs, Including Rate Base and Method for Income Taxes

The test year revenue requirement increase set forth in Section 3.1 above consists in part of the following:

(a) A reduction of $35 million to reflect (1) capital expenditure reduction for New Business/WRO; (2) recalculation of 2011 rate base set forth in the December 21, 2009 application using updated estimates of bonus depreciation-related deferred tax balances from 2008 and 2009 Federal stimulus legislation; and (3) resolution of issues raised by TURN regarding income taxes, customer deposits, and materials and supplies. (In addition to the $35 million referenced above, the corresponding amount associated with PG&E's 2011 gas transmission and storage rate case is $3 million.)

(b) PG&E shall withdraw its proposal to include nuclear fuel and fuel oil inventory in rate base, reducing revenue requirement by $49 million associated with nuclear fuel, plus additional dollars associated with fuel oil. Nuclear fuel and fuel oil carrying costs will continue to be recovered through the Energy Resource Recovery Account (ERRA) at short-term commercial paper rates.

(c) PG&E's removal of all Market Redesign and Technology Upgrade (MRTU) related revenue requirements from its GRC request, totaling $20 million in 2011. For the duration of this GRC cycle, PG&E shall seek recovery of MRTU-related costs in ERRA proceedings or other proceedings if so directed by the Commission.

(d) A reduction of $44 million (revenue requirement) to reflect TURN's position to allow no rate of return on undepreciated electric and gas meters replaced by SmartMeter devices. The parties will brief the dispute for the Commission's decision in this proceeding. If PG&E prevails on the issue, the test year revenue requirement will be increased accordingly, effective January 1, 2011.

(e) The following tables reflect 2011 Rate Base and Capital Expenditure levels.

Pacific Gas and Electric Company
2011 PG&E GRC Settlement Comparison
Capital Expenditures - Functional Groups Summary
(Millions of Dollars)

	Test Year 2011	Capital Expenditures			
Line No.	Functional Groups	PG&E	Settlement	Settlement > PG&E	Line No.
1	Electric Distribution	1,370	1,270	(100)	1
2	Gas Distribution	258	258	0	2
3	Generation	370	330	(40)	3
4	Shared Services	622	519	(103)	4
5	**Total**	**2,619**	**2,376**	**(243)**	5

Pacific Gas and Electric Company
2011 PG&E GRC Settlement Comparison
Rate Base Summary
(Millions of Dollars)

	Test Year 2011				
Line No.	Functional Groups	PG&E	Settlement	Settlement > PG&E	Line No.
1	Electric Distribution	10,218	10,094	(125)	1
2	Gas Distribution	2,459	2,449	(10)	2
3	Generation	4,565	4,080	(485)	3
4	**Total**	**17,242**	**16,622**	**(620)**	4

3.10 Balancing Accounts

PG&E's proposed new balancing accounts shall not be adopted for health care costs; New Business/WRO/Rule 20A; renewable energy projects; uncollectibles; emergencies and catastrophic events; and RD&D expenses. PG&E shall continue with current electric and gas sales mechanism balancing accounts (DRAM, UGBA, CFCA, and NCA) through 2013.

3.11 Attrition Years

3.11.1 Attrition Authorized for Implementation by Advice Letter

The Settling Parties agree that attrition relief for 2012 and 2013 will be authorized in this GRC, and implemented by advice letter.

3.11.2 Attrition Amounts for 2012 and 2013

The Settling Parties agree that PG&E's annual attrition adjustment for 2012 and 2013 will be fixed dollar amounts of $180 million in 2012, and $185 million in 2013, except as provided for in Section 3.11.3 below. As shown in Appendix C to this Agreement, the 2012 increase shall be $123 million for electric distribution, $35 million for gas distribution, and $22 million for electric generation; and the 2013 increase shall be $123 million for electric distribution, $35 million for gas distribution, and $27 million for electric generation.

3.11.3 Exogenous Changes

The Settling Parties agree that PG&E's attrition mechanism will allow 2012 and 2013 revenue requirement adjustments for exogenous changes, limited to five factors (postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, *ad valorem* tax changes), with a $10 million deductible amount applicable to each factor each year.

3.12 Accounting and Other Items

(a) The forecasts of adopted gas and electric revenues at present rates as set forth in PG&E's showing (Ex. PG&E-69, p. 1-5, Table 1-1) shall be adopted.

(b) CPUC-jurisdictional Other Operating Revenues (OOR) shall be $97.9 million for electric distribution, $22.9 million for gas distribution, and $11.6 million for electric generation.

(c) The resulting revenue requirements from future cost of capital proceedings shall be calculated using the adopted 2011 rate base amounts.

(d) The revenue requirement adopted by this Agreement incorporates the following capitalization rates: 24.65% for STIP; 38.41% for Severance, Workers' Compensation, Remaining Vacation, and Pension and Benefits; and 9.3% for Third Party Claims payments.

(e) The revenue requirement adopted by this Agreement incorporates a change in the threshold after which PG&E capitalizes the development of application software from $5 million to $1 million.

(f) Capitalization factors are adopted for A&G Study departments of 7.33% for labor and 4.44% for materials.

(g) Allocation factors associated with non-utility activities are adopted for PG&E Corporation corporate items of 32.68%, below the line for workers' compensation and benefits of 0.31%, and non-utility affiliates for benefits of 0.06%.

(h) Regarding common cost (A&G and common plant) allocation factors, O&M labor factors will be calculated from 2008 recorded adjusted O&M labor. The factors are shown in Appendix D.

(i) The Settling Parties agree that A&G expenses allocated to the UCCs adopted in this 2011 GRC shall be used in determining the A&G expenses in related proceedings in 2011 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 2009 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) and subsequent NDCTP filing.

(j) The Memorandum of Understanding (MOU) between DisabRA and PG&E included in Exhibit PG&E-16 as Attachment A shall be approved by the Commission. The costs set forth in Section D of Exhibit PG&E-16 are included in the amounts set forth in Section 3.1 of this Agreement.

(k) Aglet's proposal to eliminate the requirement in D.86-12-095 that requires PG&E to prepare total factor productivity studies shall be adopted.

(l) PG&E shall be relieved of the requirement in D.04-05-055 (p. 108) to include information about long-term incentives, which are not funded by ratepayers, in future total compensation studies.

(m) Prior to submission of a Results of Operation (RO) model in PG&E's Notice of Intent (NOI) to file its next GRC application, DRA and PG&E shall review PG&E's Excel-based RO model used for the 2011 GRC, and jointly determine what changes should be made to enhance the model.

Prior to DRA's initial review of the new RO model that will be used in PG&E's 2014 GRC, PG&E shall develop a draft of the RO that: (1) shall be 100% Excel-based; (2) shall comply with the RO modeling guidelines contained in D.00-07-050; (3) shall comply with Public Utilities Code Section 1822(a); and (4) shall not require any manual movement or copying of data or files from one section of the model to another. Prior to DRA's initial review of the RO model, PG&E shall also provide DRA with the appropriate user manuals for the model.

The new PG&E RO model shall be easier to use, more functional, more transparent, and faster to run than the RO model in PG&E's 2011 GRC. The new PG&E RO model should incorporate improved logic and structure, which DRA will discuss with PG&E during the initial review, and where DRA may reference various aspects and desired features of another utility's RO model that PG&E should emulate. To ensure PG&E has adequate time to enhance the model for submission in its 2014 GRC application NOI, PG&E and DRA shall attempt to reach agreement on all changes by June 1, 2011. PG&E shall also provide DRA with a fully functional version of the model six months prior to the presentation of PG&E's NOI, with comments due back from DRA within two months. Milestones thereafter, and as necessary, shall be jointly determined by DRA and PG&E.

(n) In future GRCs, PG&E will not add a new type of cost to the revenue requirement without estimating and including in the revenue requirement the cost savings to be achieved by the new type of cost or an explanation of the reasons there will be no cost savings.

(o) PG&E shall affirmatively establish the reasonableness of all aspects of its next GRC application. For purposes of this current rate case, the Settling Parties agree that opinion testimony should have a factual foundation.

(p) PG&E shall suspend Allowance for Funds Used During Construction (AFUDC) accruals for ten Transform Operations projects identified by TURN. PG&E shall ensure that future requests for capital recovery of the projects do not include AFUDC for the period starting with the dates (November 2008 for seven projects, and February 2009 for three projects) identified in TURN's testimony and continuing until spending on the projects resumes.

(q) PG&E withdraws its testimony on the economic impacts of its capital spending during the test year 2011 GRC cycle. (Ex. PG&E-1, Appx. 2A.)

(r) Aglet withdraws the following recommendations and proposals: (1) Aglet's recommended disallowance for Reserve and Efficiency Funds (Ex. Aglet-3, p. 1, line 22, p. 14, line 1 to p. 17, line 12; Ex. PG&E-69, p. H-2, line 4); (2) Aglet's recommendation regarding sunk benefits in future Diablo Canyon cost benefit studies (Ex. Aglet-3, p. 3, line 1, p. 47, line 2 to p. 48, line 20; Ex. PG&E-69, p. H-3, line 13); (3) Aglet's recommendation to treat Diablo Canyon critical spares as plant held for future use (Ex. Aglet-3, p. 3, line 11, p. 49, line 16 to p. 50, line 5; Ex. PG&E-69, p. H-4, line 15); (4) Aglet's proposal to incorporate additional labor productivity factors into test year 2011 revenue requirements that are derived from base year 2008 recorded expenses (Ex. Aglet-3, p. 3, line 18, p. 52, line 5 to p. 53, line 15; Ex. PG&E-69, p. H-4, line 17); and (5) Aglet's recommendation for a Commission investigation into PG&E's procurement of IT products and services (Ex. Aglet-1, p. 6, line 3, p. 13, line 5 to p. 15, line 4; Ex. PG&E-69, p. H-5, line 22).

(s) PG&E and ESC have resolved certain issues associated with periodic reporting of outsourced work through the collective bargaining process. In PG&E's next GRC, PG&E shall submit testimony on the status of its workforce training programs. PG&E shall also submit testimony on the status and other results of its program for hiring in advance of employee attrition at the Diablo Canyon Power Plant and its request for additional hydroelectric department engineering and project management resources.

(t) PG&E and CCUE have decided to address CCUE's issues through a separate agreement as part of the collective bargaining process. As a result, CCUE is withdrawing its recommendations in this proceeding without prejudice to making such recommendations in other proceedings.

ARTICLE 4

GENERAL PROVISIONS AND RESERVATIONS

4.1 As a compromise among their respective litigation positions, the Settling Parties hereby agree that this Agreement resolves all disputed issues raised in this GRC, except the issue concerning rate of return on unused meters addressed in Section 3.9(d) of this Agreement. (This Agreement does not resolve the separate complaint filed by Merced ID and Modesto ID that is being considered in C.10-05-017.) The Agreement is presented to the Commission pursuant to Article 12 of the Commission's Rules of Practice and Procedure.

4.2 In accordance with Commission Rule 12.5, the Settling Parties agree that this Agreement does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

4.3 The Settling Parties agree that this Agreement represents a compromise, not agreement or endorsement of disputed facts and law presented by the Settling Parties in the 2011 GRC.

4.4 The Settling Parties shall jointly request Commission approval of this Agreement. The Settling Parties additionally agree to actively support prompt approval of the Agreement. Active support shall include briefing, comments on the proposed decision, written and oral testimony if testimony is required, appearances, and other means as needed to obtain the approvals sought. The Settling Parties further agree to participate jointly in briefings to Commissioners and their advisors as needed regarding the Agreement and the issues compromised and resolved by it.

4.5 This Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described herein, and, except as described herein, supersedes and cancels any and all prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties.

4.6 The Agreement may be amended or changed only by a written agreement signed by the Settling Parties.

4.7 Each of the Settling Parties hereto and their respective counsel and advocates have contributed to the preparation of this Agreement. Accordingly, the Settling Parties agree that no provision of this Agreement shall be construed against any Party because that Party or its counsel drafted the provision.

4.8 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.

4.9 This Agreement shall become effective among the Settling Parties on the date the last Settling Party executes the Agreement as indicated below.

4.10 Settling Parties intend the Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies the Agreement, Settling Parties reserve all rights set forth in Rule 12.4 of the Commission's Rules of Practice and Procedure.

4.11 The fact that 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 in a manner consistent with its obligation to provide reliable service and consistent with its obligation to maintain the safe operation of its utility systems. Nor does it limit the discretion of other parties to argue in future proceedings that it is unjust or unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in this proceeding or that PG&E has not provided safe and reliable service.

4.12 The fact that Settling Parties set forth specific treatment for the accounting of certain costs during the test year 2011 GRC cycle is not intended to limit the discretion of PG&E or other parties to propose different accounting treatment for such costs in the next GRC.

4.13 This Agreement constitutes the entire agreement among the Settling Parties and, except as expressly provided herein, settles all differences among them, including differences that overlap with positions taken by non-settling parties, as to the issues presented in this proceeding. Unless otherwise provided in this Agreement, all proposals and recommendations by the parties, including, but not limited to, those set forth in the Joint Comparison Exhibit (Ex. PG&E-69), are withdrawn or considered subsumed without adoption by this Agreement.

In Witness Whereof, intending to be legally bound, the Settling Parties hereto have duly executed this Agreement on behalf of the parties they represent.

/ /

/ /

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ Jane Yura

Name: JANE YURA

Date: October 15, 2010

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Joseph P. Como

Name: JOSEPH P. COMO

Date: October 15, 2010

THE UTILITY REFORM NETWORK

By: /s/ Robert Finkelstein

Name: ROBERT FINKELSTEIN

Date: October 15, 2010

AGLET CONSUMER ALLIANCE

By: /s/ James Weil

Name: JAMES WEIL

Date: October 15, 2010

CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION

By: /s/ David J. Byers

Name: DAVID J. BYERS

Date: October 15, 2010

CALIFORNIA FARM BUREAU FEDERATION

By: /s/ Ronald Liebert

Name: RONALD LIEBERT

Date: October 15, 2010

COALITION OF CALIFORNIA UTILITY EMPLOYEES

By: /s/ Rachael E. Koss

Name: RACHAEL E. KOSS

Date: October 15, 2010

CONSUMER FEDERATION OF CALIFORNIA

By: /s/ Alexis K. Wodtke

Name: ALEXIS K. WODTKE

Date: October 15, 2010

DIRECT ACCESS CUSTOMER COALITION

By: /s/ Mark Fulmer

Name: MARK FULMER

Date: October 15, 2010

DISABILITY RIGHTS ADVOCATES

By: /s/ Karla Gilbride

Name: KARLA GILBRIDE

Date: October 15, 2010

ENERGY PRODUCERS AND USERS COALITION

By: /s/ Nora Sheriff

Name: NORA SHERIFF

Date: October 15, 2010

ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20

By: /s/ Brian Cragg

Name: BRIAN CRAGG

Date: October 15, 2010

MERCED IRRIGATION DISTRICT

By: /s/ Ann L. Trowbridge

Name: ANN L. TROWBRIDGE

Date: October 15, 2010

MODESTO IRRIGATION DISTRICT

By: /s/ Ann L. Trowbridge

Name: ANN L. TROWBRIDGE

Date: October 15, 2010

SOUTH SAN JOAQUIN IRRIGATION DISTRICT

By: /s/ Salle E. Yoo

Name: SALLE E. YOO

Date: October 15, 2010

WESTERN POWER TRADING FORUM

By: /s/ D. W. Douglass

Name: D. W. DOUGLASS

Date: October 15, 2010

WOMEN'S ENERGY MATTERS

By: /s/ Martin Homec

Name: MARTIN HOMEC

Date: October 15, 2010

APPENDIX A

Results Of Operations Summary

Pacific Gas and Electric Company
2011 General Rate Case - Position Summary
Results of Operations - Test Year 2011
(Millions of Dollars)

			Joint Comparison Exhibit (PG&E-69)							
			PG&E		DRA		Settlement			
Line No.	Description	2011 Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	PG&E Reduction	Line No.
		(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (A)	(F)	(G) = (F) - (A)	(H) = (G) - (C)	
	REVENUE:									
1	Revenue Collected in Rates	5,582	6,646	1,064	5,763	181	5,977	395	(669)	1
2	Plus Other Operating Revenue	131	151	19	151	20	149	17	(2)	2
3	Total Operating Revenue	5,713	6,797	1,083	5,914	201	6,126	413	(671)	3
	OPERATING EXPENSES:									
4	Energy Costs	0	0	0	0	0	0	0	0	4
5	Production	533	574	41	471	(62)	535	2	(40)	5
6	Storage	0	4	4	3	3	4	4	0	6
7	Transmission	10	7	(3)	7	(3)	7	(3)	0	7
8	Distribution	684	852	167	625	(59)	762	78	(89)	8
9	Customer Accounts	455	483	28	390	(65)	320	(135)	(163)	9
10	Uncollectibles	15	19	4	16	0	19	4	(0)	10
11	Customer Services	17	15	(2)	9	(8)	9	(8)	(6)	11
12	Administrative and General	673	857	184	642	(32)	768	95	(89)	12
13	Franchise Requirements	46	54	8	47	1	49	2	(5)	13
14	Amortization	7	6	(1)	5	(3)	6	(1)	0	14
15	Wage Change Impacts	0	0	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	0	0	16
17	Other Adjustments	(2)	0	2	0	2	(49)	(47)	(49)	17
18	Subtotal Expenses:	2,440	2,872	432	2,214	(226)	2,430	(10)	(442)	18
	TAXES:									
19	Superfund	0	0	0	0	0	0	0	0	19
20	Property	169	208	39	204	36	208	39	(0)	20
21	Payroll	89	105	16	82	(7)	92	3	(13)	21
22	Business	1	1	0	1	0	1	0	(0)	22
23	Other	0	2	2	4	4	2	2	0	23
24	State Corporation Franchise	122	119	(3)	111	(11)	105	(17)	(14)	24
25	Federal Income	513	489	(23)	458	(55)	463	(49)	(26)	25
26	Total Taxes	893	924	32	860	(33)	871	(21)	(53)	26
27	Depreciation	1,082	1,444	362	1,376	293	1,325	243	(119)	27
28	Fossil Decommissioning	(24)	41	65	35	59	38	63	(3)	28
29	Nuclear Decommissioning	0	0	0	0	0	0	0	0	29
30	Total Operating Expenses	4,391	5,281	890	4,484	93	4,665	274	(616)	30
31	Net for Return	1,322	1,516	193	1,430	107	1,461	139	(54)	31
32	Rate Base	15,041	17,242	2,200	16,264	1,223	16,622	1,581	(620)	32
	RATE OF RETURN:									
33	On Rate Base	**8.79%**	**8.79%**		**8.79%**		**8.79%**			33
34	On Equity	**11.35%**	**11.35%**		**11.35%**		**11.35%**			34

Col (A) These amounts include revenues from PG&E's 2007 GRC Decision 07-03-044, adjusted for 2008 attrition, 2008 cost of capital, and 2009 & 2010 attrition. These amounts also include the 2011 revenue requirements associated with the Diablo Canyon Power Plant (DCPP) Steam Generator Replacement Project, as well as the Gateway, Humboldt, and Colusa Generating Stations. These amounts exclude pension costs, which were resolved by the Commission in D.09-09-020.

APPENDIX A

Summary of Increase by Electric, Gas Distribution, and Generation

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF INCREASE OVER 2011 ESTIMATED AUTHORIZED
(Millions of Doliars)

			Joint Comparison Exhibit (PG&E-69)				Settlement			
			PG&E		DRA					
				Difference		Difference		Difference		
		2011	2011	from	2011	from	2011	from	PG&E	
Line		Authorized	Proposed	Authorized	Proposed	Authorized	Proposed	Authorized	Reduction	Line
		(A)	(B)	(C) = (B) - (A)	(D)	(E) = (D) - (A)	(F)	(G) = (F) - (A)	(H) = (G) - (C)	
	Electric Distribution									
1	Operation and Maintenance	535	627	92	486	(49)	571	36	(56)	1
2	Customer Services	270	290	20	231	(40)	192	(79)	(98)	2
3	Administrative & General	318	431	113	323	5	386	68	(45)	3
4	Less: Revenue Credits (OORs & Wheeling)	(95)	(116)	(21)	(116)	(21)	(114)	(19)	2	4
5	FF&U, Other Adjs, Taxes Other than Income	73	88	15	73	1	34	(38)	(53)	5
6	Return, Taxes & Depreciation	1,906	2,214	308	2,153	247	2,120	214	(94)	6
7	Retail Revenue Requirement	3,007	3,534	527	3,151	144	3,190	183	(344)	7
	Gas Distribution									
8	Operation and Maintenance	153	229	76	142	(11)	196	42	(34)	8
9	Customer Services	202	208	6	169	(33)	138	(64)	(71)	9
10	Administrative & General	178	212	34	159	(19)	190	12	(22)	10
11	Less: Revenue Credits (OORs)	(26)	(23)	3	(23)	3	(23)	3	-	11
12	FF&U, Other Adjs, Taxes Other than Income	37	45	7	35	(2)	38	1	(7)	12
13	Return, Taxes & Depreciation	540	622	82	590	50	593	53	(29)	13
14	Retail Revenue Requirement	1,084	1,293	208	1,072	(12)	1,131	47	(161)	14
	Electric Generation									
15	Operation and Maintenance	539	581	42	477	(62)	541	2	(40)	15
16	Customer Services	-	-	-	-	-	-	-	-	16
17	Administrative & General	177	214	37	160	(18)	192	15	(22)	17
18	Less: Revenue Credits (OORs & Resale)	(10)	(12)	(2)	(12)	(2)	(12)	(2)	0	18
19	FF&U, Other Adjs, Taxes Other than Income	47	56	9	46	(1)	47	0	(8)	19
20	Return, Taxes & Depreciation	737	981	244	869	132	887	151	(93)	20
21	Retail Revenue Requirement	1,490	1,820	329	1,540	49	1,656	166	(164)	21
	Total									
22	Operation and Maintenance	1,228	1,437	209	1,105	(122)	1,308	80	(129)	22
23	Customer Services	472	498	26	400	(73)	329	(143)	(169)	23
24	Administrative & General	673	857	184	642	(31)	768	95	(89)	24
25	Less: Revenue Credits (OORs & Resale)	(131)	(151)	(19)	(151)	(20)	(149)	(17)	2	25
26	FF&U, Other Adjs, Taxes Other than Income	157	188	31	154	(3)	120	(37)	(68)	26
27	Return, Taxes & Depreciation	3,183	3,816	634	3,613	430	3,601	418	(216)	27
28	Subtotal Retail Revenue Requirement	5,582	6,646	1,064	5,763	181	5,977	395	(669)	28

Col (A) These amounts include revenues from PG&E's 2007 GRC Decision 07-03-044, adjusted for 2008 attrition, 2008 cost of capital, and 2009 & 2010 attrition. These amounts also include the 2011 revenue requirements associated with the Diablo Canyon Power Plant (DCPP) Steam Generator Replacement Project, as well as the Gateway, Humboldt, and Colusa Generating Stations. These amounts exclude pension costs, which were resolved by the Commission in D.09-09-020.

Note: Columns and rows may not add due to rounding.

Appendix A
Electric and Gas Distribution Expense
TY2011
Settlement Amounts by Major Work Category
(In Thousands of Dollars)

Major Work Category (a)	Description (b)	PG&E Proposed (c)	DRA Recommended (d)	Settlement Amount (e)	PG&E > Settlement (f = e-c)
BF	Patrols and Inspections	$ 40,712	$ 33,225	$ 40,712	$ -
BG	Preventive Maintenance & Equipment Repair	84,810	61,474	72,665	(12,145)
BK	Maintenance of Other Equipment	2,057	1,785	2,057	-
GA	Poles Test/Treat, Restoration, Joint Utilities Coord	16,462	13,173	16,462	-
HN [1]	Vegetation Management	180,000	160,667	161,500	(18,500)
EV	New Business	17,488	16,519	13,488	(4,000)
EW	Work at the Request of Others	25,296	21,983	21,296	(4,000)
GC	Operate and Maintain Substations	37,938	30,908	34,423	(3,515)
HX	Distribution Automation & Protection Support	1,900	1,233	1,900	-
GB	Underground Asset Mgmt. Splice/Connector Replacement Exp	800	378	800	-
BA	Operate Electric Distribution	39,081	32,965	36,023	(3,058)
HG	Electric Distribution Operations Tech	750	750	750	-
BH	Corrective Maintenance-Expense	68,441	60,794	64,618	(3,823)
IF	Major Emergency- Expense	24,199	18,282	21,240	(2,959)
FZ	Electric Engineering & Planning	25,062	20,761	25,062	-
GE	Operations Distrb-Electric Mapping	7,114	5,341	7,114	-
GF	Operations Distrb-Gas Mapping	1,600	1,445	1,600	-
AB	Electric Research Development & Demo	2,800	1,400	2,800	-
AB	Operations Support Expense	5,935	4,224	5,935	-
	Electric Distribution Total	**582,445**	**487,307**	**530,445**	**(52,000)**
DE	Leak Survey	15,482	10,480	15,482	-
DF	Mark & Locate	29,902	28,222	29,902	-
DG	Cathodic Protection	15,357	8,802	10,757	(4,600)
FH	Preventive Maint.	16,924	11,990	16,924	-
FI	Correct. Maint.	48,496	18,325	35,656	(12,840)
FG	Opr. Gas Sys	3,945	3,945	3,945	-
GG	Gas Engineering	3,060	3,060	3,060	-
GZ	Gas Dist. Res.	1,500	750	1,500	-
New MWC [2]	Distribution Integrity Management Program (DIMP)	23,546	10,410	19,500	(4,046)
EX	Meter Protection	5,200	527	1,200	(4,000)
AB	Technical Training	19,083	500	14,569	(4,514)
AB	Applied Tech	1,751	835	1,751	-
	Gas Distribution Total	**184,246**	**97,846**	**154,246**	**(30,000)**
	Electric & Gas Distribution Total	**$ 766,691**	**$ 585,153**	**$ 684,691**	**$ (82,000)**

[1] Continuation of 1-way balancing account

[2] Creation of a 1-way balancing account

Appendix B

Pacific Gas and Electric Company
2011 General Rate Case

Settlement Net Salvage and Accrual Rates

Ln	Asset Class	Note	FERC Acct.	Description	Net Salvage Rates PG&E Proposed (%)	Net Salvage Rates DRA Proposed (%)	Net Salvage Rates Settlement (%)	Accrual Rates PG&E Proposed (%)	Accrual Rates DRA Proposed (%)	Accrual Rates Settlement (%)
				ELECTRIC						
				Intangible Plant						
1	EIP30201		302	Franchises and Consents	0		0	2.23		2.23
2	EIP30301		303	USBR - Limited Term Electric	0		0	0.00		0.00
3	EIP30303		303	Software	0		0	0.00		0.00
				Steam Production Plant - Combined Cycle						
4	ESF31103		311	Structures & Improvements	0		0	3.52		3.52
5	ESF31203/ESF31205		312	Boiler Plant Equipment	0		0	3.52		3.52
6	ESF31403		314	Turbogenerator Units	0		0	3.52		3.52
7	ESF31503		315	Accessory Electrical Equipment	0		0	3.52		3.52
8	ESF31603		316	Miscellaneous Power Plant Equipment	0		0	3.52		3.52
				Steam Production Plant - Other Steam Production						
9	ESF31101		311	Structures & Improvements	0		0	8.36		8.36
10	ESF31201		312	Boiler Plant Equipment	0		0	8.36		8.36
11	ESF31301		313	Engines and Engine-Driven Generators	0		0	8.36		8.36
12	ESF31401		314	Turbogenerator Units	0		0	8.36		8.36
13	ESF31501		315	Accessory Electrical Equipment	0		0	8.36		8.36
14	ESF31601		316	Miscellaneous Power Plant Equipment	0		0	8.36		8.36
				Nuclear Production - 2001 & Prior						
15	ENP32100		321	Structures & Improvements	-3		-3	0.17		0.17
16	ENP32200		322	Reactor Plant Equipment	-5		-5	0.40		0.40
17	ENP32300		323	Turbogenerator Units	-2		-2	0.13		0.13
18	ENP32400	1	324	Accessory Electrical Equipment	-5		-2	0.34		0.12
19	ENP32500	1	325	Miscellaneous Power Plant Equipment	-4		-2	0.27		0.13
				Nuclear Production - 2002 & Subsequent						
20	ENP32102		321	Structures & Improvements	-3		-3	6.58		6.58
21	ENP32201		322	Reactor Plant Equipment U2	-5		-5	6.59		6.59
22	ENP32202		322	Reactor Plant Equipment	-5		-5	6.59		6.59
23	ENP32302		323	Turbogenerator Units	-2		-2	6.46		6.46
24	ENP32402	1	324	Accessory Electrical Equipment	-5		-2	6.57		6.38
25	ENP32502	1	325	Miscellaneous Power Plant Equipment	-4		-2	6.48		6.35
				Hydroelectric Production excluding Helms Pumped Storage						
26	EHP33101/EHP33102/EHP33103		331	Structures & Improvements	0		0	1.90		1.90
27	EHP33201/EHP33202/EHP33203		332	Reservoirs, Dams & Waterways	0		0	1.43		1.43
28	EHP33300	1	333	Waterwheels, Turbines & Generators	-2		0	2.49		2.39
29	EHP33400	1	334	Accessory Electrical Equipment	-14		0	4.12		3.29
30	EHP33500	1	335	Miscellaneous Power Plant Equipment	-8		0	3.83		3.42
31	EHP33600		336	Roads, Railroads & Bridges	0		0	3.06		3.06
				Hydroelectric Production - Helms Pumped Storage						
32	EHH33101		331	Structures & Improvements	-1		-1	0.00		0.00
33	EHH33201		332	Reservoirs, Dams & Waterways	-1		-1	0.00		0.00

Ln	Asset Class	Note	FERC Acct.	Description	Net Salvage Rates PG&E Proposed (%)	Net Salvage Rates DRA Proposed (%)	Net Salvage Rates Settlement (%)	Accrual Rates PG&E Proposed (%)	Accrual Rates DRA Proposed (%)	Accrual Rates Settlement (%)
34	EHH33300		333	Waterwheels, Turbines & Generators	-4		-4	0.35		0.35
35	EHH33400		334	Accessory Electrical Equipment	-15		-15	0.89		0.89
36	EHH33500		335	Miscellaneous Power Plant Equipment	-10		-10	0.64		0.64
37	EHH33600		336	Roads, Railroads & Bridges	0		0	0.00		0.00
				Other Production - Combined Cycle Production						
38	EOP34101		341	Structures & Improvements	0		0	3.52		3.52
39	EOP34201		342	Fuel Holders, Producers and Accessories	0		0	3.52		3.52
40	EOP34301		343	Prime Movers	0		0	3.52		3.52
41	EOP34401		344	Generators	0		0	3.52		3.52
42	EOP34501		345	Accessory Electrical Equipment	0		0	3.52		3.52
43	EOP34601		346	Miscellaneous Power Plant Equipment	0		0	3.52		3.52
				Other Production - Solar						
44	EOP34602		346	Miscellaneous Power Plant Eqp - Solar	0		0	3.97		3.97
				All Other Production						
45	EOP34100		341	Structures & Improvements	0		0	3.33		3.33
46	EOP34200		342	Fuel Holders, Producers and Accessories	0		0	33.40		33.40
47	EOP34300		343	Prime Movers	0		0	0.00		0.00
48	EOP34400		344	Generators	0		0	2.85		2.85
49	EOP34500		345	Accessory Electrical Equipment	0		0	4.31		4.31
50	EOP34600		346	Miscellaneous Power Plant Equipment	0		0	13.35		13.35
				Electric Transmission (Generation (ETC))						
51	ETC35201		352	Structures & Improvements	-20		-20	1.54		1.54
52	ETC35301	1, 2	353	Station Equipment	-50	-30	-30	3.10	2.51	2.51
53	ETC35302		353	Step Up Transformers	-5		-5	2.67		2.67
54	ETP35303		353	Step Up Transformers (Combined Cycle)	-5		-5	4.74		4.74
55	ETC35400	1, 2	354	Towers & Fixtures	-80	-60	-60	2.41	1.96	1.96
56	ETP35401		354	Towers & Fixtures (Combined Cycle)	-80		-80	5.99		5.99
57	ETC35500		355	Poles & Fixtures	-80		-80	3.19		3.19
58	ETC35600		356	OH Conductor/Devices - Twr/Pl Ln	-80		-80	3.21		3.21
59	ETP35601		356	OH Conductors & Devices (Combined Cycle)	-80		-80	5.99		5.99
60	ETC35700		357	UG Conduit	0		0	0.60		0.60
61	ETC35800		358	UG Conductor/Devices	0		0	0.75		0.75
62	ETC35900		359	Roads & Trails	0		0	1.38		1.38
				Nuclear Transmission Plant						
63	NTP35201		352	Structures & Improvements	-20		-20	1.27		1.27
64	NTP35202		352	Structures & Improvements-Equipment	-20		-20	1.26		1.26
65	NTP35301		353	Station Equipment	-50		-50	3.26		3.26
66	NTP35302		353	Step-up Transformers	-5		-5	1.60		1.60
				Electric Distribution						
67	EDP36101		361	Structures & Improvements	-20		-20	2.21		2.21
68	EDP36102		361	Structures & Improvements-Eqpt	-20		-20	2.37		2.37
69	EDP36200	1, 2	362	Station Equipment	-40	-25	-15	3.79	3.27	2.92
70	EDP36300		363	Storage Battery Equipment	0		0	35.04		35.04
71	EDP36400	1	364	Poles, Towers, & Fixtures	-90		-80	5.05		4.70
72	EDP36500	1	365	OH Conductors & Devices	-85		-77	4.93		4.64
73	EDP36600	1	366	Underground Conduit	-25		-20	2.54		2.42
74	EDP36700		367	UG Conductors & Devices	-40		-40	3.42		3.42
75	EDP36801	1	368	Line Transformers-Overhead	-10		-6	3.63		3.44
76	EDP36802		368	Line Transformers-Underground	5		5	3.36		3.36
77	EDP36901	1	369	Services-Overhead	-100		-75	4.05		3.25
78	EDP36902	1	369	Services-Underground	-40		-29	3.15		2.78
79	EDP37000	1, 2	370	Meters	-30	-15	-15	4.71	3.96	3.96
80	EDP37100		371	Installation on Customer Premises	0		0	0.00		0.00
81	EDP37200		372	Leased Property on Cust. Prem.	0		0	0.00		0.00
82	EDP37301		373	Street Light-Overhead Conductors	-35		-35	2.23		2.23
83	EDP37302		373	Street Light-Conduit & Cables	-10		-10	5.01		5.01
84	EDP37303	1	373	Street Light-Lamps & Equipment	-15		-5	2.61		1.90
85	EDP37304		373	Street Light-Electroliers	-10		-10	2.61		2.61

					Net Salvage Rates			Accrual Rates		
Ln	Asset Class	Note	FERC Acct.	Description	PG&E Proposed (%)	DRA Proposed (%)	Settlement (%)	PG&E Proposed (%)	DRA Proposed (%)	Settlement (%)
				ElectricGeneral						
86	EGP39000		390	Structures & Improvements	-10		-10	2.13		2.13
87	EGP39100		391	Office Furniture & Equipment	0		0	9.72		9.72
88	EGP39400		394	Tools, Shop & Garage Equipment	0		0	3.44		3.44
89	EGP39500		395	Laboratory Equipment	0		0	8.09		8.09
90	EGP39600		396	Power Operated Equipment	0		0	5.86		5.86
91	EGP39700		397	Communication Equipment	0		0	4.32		4.32
92	EGP39800		398	Miscellaneous Equipment	0		0	13.84		13.84
				Nuclear General Plant						
93	NGP39100		391	Office Furniture & Equipment	0		0	0.00		0.00
94	NGP39800		398	Miscellaneous Equipment	0		0	0.00		0.00
				GAS						
				Intangible Plant						
95	GIP30202		302	Franchises and Consents	0		0	9.60		9.60
96	GIP30302		303	Software	0		0	0.00		0.00
				Local Storage Plant						
97	GLS36101		361	Structures & Improvements	10		10	1.80		1.80
98	GLS36200		362	Gas Holders	-15		-15	4.17		4.17
99	GLS36300		363	Purification Equipment	0		0	4.14		4.14
100	GLS36330		363.3	Compressor Equipment	-20		-20	4.84		4.84
101	GLS36340		363.4	Measuring & Regulating Equipment	10		10	2.85		2.85
102	GLS36350		363.5	Other Equipment	-5		-5	2.87		2.87
				Gas Distribution						
103	GDP37500		375	Structures & Improvements	-20		-20	2.46		2.46
104	GDP37601	1	376	Mains	-60		-52	2.94		2.72
105	GDP37700		377	Compressor Station Equipment	0		0	2.81		2.81
106	GDP37800	1, 2	378	Odorizing/Meas & Reg Sta Equipment	-55	-45	-45	3.09	2.78	2.78
107	GDP38000	1	380	Services	-120		-105	3.76		3.36
108	GDP38100	1, 2	381	Meters	-50	-25	-5	8.22	6.49	5.10
109	GDP38300		383	House Regulators	0		0	3.22		3.22
110	GDP38500		385	Meas & Reg Sta Equip-Industrial	0		0	1.75		1.75
111	GDP38600		386	Other Property on Customer Premises	0		0	2.58		2.58
112	GDP38700		387	Other Equipment	5		5	2.30		2.30
				Gas General						
113	GGP39000		390	Structures & Improvements	-10		-10	2.55		2.55
114	GGP39100		391	Office Furniture & Equipment	0		0	8.20		8.20
115	GGP39400		394	Shop Equipment	0		0	4.12		4.12
116	GGP39500		395	Laboratory Equipment	0		0	9.87		9.87
117	GGP39600		396	Power Operated Equipment	0		0	18.90		18.90
118	GGP39800		398	Miscellaneous Equipment	0		0	6.30		6.30
119	GGP39900		399	Other Tangible Property	0		0	12.37		12.37

Ln	Asset Class	Note	FERC Acct.	Description	Net Salvage Rates PG&E Proposed (%)	Net Salvage Rates DRA Proposed (%)	Net Salvage Rates Settlement (%)	Accrual Rates PG&E Proposed (%)	Accrual Rates DRA Proposed (%)	Accrual Rates Settlement (%)
				COMMON						
				Common Plant						
120	CMP30302		303	Computer Software	0		0	19.81		19.81
121	CMP30304		303	Computer Software - CIS	0		0	6.59		6.59
122	CMP39000	1	390	Structures & Improvements	-10		-10	2.59		2.23
123	CMP39101		391	Office Machines & Computer Eqpt	0		0	19.51		19.51
124	CMP39102	1	391	PC Hardware	0		0	33.84		20.00
125	CMP39103	1	391	Office Furniture & Equipment	0		0	6.28		3.33
126	CMP39104		391	Off Mach & Computer Eqpt - CIS	0		0	6.39		6.39
127	CMP39201		392	Transportation Equipment - Air	50		50	2.64		2.64
128	CMP39202		392	Transportatioin Equipment - Class P	10		10	8.30		8.30
129	CMP39203		392	Transportation Equipment - Class C2	10		10	6.71		6.71
130	CMP39204		392	Transportation Equipment - Class C4	10		10	15.57		15.57
131	CMP39205		392	Transportation Equipment - Class T1 - Body	10		10	9.85		9.85
132	CMP39255		392	Transportation Equipment - Class T1 - Chassis	10		10	9.73		9.73
133	CMP39206		392	Transportation Equipment - Class T3 - Body	10		10	7.90		7.90
134	CMP39256		392	Transportation Equipment - Class T3 - Chassis	10		10	7.93		7.93
135	CMP39207		392	Transportation Equipment - Class T4 - Body	10		10	5.94		5.94
136	CMP39257		392	Transportation Equipment - Class T4 - Chassis	10		10	6.08		6.08
137	CMP39208		392	Transportation Equipment - Vessels	10		10	0.00		0.00
138	CMP39209		392	Transportation Equipment - Trailers	10		10	0.88		0.88
139	CMP39300		393	Stores Equipment	0		0	6.29		6.29
140	CMP39400		394	Tools, Shop & Garage Equipment	0		0	2.81		2.81
141	CMP39500		395	Laboratory Equipment	0		0	6.34		6.34
142	CMP39600		396	Power Operated Equipment	20		20	7.66		7.66
143	CMP39701		397	Communication Equipment - Non-Computer	0		0	15.93		15.93
144	CMP39702		397	Communication Equipment - Computer	0		0	19.08		19.08
145	CMP39703		397	Communication Equipment - Radio Systems	0		0	14.28		14.28
146	CMP39704	1	397	Communication Equipment - Voice Systems	-15		-4	18.18		14.42
147	CMP39705		397	Communication Equipment - Transm Systems	0		0	6.74		6.74
148	CMP39800		398	Miscellaneous Equipment	0		0	6.17		6.17
149	CMP39900		399	Other Tangible Property	0		0	5.97		5.97
				Common Plant - Nuclear						
150	CNP30302		303	DCPP Software	0		0	10.59		10.59
151	CNP39000		390	Structures & Improvements	-10		-10	1.54		1.54
152	CNP39101		391	Office Machines & Computer Equipment	0		0	35.02		35.02
153	CNP39102		391	PC Hardware	0		0	35.54		35.54
154	CNP39103		391	Office Furniture & Equipment	0		0	0.95		0.95
155	CNP39202		392	Transportation Equipment - Class P	10		10	0.00		0.00
156	CNP39203		392	Transportation Equipment - Class C2	10		10	7.04		7.04
157	CNP39204		392	Transportation Equipment - Class C4	10		10	7.18		7.18
158	CNP39205		392	Transportation Equipment - Class T1	10		10	6.15		6.15
159	CNP39206		392	Transportation Equipment - Class T3	10		10	6.83		6.83
160	CNP39207		392	Transportation Equipment - Class T4	10		10	4.59		4.59
161	CNP39208		392	Transportation Equipment - Vessels	10		10	0.00		0.00
162	CNP39209		392	Transportation Equipment - Trailers	10		10	0.28		0.28
163	CNP39300		393	Stores Equipment	0		0	5.71		5.71
164	CNP39400		394	Tools, Shop & Garage Equipment	0		0	0.00		0.00
165	CNP39500		395	Laboratory Equipment	0		0	2.33		2.33
166	CNP39600		396	Power Operated Equipment	20		20	5.07		5.07
167	CNP39701		397	Communications Equipment - Non-Computer	0		0	16.12		16.12
168	CNP39702		397	Communications Equipment - Computer	0		0	22.67		22.67
169	CNP39703		397	Communications Equipment - Radio Systems	0		0	15.00		15.00
170	CNP39704		397	Communications Equipment - Voice Systems	0		0	14.46		14.46
171	CNP39705		397	Communications Equipment - Trans Systems	0		0	1.53		1.53
172	CNP39800		398	Miscellaneous Equipment	0		0	4.20		4.20

Notes:

173 1 Account with settlement net salvage and accrual rates that are different from those proposed by PG&E in the 2011 GRC Application

174 2 Account specifically identified by DRA for net salvage reduction

Appendix C
Pacific Gas and Electric Company
2011 GRC Settlement Agreement
Attrition

(Millions of Dollars)

		2012 Increase	2013 Increase
1	Electric Distribution	123	123
2	Gas Distribution	35	35
3	Electric Generation	22	27
4	Total	180	185

Appendix D
Pacific Gas and Electric Company
2011 GRC Settlement Agreement
O&M Labor Factors

Line	Unbundled Cost Category (UCC)	Comparison Exhibit 8 Recorded Adjusted Lab $	%		Reclass EP Labor [3]	Settlement Agreement 2008 Recorded Adjusted Labor[1] $	%
	Electric Department						
1	100 EG - Power Generation	-	0.00%		-	-	0.00%
2	101 EG - Fossil Facilities	-	0.00%		-	-	0.00%
3	102 EG - Fossil Transmission	126	0.01%		-	126	0.01%
4	103 EG - Gateway	2,755	0.26%		-	2,755	0.26%
5	104 EG - Colusa	2,052	0.20%		-	2,052	0.20%
6	105 EG - Humboldt Bay GS Repower	1,411	0.14%		-	1,411	0.14%
7	106 EG - Other Generation Solar	-	0.00%		-	-	0.00%
8	107 EG - Tesla	-	0.00%		-	-	0.00%
9	120 EG - Hydro Facilities	48,927	4.69%		-	48,927	4.69%
10	121 EG - Hydro Transmission	822	0.08%		-	822	0.08%
11	122 EG - New Renewable Hydro	-	0.00%		-	-	0.00%
12	123 EG - Helms Generation Facilities	3,815	0.37%		-	3,815	0.37%
13	124 EG - Helms Transmission	1,192	0.11%		-	1,192	0.11%
14	130 EG - Diablo Canyon Nuclear Generation Facilities	148,241	14.21%		-	148,241	14.21%
15	131 EG - Diablo Canyon Transmission	-	0.00%		-	-	0.00%
16	132 EG - Diablo Canyon Steam Generator Replacement	-	0.00%		-	-	0.00%
17	133 EG - Diablo Canyon Decommissioning (incl. SAFSTOR)	-	0.00%		-	-	0.00%
18	135 EG - Humboldt Unit 3 Decommissioning	-	0.00%		-	-	0.00%
19	140 EG - Power Purchase Payments	-	0.00%		-	-	0.00%
20	141 EG - Electric Procurement (incl. QF & Other Power Payment Admin)	19,220	1.84%		1,377	20,597	1.97%
21	142 EG - Market Redesign Technology Update - MRTU	1,377	0.13%		(1,377)	-	0.00%
22	**Power Generation (GRC) Total**	229,937	22.03%	GRC [2]	-	229,937	22.03%
23	134 EG - Humboldt Unit 3 SAFSTOR Costs	4,987	0.48%		-	4,987	0.48%
24	**Power Generation (Other) Total**	4,987	0.48%		-	4,987	0.48%
23	200 ET - Network Transmission	-	0.00%		-	-	0.00%
24	201 ET - High Voltage Network Facilities	32,690	3.13%		-	32,690	3.13%
25	202 ET - Low Voltage Network Facilities	33,890	3.25%		-	33,890	3.25%
26	203 ET - Partnership Agreement Generation-Ties	38	0.00%		-	38	0.00%
27	204 ET - Third-Party Generation-Ties	465	0.04%		-	465	0.04%
28	205 ET - Canadian Line	-	0.00%		-	-	0.00%
29	**Transmission Total**	67,083	6.43%		-	67,083	6.43%
30	301 ED - Wires and Services	398,692	38.21%		-	398,692	38.21%
31	302 ED - Transmission-Level Direct Connects	326	0.03%		-	326	0.03%
32	303 ED - Public Purpose Program Administration	64,014	6.13%		-	64,014	6.13%
33	304 ED - Demand Response	-	0.00%		-	-	0.00%
34	305 ED - Dynamic Pricing	-	0.00%		-	-	0.00%
35	306 ED - Cornerstone	-	0.00%		-	-	0.00%
36	**Electric Distribution Total**	463,032	44.37%	GRC [2]	-	463,032	44.37%
37	307 ED - SmartMeter Electric	3,846	0.37%		-	3,846	0.37%
38	400 EP - Electric PPP Programs	-	0.00%		-	-	0.00%
39	**Other Total**	3,846	0.37%		-	3,846	0.37%
40	**Electric Department Total**	768,886	73.68%		-	768,886	73.68%
	Gas Department						
41	500 GT - Gas Transmission and Storage	-	0.00%		-	-	0.00%
42	501 GT - Gathering	2,321	0.22%		-	2,321	0.22%
43	510 GS - Storage Services - All	-	0.00%		-	-	0.00%
44	511 GS - Storage Services - McDonald Island	4,166	0.40%		-	4,166	0.40%
45	512 GS - Storage Services - Los Medanos/Pleasant Creek	2,467	0.24%		-	2,467	0.24%
46	513 GS - Storage Services - Gill Ranch	8	0.00%		-	8	0.00%
47	520 GT - Local Transmission	18,609	1.78%		-	18,609	1.78%
48	521 GT - Transmission: Northern Path – Line 401	577	0.06%		-	577	0.06%
49	522 GT - Transmission: Northern Path – Line 400	3,090	0.30%		-	3,090	0.30%
50	523 GT - Transmission: Northern Path – Line 2	-	0.00%		-	-	0.00%
51	524 GT - Transmission: Southern Path – Line 300 North Milpitas to Panoche	1,011	0.10%		-	1,011	0.10%
52	525 GT - Transmission: Southern Path – Line 300 South Topock to Panoche	10,919	1.05%		-	10,919	1.05%
53	526 GT - Transmission: Bay Area Loop	1,768	0.17%		-	1,768	0.17%
54	527 GT - Excess Line 401	-	0.00%		-	-	0.00%
55	528 GT - Customer Access Charge (CAC)	858	0.08%		-	858	0.08%
56	**Gas Transmission Total**	45,794	4.39%		-	45,794	4.39%
57	600 GD - Gas Distribution	-	0.00%		-	-	0.00%
58	601 GD - Pipes and Services	217,606	20.85%		-	217,606	20.85%
59	602 GD - Gas Procurement	2,329	0.22%		-	2,329	0.22%
60	603 GD - Public Purpose Program Administration	7,402	0.71%		-	7,402	0.71%
61	**Gas Distribution Total**	227,338	21.79%	GRC [2]	-	227,338	21.79%
62	604 GD - SmartMeter Gas	1,515	0.15%		-	1,515	0.15%
63	**Gas Department Total**	274,647	26.32%		-	274,647	26.32%
							0.00%
64	**PG&E Total Labor**	1,043,533	100.00%		-	1,043,533	100.00%
65	**PG&E 2011 General Rate Case Factor**		88.19%	GRC [2]			88.19%

[1]Adjusted for plants no longer in service and new plants that will be in service in 2011, Smart Meter and Public Purpose Programs
[2] GRC Total = 88.19%
[3] Reclass Energy Procurement Labor to align with 2011 Forecast.

Attachment 2

Table 1-1

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
General Rate Case Revenues: Electric Distribution
Available from Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUES AT PRESENT RATES						
	CPUC Revenues (Retail)						
1	Retail Revenue Collected in Rates	3,007,541	3,007,541	0	3,007,000	541	1
2	Plus: Other Operating Revenue (Adopted in GRC)	80,099	80,099	0	80,099	0	2
3	Total CPUC Jurisdiction Revenue	3,087,640	3,087,640	0	3,087,099	541	3
	FERC Jurisdiction Wholesale Revenue						
4	Wholesale Wheeling & Resale Revenue	15,799	15,799	0	15,799	0	4
5	Plus: Wholesale Other Operating Revenue	0	0	0	0	0	5
6	Total Wholesale Revenue	15,799	15,799	0	15,799	0	6
7	Total Operating Revenue (Present)	3,103,439	3,103,439	0	3,102,898	541	7
	REVENUES AT PROPOSED RATES						
8	Revenue Requirement	3,649,588	3,303,846	(345,742)	3,267,058	36,788	8
	(Test Year 2011, line 3, tab RO_Proposed)						
9	Less: Total Wholesale Revenue-FERC (Line 6)	15,799	15,799	0	15,799	0	9
10	Less: Wholesale Allocation of Increase-FERC	2,376	643	(1,734)	977	(334)	10
	[(Line 8 - Line 7) x Line 6 / Line 7]						
11	Required Retail Revenue	3,631,413	3,287,404	(344,009)	3,250,282	37,122	11
12	Less: Proposed Other Operating Revenue-CPUC	97,880	97,880	0	99,702	(1,822)	12
13	Total Proposed Retail Revenue Requirement	3,533,533	3,189,524	(344,009)	3,150,580	38,944	13
	Increase in Proposed Revenue Over Adopted Revenue						
14	Proposed Retail Revenue Requirement (Line 13)	3,533,533	3,189,524	(344,009)	3,150,580	38,944	14
15	Less: Adopted Retail Revenue (Line 1)	3,007,541	3,007,541	0	3,007,000	541	15
16	Increase in Retail Revenue Requirement over Adopted Revenue	525,992	181,983	(344,009)	143,580	38,403	16

Wholesale Wheeling & Resale Revenue (line 4) and Wholesale Allocation of Increase-FERC (line 10) are attributable only to ED - Wires and Services.

Table 1-2

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Results of Operations at Proposed Rates
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	3,533,533	3,189,524	(344,009)	3,150,580	38,944	1
2	Plus Other Operating Revenue	116,055	114,321	(1,734)	116,477	(2,156)	2
3	Total Operating Revenue	3,649,588	3,303,846	(345,742)	3,267,058	36,788	3
	OPERATING EXPENSES:						
4	Energy Costs	0	0	0	0	0	4
5	Production	0	0	0	0	0	5
6	Storage	0	0	0	0	0	6
7	Transmission	1,137	1,137	0	1,122	16	7
8	Distribution	626,077	570,310	(55,767)	485,063	85,247	8
9	Customer Accounts	280,259	187,347	(92,912)	226,680	(39,333)	9
10	Uncollectibles	10,393	10,240	(153)	8,632	1,608	10
11	Customer Services	9,600	4,153	(5,446)	4,132	22	11
12	Administrative and General	431,232	386,453	(44,779)	323,422	63,032	12
13	Franchise Requirements	27,584	24,965	(2,619)	24,698	267	13
14	Amortization	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	16
17	Other Adjustments	0	(44,000)	(44,000)	0	(44,000)	17
18	Subtotal Expenses:	1,386,282	1,140,606	(245,677)	1,073,749	66,857	18
	TAXES:						
19	Superfund	0	0	0	0	0	19
20	Property	129,822	129,822	0	127,903	1,919	20
21	Payroll	47,870	41,427	(6,443)	37,323	4,104	21
22	Business	508	508	0	508	0	22
23	Other	1,171	1,171	0	2,214	(1,043)	23
24	State Corporation Franchise	63,913	57,649	(6,264)	63,383	(5,734)	24
25	Federal Income	272,257	269,149	(3,108)	271,107	(1,958)	25
26	Total Taxes	515,541	499,726	(15,814)	502,439	(2,712)	26
27	Depreciation	849,568	776,287	(73,281)	820,549	(44,262)	27
28	Fossil Decommissioning	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	29
30	Total Operating Expenses	2,751,391	2,416,619	(334,772)	2,396,736	19,883	30
31	Net for Return	898,197	887,226	(10,971)	870,322	16,905	31
32	Rate Base	10,218,396	10,093,589	(124,807)	9,901,269	192,320	32
	RATE OF RETURN:						
33	On Rate Base	**8.79%**	**8.79%**		**8.79%**		33
34	On Equity	**11.35%**	**11.35%**		**11.35%**		34

Table 1-3

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Income Taxes at Proposed Rates
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
1	Revenues	3,649,588	3,303,846	(345,742)	3,267,058	36,788	1
2	O&M Expenses	1,386,282	1,140,606	(245,677)	1,073,749	66,857	2
3	Nuclear Decommissioning Expense	0	0	0	0	0	3
4	Superfund Tax	0	0	0	0	0	4
5	Taxes Other Than Income	179,371	172,928	(6,443)	167,948	4,980	5
6	Subtotal	2,083,935	1,990,312	(93,623)	2,025,361	(35,049)	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	284,071	280,602	(3,470)	275,255	5,347	7
8	Fiscal/Calendar Adjustment	3,510	3,510	0	2,397	1,113	8
9	Operating Expense Adjustments	(21,890)	(21,991)	(101)	(19,532)	(2,459)	9
10	Capitalized Interest Adjustment	0	0	0	0	0	10
11	Capitalized Inventory Adjustment	0	0	0	0	0	11
12	Vacation Accrual Reduction	(1,535)	(1,535)	0	(1,535)	0	12
13	Capitalized Other	5,408	5,408	0	5,129	278	13
14	Subtotal Deductions	269,564	265,993	(3,570)	261,714	4,279	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	2,420	2,420	0	2,420	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	0	0	16
17	State Tax Depreciation - Fixed Assets	847,558	838,375	(9,183)	804,303	34,072	17
18	State Tax Depreciation - Other	0	0	0	0	0	18
19	Removal Costs	107,960	100,093	(7,867)	112,671	(12,577)	19
20	Repair Allowance	91,497	89,351	(2,146)	85,305	4,046	20
21	Subtotal Deductions	1,318,999	1,296,232	(22,767)	1,266,413	29,819	21
22	Taxable Income for CCFT	764,936	694,080	(70,857)	758,948	(64,869)	22
23	CCFT	67,620	61,357	(6,264)	67,091	(5,734)	23
24	State Tax Adjustment	0	0	0	0	0	24
25	Current CCFT	67,620	61,357	(6,264)	67,091	(5,734)	25
26	Deferred Taxes - Reg Asset	0	0	0	0	0	26
27	Deferred Taxes - Interest	214	214	0	214	0	27
28	Deferred Taxes - Vacation	(136)	(136)	0	(136)	0	28
29	Deferred Taxes - Other	0	0	0	0	0	29
30	Deferred Taxes - Fixed Assets	(3,786)	(3,786)	0	(3,786)	0	30
31	Total CCFT	63,913	57,649	(6,264)	63,383	(5,734)	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	46,473	46,559	87	54,094	(7,535)	32
33	Federal Operating Expense Adjustment	4,864	4,864	0	4,864	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	774,806	756,156	(18,650)	725,295	30,861	36
37	Federal Tax Depreciation - Other	0	0	0	0	0	37
38	Removal Costs	107,960	100,093	(7,867)	112,671	(12,577)	38
39	Repair Allowance	13,555	13,237	(318)	11,679	1,558	39
40	Preferred Dividend Credit	306	306	0	306	0	40
41	Subtotal Deductions	1,217,528	1,187,210	(30,318)	1,170,624	16,586	41
42	Taxable Income for FIT	866,407	803,102	(63,305)	854,737	(51,636)	42
43	Federal Income Tax	303,242	281,086	(22,157)	299,158	(18,072)	43
44	Deferred Taxes - Reg Asset	0	0	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	45
46	Deferred Taxes - Interest	781	781	0	781	0	46
47	Deferred Taxes - Vacation	(490)	(490)	0	(490)	0	47
48	Deferred Taxes - Other	(9,109)	(9,109)	0	0	(9,109)	48
49	Deferred Taxes - Fixed Assets	(22,167)	(3,119)	19,049	(28,342)	25,223	49
50	Total Federal Income Tax	272,257	269,149	(3,108)	271,107	(1,958)	50

Table 1-4

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Total Escalation
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Total Escalated						
1	Energy Cost	0	0	0	0	0	1
2	Production	0	0	0	0	0	2
3	Storage	0	0	0	0	0	3
4	Transmission	1,137	1,137	0	1,122	16	4
5	Distribution	626,077	570,310	(55,767)	485,063	85,247	5
6	Customer Accounts	280,259	187,347	(92,912)	226,680	(39,333)	6
7	Customer Services	9,600	4,153	(5,446)	4,132	22	7
8	Administrative and General	410,617	365,838	(44,779)	310,659	55,179	8
9	Other	0	(44,000)	(44,000)	0	(44,000)	9
10	Total Escalated	1,327,690	1,084,786	(242,904)	1,027,656	57,130	10
11	Wage Related A&G Escalated	20,615	20,615	0	12,763	7,853	11
	Total Non-Escalated						
12	Energy Cost	0	0	0	0	0	12
13	Production	0	0	0	0	0	13
14	Storage	0	0	0	0	0	14
15	Transmission	1,052	1,052	0	1,052	0	15
16	Distribution	587,058	532,333	(54,725)	458,125	74,208	16
17	Customer Accounts	252,247	168,099	(84,148)	206,327	(38,228)	17
18	Customer Services	8,648	3,750	(4,898)	3,758	(8)	18
19	Administrative and General	385,177	342,937	(42,240)	292,318	50,619	19
20	Other	0	(44,000)	(44,000)	(2,251)	(41,749)	20
21	Total Non-Escalated	1,234,182	1,004,171	(230,011)	959,328	44,843	21
22	Wage Related A&G Non-Escalated	18,460	18,460	0	11,428	7,032	22
	Total Escalation						
23	Energy Cost	0	0	0	0	0	23
24	Production	0	0	0	0	0	24
25	Storage	0	0	0	0	0	25
26	Transmission	86	86	0	70	16	26
27	Distribution	39,019	37,977	(1,042)	26,938	11,039	27
28	Customer Accounts	28,012	19,248	(8,764)	20,353	(1,105)	28
29	Customer Services	952	403	(549)	374	29	29
30	Administrative and General	25,440	22,901	(2,539)	18,342	4,559	30
31	Other	0	0	0	2,251	(2,251)	31
32	Total Escalation	93,507	80,615	(12,893)	68,327	12,287	32
33	Wage Related A&G Escalation	2,156	2,156	0	1,334	821	33
34	Acct 926 M&S - Empl Pensions & Benefits	0	0	0	0	0	34
35	Acct 924 Other - Property Insurance	7,624	7,624	0	7,624	0	35
36	Acct 926 Other - Empl Pensions & Benefits	0	0	0	0	0	36

Table 1-5

Pacific Gas and Electric Company

2011 PG&E GRC (SETTLEMENT)

Franchise and Uncollectibles at Proposed Rates
Electric Distribution

$(000)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Uncollectible Accounts						
1	Rate Case Revenues	3,649,588	3,303,846	(345,742)	3,267,058	36,788	1
2	Percent of Revenue from Customers	0.998200	0.998200	0.000000	0.998200	0.000000	2
3	Rate Case Revenues from Customers	3,643,019	3,297,899	(345,120)	3,261,177	36,722	3
4	Uncollectible Rate	0.00285	0.00311	0.00025	0.00265	0.00046	4
5	Uncollectible Accounts Expense	10,393	10,240	(153)	8,632	1,608	5
	Franchise Fees						
6	Rate Case Revenues from Customers	3,643,019	3,297,899	(345,120)	3,261,177	36,722	6
7	Uncollectible Accounts Expense	10,393	10,240	(153)	8,632	1,608	7
8	Net Rate Case Revenue from Customers	3,632,626	3,287,659	(344,967)	3,252,545	35,114	8
9	Franchise Rate	0.00759	0.00759	0.00000	0.00759	0.00000	9
10	Franchise Fees Expense	27,584	24,965	(2,619)	24,698	267	10

Table 1-6

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Payroll and Other Taxes
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Property (Ad Valorem) Tax:						
1	Fiscal Year Tax	133,332	133,332	0	130,300	3,032	1
2	Calendar Year Tax	129,822	129,822	0	127,903	1,919	2
	Payroll Taxes						
3	Federal Insurance Contribution Act (FICA)	41,401	35,822	(5,578)	32,303	3,519	3
4	Federal Unemployment Insurance (FUI)	404	350	(55)	316	34	4
5	State Unemployment Insurance (SUI)	2,225	1,925	(300)	1,736	189	5
6	San Francisco Employee Tax	3,840	3,330	(510)	2,968	361	6
7	Total Payroll Taxes	47,870	41,427	(6,443)	37,323	4,104	7
	Other Taxes						
8	Business	508	508	0	508	0	8
9	Hazardous Waste	0	0	0	0	0	9
10	Windfall Profits	0	0	0	0	0	10
11	Other	1,171	1,171	0	2,214	(1,043)	11
12	Total Other Taxes	1,679	1,679	0	2,722	(1,043)	12
13	Total Taxes Other Than Income	179,371	172,928	(6,443)	167,948	4,980	13

Table 1-7

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Plant In Service - Test Year 2011
Electric Distribution
(Thousands of Dollars)

		Annual Plant in Service					Weighted Average Plant in Service					
Line No.	Description	PG&E Position (A)	SETTLEMENT Position (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	PG&E Position (F)	SETTLEMENT Position (G)	Difference SETTLEMENT v PG&E (H) = (G)-(F)	DRA 2011 (I)	Difference SETTLEMENT v DRA (J)=(G)-(I)	Line No.
	Year 2008											
1	Total End-of-Year Plant	18,466,658	18,466,658	0	18,466,658	0	17,986,753	17,986,753	0	17,986,753	0	1
	Year 2009											
2	Total Full-Year Net Additions	679,275	679,275	0	613,232	66,043	332,522	332,522	0	298,228	34,295	2
3	Total End-of-Year Plant	19,145,933	19,145,933	0	19,079,890	66,043	18,799,180	18,799,180	0	18,764,886	34,295	3
	Year 2010											
4	Total Full-Year Net Additions	827,695	827,695	0	666,252	161,443	372,692	372,692	0	277,723	94,969	4
5	Total End-of-Year Plant	19,973,628	19,973,628	0	19,746,142	227,486	19,518,625	19,518,625	0	19,357,613	161,012	5
	Year 2011											
6	Total Full-Year Net Additions	1,068,974	956,855	(112,120)	795,966	160,889	471,539	363,812	(107,727)	344,583	19,228	6
7	Total End-of-Year Plant	21,042,602	20,930,483	(112,120)	20,542,108	388,375	20,445,167	20,337,440	(107,727)	20,090,726	246,714	7

Table 1-8

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Depreciation
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Depreciation						
1	Annual	849,568	776,287	(73,281)	820,549	(44,262)	1
2	Reserve	8,968,612	8,918,989	(49,623)	8,922,198	(3,210)	2
3	Weighted Average Reserve	8,766,948	8,748,990	(17,958)	8,717,118	31,872	3

Table 1-9

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Working Cash Capital
Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Operational Cash Requirements:						
1	Required Bank Balances	0	0	0	0	0	1
2	Special Deposits and Working Funds	71	70	(0)	71	(0)	2
3	Other Receivables	40,738	40,674	(64)	40,957	(283)	3
4	Prepayments	22,521	22,521	0	23,141	(620)	4
5	Deferred Debits, Company-Wide	(70)	(70)	0	(74)	4	5
	Less:						
6	Working Cash Capital not Supplied by Investors	5,414	5,414	0	5,848	(434)	6
7	Goods Delivered to Construction Sites	6,466	6,466	0	6,466	0	7
8	Accrued Vacation	75,010	64,903	(10,107)	58,526	6,376	8
	Add:						
9	Prepayment, Departmental	0	0	0	0	0	9
10	Total Operational Cash Requirement	(23,631)	(13,587)	10,043	(6,746)	(6,841)	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	51,395	46,918	(4,477)	38,521	8,398	11
12	Working Cash Capital Supplied by Investors	27,764	33,331	5,567	31,774	1,557	12

Table 1-10

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Ratebase
Electric Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	19,973,628	19,973,628	0	19,746,142	227,486	1
2	Net Additions	471,539	363,812	(107,727)	344,583	19,228	4
3	Total Weighted Average Plant	20,445,167	20,337,440	(107,727)	20,090,726	246,714	5
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	0	0	0	0	0	6
5	Material and Supplies - Other	74,827	74,827	0	63,954	10,873	7
6	Working Cash	27,764	33,331	5,567	31,774	1,557	8
7	Total Working Capital	102,591	108,158	5,567	95,728	12,430	9
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	775	775	0	775	0	10
9	Deferred Vacation	18,660	18,660	0	18,660	0	11
10	Deferred CIAC Tax Effects	302,984	302,984	0	302,984	0	12
11	Total Adjustments	322,418	322,418	0	322,418	0	13
12	CUSTOMER ADVANCES	89,342	89,342	0	89,342	0	14
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	0	0	0	0	0	15
14	Accumulated Fixed Assets	1,774,457	1,815,061	40,604	1,756,498	58,562	16
15	Accumulated Other	(23,611)	(23,611)	0	0	(23,611)	17
16	Deferred ITC	44,645	44,645	0	44,645	0	18
17	Deferred Tax - Other	0	0	0	0	0	19
18	Total Deferred Taxes	1,795,490	1,836,094	40,604	1,801,143	34,951	20
19	DEPRECIATION RESERVE	8,766,948	8,748,990	(17,958)	8,717,118	31,872	21
20	TOTAL Ratebase	10,218,396	10,093,589	(124,807)	9,901,269	192,320	22

Table 1-11

PG&E

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

PG&E Final Position - Electric Department

Line No.	Description	Component (A)	Post Deduction Revenue (B)	Cumulative Components (C)	Net-To Gross Multiplier (D)	Line No.
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.002853	0.997152	0.002848	1.002856	2
3	Franchise Requirements	0.007593	0.989594	0.007558	1.010515	3
4	Super Fund Tax	0.000000	0.989594	0.000000	1.010515	4
5	State Income Tax	0.088400	0.902114	0.087480	1.108507	5
6	Federal Income Tax	0.350000	0.555756	0.346358	1.799351	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 1-12

SETTLEMENT

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

SETTLEMENT - Position Electric Department

Line No.	Description	Component	Post Deduction Revenue	Cumulative Components	Net-To Gross Multiplier	Line No.
		(A)	(B)	(C)	(D)	
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.003105	0.996901	0.003099	1.003109	2
3	Franchise Requirements	0.007593	0.989344	0.007556	1.010770	3
4	Super Fund Tax	0.000000	0.989344	0.000000	1.010770	4
5	State Income Tax	0.088400	0.901886	0.087458	1.108787	5
6	Federal Income Tax	0.350000	0.555616	0.346271	1.799805	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 1-13

DRA

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

DRA Final Position - Electric Department

Line No.	Description	Component	Post Deduction Revenue	Cumulative Components	Net-To Gross Multiplier	Line No.
		(A)	(B)	(C)	(D)	
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.002647	0.997358	0.002642	1.002649	2
3	Franchise Requirements	0.007593	0.989798	0.007560	1.010307	3
4	Super Fund Tax	0.000000	0.989798	0.000000	1.010307	4
5	State Income Tax	0.088400	0.902300	0.087498	1.108279	5
6	Federal Income Tax	0.350000	0.555871	0.346429	1.798980	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 2-1

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

General Rate Case Revenues: Gas Distribution

Available from Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUES AT PRESENT RATES						
	CPUC Revenues (Retail)						
1	Retail Revenue Collected in Rates	1,084,066	1,084,066	0	1,084,000	66	1
2	Plus: Other Operating Revenue (Adopted in GRC)	26,024	26,024	0	26,024	0	2
3	Total CPUC Jurisdiction Revenue	1,110,090	1,110,090	0	1,110,024	66	3
	FERC Jurisdiction Wholesale Revenue						
4	Wholesale Wheeling & Resale Revenue	0	0	0	0	0	4
5	Plus: Wholesale Other Operating Revenue	0	0	0	0	0	5
6	Total Wholesale Revenue	0	0	0	0	0	6
7	Total Operating Revenue (Present)	1,110,090	1,110,090	0	1,110,024	66	7
	REVENUES AT PROPOSED RATES						
8	Revenue Requirement	1,315,666	1,154,351	(161,315)	1,095,451	58,900	8
	(Test Year 2011, line 3, tab RO_Proposed)						
9	Less: Total Wholesale Revenue-FERC (Line 6)	0	0	0	0	0	9
10	Less: Wholesale Allocation of Increase-FERC	0	0	0	0	0	10
	[(Line 8 - Line 7) x Line 6 / Line 7]						
11	Required Retail Revenue	1,315,666	1,154,351	(161,315)	1,095,451	58,900	11
12	Less: Proposed Other Operating Revenue-CPUC	22,922	22,922	0	23,338	(416)	12
13	Total Proposed Retail Revenue Requirement	1,292,744	1,131,429	(161,315)	1,072,113	59,316	13
	Increase in Proposed Revenue Over Adopted Revenue						
14	Proposed Retail Revenue Requirement (Line 13)	1,292,744	1,131,429	(161,315)	1,072,113	59,316	14
15	Less: Adopted Retail Revenue (Line 1)	1,084,066	1,084,066	0	1,084,000	66	15
16	Increase in Retail Revenue Requirement over Adopted Revenue	208,678	47,363	(161,315)	(11,887)	59,250	16

Table 2-2

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Results of Operations at Proposed Rates
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	1,292,744	1,131,429	(161,315)	1,072,113	59,316	1
2	Plus Other Operating Revenue	22,922	22,922	0	23,338	(416)	2
3	Total Operating Revenue	1,315,666	1,154,351	(161,315)	1,095,451	58,900	3
	OPERATING EXPENSES:						
4	Energy Costs	0	0	0	0	0	4
5	Gathering	0	0	0	0	0	5
6	Storage	3,565	3,565	0	2,664	901	6
7	Transmission	0	0	0	0	0	7
8	Distribution	225,618	192,076	(33,543)	139,726	52,350	8
9	Customer Accounts	202,987	132,594	(70,393)	163,768	(31,174)	9
10	Uncollectibles	3,664	3,499	(165)	2,831	668	10
11	Customer Services	5,315	5,049	(266)	5,008	42	11
12	Administrative and General	211,721	189,736	(21,985)	158,790	30,946	12
13	Franchise Requirements	12,538	10,998	(1,540)	10,442	556	13
14	Amortization	0	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	16
17	Other Adjustments	0	0	0	0	0	17
18	Subtotal Expenses:	665,409	537,518	(127,891)	483,228	54,290	18
	TAXES:						
19	Superfund	0	0	0	0	0	19
20	Property	29,493	29,493	0	29,269	223	20
21	Payroll	27,758	22,832	(4,926)	20,720	2,112	21
22	Business	250	250	0	250	0	22
23	Other	575	575	0	1,087	(512)	23
24	State Corporation Franchise	20,295	18,079	(2,216)	18,707	(628)	24
25	Federal Income	67,564	66,061	(1,503)	63,611	2,451	25
26	Total Taxes	145,934	137,290	(8,645)	133,644	3,646	26
27	Depreciation	288,216	264,319	(23,897)	269,237	(4,918)	27
28	Fossil Decommissioning	0	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	0	29
30	Total Operating Expenses	1,099,559	939,126	(160,433)	886,109	53,017	30
31	Net for Return	216,107	215,225	(882)	209,342	5,883	31
32	Rate Base	2,458,553	2,448,519	(10,034)	2,381,593	66,926	32
	RATE OF RETURN:						
33	On Rate Base	**8.79%**	**8.79%**		**8.79%**		33
34	On Equity	**11.35%**	**11.35%**		**11.35%**		34

Table 2-3

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Income Taxes at Proposed Rates
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
1	Revenues	1,315,666	1,154,351	(161,315)	1,095,451	58,900	1
2	O&M Expenses	665,409	537,518	(127,891)	483,228	54,290	2
3	Nuclear Decommissioning Expense	0	0	0	0	0	3
4	Superfund Tax	0	0	0	0	0	4
5	Taxes Other Than Income	58,075	53,149	(4,926)	51,326	1,823	5
6	Subtotal	592,182	563,684	(28,497)	560,897	2,787	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	68,348	68,069	(279)	66,208	1,861	7
8	Fiscal/Calendar Adjustment	557	557	0	221	336	8
9	Operating Expense Adjustments	(11,332)	(11,319)	13	(9,932)	(1,387)	9
10	Capitalized Interest Adjustment	0	0	0	0	0	10
11	Capitalized Inventory Adjustment	0	0	0	0	0	11
12	Vacation Accrual Reduction	(850)	(850)	0	(850)	0	12
13	Capitalized Other	3,572	3,572	0	3,648	(76)	13
14	Subtotal Deductions	60,295	60,030	(266)	59,295	734	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	292	292	0	292	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	0	0	16
17	State Tax Depreciation - Fixed Assets	257,994	254,924	(3,069)	243,485	11,439	17
18	State Tax Depreciation - Other	0	0	0	0	0	18
19	Removal Costs	20,782	20,689	(92)	22,971	(2,282)	19
20	Repair Allowance	0	0	0	0	0	20
21	Subtotal Deductions	339,363	335,935	(3,428)	326,044	9,892	21
22	Taxable Income for CCFT	252,819	227,749	(25,070)	234,854	(7,105)	22
23	CCFT	22,349	20,133	(2,216)	20,761	(628)	23
24	State Tax Adjustment	0	0	0	0	0	24
25	Current CCFT	22,349	20,133	(2,216)	20,761	(628)	25
26	Deferred Taxes - Reg Asset	0	0	0	0	0	26
27	Deferred Taxes - Interest	26	26	0	26	0	27
28	Deferred Taxes - Vacation	(75)	(75)	0	(75)	0	28
29	Deferred Taxes - Other	0	0	0	0	0	29
30	Deferred Taxes - Fixed Assets	(2,005)	(2,005)	0	(2,005)	0	30
31	Total CCFT	20,295	18,079	(2,216)	18,707	(628)	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	15,533	15,554	21	18,987	(3,432)	32
33	Federal Operating Expense Adjustment	781	781	0	781	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	260,709	254,411	(6,298)	242,039	12,372	36
37	Federal Tax Depreciation - Other	0	0	0	0	0	37
38	Removal Costs	20,782	20,689	(92)	22,971	(2,282)	38
39	Repair Allowance	0	0	0	0	0	39
40	Preferred Dividend Credit	43	43	0	43	0	40
41	Subtotal Deductions	358,143	351,508	(6,635)	344,115	7,393	41
42	Taxable Income for FIT	234,039	212,176	(21,863)	216,782	(4,606)	42
43	Federal Income Tax	81,914	74,262	(7,652)	75,874	(1,612)	43
44	Deferred Taxes - Reg Asset	0	0	0	0	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	0	0	45
46	Deferred Taxes - Interest	162	162	0	162	0	46
47	Deferred Taxes - Vacation	(271)	(271)	0	(271)	0	47
48	Deferred Taxes - Other	(2,024)	(2,024)	0	0	(2,024)	48
49	Deferred Taxes - Fixed Assets	(12,216)	(6,067)	6,149	(12,154)	6,087	49
50	Total Federal Income Tax	67,564	66,061	(1,503)	63,611	2,451	50

Table 2-4

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Total Escalation
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Total Escalated						
1	Energy Cost	0	0	0	0	0	1
2	Gathering	0	0	0	0	0	2
3	Storage	3,565	3,565	0	2,664	901	3
4	Transmission	0	0	0	0	0	4
5	Distribution	225,618	192,076	(33,543)	139,726	52,350	5
6	Customer Accounts	202,987	132,594	(70,393)	163,768	(31,174)	6
7	Customer Services	5,315	5,049	(266)	5,008	42	7
8	Administrative and General	201,599	179,615	(21,985)	152,524	27,091	8
9	Other	0	0	0	0	0	9
10	Total Escalated	639,084	512,899	(126,186)	463,689	49,209	10
11	Wage Related A&G Escalated	10,121	10,121	0	6,266	3,855	11
	Total Non-Escalated						
12	Energy Cost	0	0	0	0	0	12
13	Gathering	0	0	0	0	0	13
14	Storage	3,216	3,216	0	2,450	766	14
15	Transmission	0	0	0	0	0	15
16	Distribution	205,895	173,335	(32,559)	129,325	44,010	16
17	Customer Accounts	182,733	119,296	(63,437)	149,060	(29,764)	17
18	Customer Services	4,795	4,556	(238)	4,555	1	18
19	Administrative and General	189,109	168,371	(20,739)	143,518	24,852	19
20	Other	0	0	0	0	0	20
21	Total Non-Escalated	585,747	468,774	(116,973)	428,908	39,866	21
22	Wage Related A&G Non-Escalated	9,063	9,063	0	5,611	3,452	22
	Total Escalation						
23	Energy Cost	0	0	0	0	0	23
24	Gathering	0	0	0	0	0	24
25	Storage	350	350	0	214	135	25
26	Transmission	0	0	0	0	0	26
27	Distribution	19,724	18,740	(983)	10,401	8,339	27
28	Customer Accounts	20,254	13,298	(6,956)	14,708	(1,410)	28
29	Customer Services	520	493	(27)	452	41	29
30	Administrative and General	12,490	11,244	(1,246)	9,005	2,239	30
31	Other	0	0		0	0	31
32	Total Escalation	53,337	44,124	(9,213)	34,781	9,343	32
33	Wage Related A&G Escalation	1,058	1,058	0	655	403	33
34	Acct 926 M&S - Empl Pensions & Benefits	0	0	0	0	0	34
35	Acct 924 Other - Property Insurance	3,743	3,743	0	3,743	0	35
36	Acct 926 Other - Empl Pensions & Benefits	0	0	0	0	0	36

Table 2-5

Pacific Gas and Electric Company

2011 PG&E GRC (SETTLEMENT)

Franchise and Uncollectibles at Proposed Rates
Gas Distribution

$(000)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	DRA Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Uncollectible Accounts						
1	Rate Case Revenues	1,315,666	1,154,351	(161,315)	1,095,451	58,900	1
2	Percent of Revenue from Customers	0.976300	0.976300	0.000000	0.976300	0.000000	2
3	Rate Case Revenues from Customers	1,284,484	1,126,993	(157,491)	1,069,489	57,504	3
4	Uncollectible Rate	0.00285	0.00311	0.00025	0.00265	0.00046	4
5	Uncollectible Accounts Expense	3,664	3,499	(165)	2,831	668	5
	Franchise Fees						
12	Rate Case Revenues from Customers	1,284,484	1,126,993	(157,491)	1,069,489	57,504	12
13	Uncollectible Accounts Expense	3,664	3,499	(165)	2,831	668	13
14	Net Rate Case Revenue from Customers	1,280,820	1,123,494	(157,326)	1,066,658	56,835	14
						0	
15	Franchise Rate	0.00979	0.00979	0.00000	0.00979	0.00000	15
16	Franchise Fees Expense	12,538	10,998	(1,540)	10,442	556	16

Table 2-6

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Payroll and Other Taxes
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Property (Ad Valorem) Tax:						
1	Fiscal Year Tax	30,050	30,050	0	29,490	560	1
2	Calendar Year Tax	29,493	29,493	0	29,269	223	2
	Payroll Taxes						
3	Federal Insurance Contribution Act (FICA)	24,189	19,883	(4,306)	18,083	1,800	3
4	Federal Unemployment Insurance (FUI)	236	194	(42)	177	18	4
5	State Unemployment Insurance (SUI)	1,300	1,068	(231)	972	97	5
6	San Francisco Employee Tax	2,033	1,686	(347)	1,488	197	6
7	Total Payroll Taxes	27,758	22,832	(4,926)	20,720	2,112	7
	Other Taxes						
8	Business	250	250	0	250	0	8
9	Hazardous Waste	0	0	0	0	0	9
10	Windfall Profits	0	0	0	0	0	10
11	Other	575	575	0	1,087	(512)	11
12	Total Other Taxes	825	825	0	1,337	(512)	12
13	Total Taxes Other Than Income	58,075	53,149	(4,926)	51,326	1,823	13

Table 2-7

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Plant In Service - Test Year 2011
Gas Distribution
(Thousands of Dollars)

		Annual Plant in Service					Weighted Average Plant in Service					
Line No.	Description	PG&E Position (A)	SETTLEMENT Position (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	PG&E Position (F)	SETTLEMENT Position (G)	Difference SETTLEMENT v PG&E (H) = (G)-(F)	DRA 2011 (I)	Difference SETTLEMENT v DRA (J)=(G)-(I)	Line No.
	Year 2008											
1	Total End-of-Year Plant	6,341,708	6,341,708	0	6,341,708	0	6,241,770	6,241,770	0	6,241,770	0	1
	Year 2009											
2	Total Full-Year Net Additions	217,960	217,960	0	226,090	(8,130)	108,141	108,141	0	112,626	(4,485)	2
3	Total End-of-Year Plant	6,559,668	6,559,668	0	6,567,798	(8,130)	6,449,848	6,449,848	0	6,454,333	(4,485)	3
	Year 2010											
4	Total Full-Year Net Additions	229,141	229,141	0	172,341	56,800	108,466	108,466	0	78,412	30,054	4
5	Total End-of-Year Plant	6,788,808	6,788,808	0	6,740,138	48,670	6,668,134	6,668,134	0	6,646,210	21,924	5
	Year 2011											
6	Total Full-Year Net Additions	289,084	275,956	(13,128)	205,636	70,320	137,598	124,592	(13,007)	97,352	27,239	6
7	Total End-of-Year Plant	7,077,892	7,064,765	(13,128)	6,945,774	118,990	6,926,406	6,913,400	(13,007)	6,837,490	75,909	7

Table 2-8

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Depreciation
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Depreciation						
1	Annual	288,216	264,319	(23,897)	269,237	(4,918)	1
2	Reserve	4,363,291	4,344,831	(18,460)	4,349,311	(4,480)	2
3	Weighted Average Reserve	4,269,873	4,261,071	(8,802)	4,257,851	3,220	3

Table 2-9

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Working Cash Capital
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Operational Cash Requirements:						
1	Required Bank Balances	0	0	0	0	0	1
2	Special Deposits and Working Funds	35	35	(0)	35	0	2
3	Other Receivables	20,445	20,422	(23)	20,431	(9)	3
4	Prepayments	11,057	11,057	0	11,361	(304)	4
5	Deferred Debits, Company-Wide	(38)	(37)	0	(39)	1	5
	Less:						
6	Working Cash Capital not Supplied by Investors	2,658	2,658	0	2,871	(213)	6
7	Goods Delivered to Construction Sites	3,175	3,175	0	3,175	0	7
8	Accrued Vacation	43,826	36,024	(7,801)	32,763	3,261	8
	Add:						
9	Prepayment, Departmental	0	0	0	0	0	9
10	Total Operational Cash Requirement	(18,159)	(10,381)	7,778	(7,020)	(3,360)	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	26,866	23,669	(3,197)	19,164	4,505	11
12	Working Cash Capital Supplied by Investors	8,708	13,288	4,581	12,144	1,144	12

Table 2-10

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Ratebase
Gas Distribution
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	6,788,808	6,788,808	0	6,740,138	48,670	1
2	Net Additions	137,598	124,592	(13,007)	97,352	27,239	4
3	Total Weighted Average Plant	6,926,406	6,913,400	(13,007)	6,837,490	75,909	5
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	0	0	0	0	0	6
5	Material and Supplies - Other	6,503	6,503	0	6,038	465	7
6	Working Cash	8,708	13,288	4,581	12,144	1,144	8
7	Total Working Capital	15,211	19,792	4,581	18,182	1,609	9
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	(277)	(277)	0	(277)	0	10
9	Deferred Vacation	10,330	10,330	0	10,330	0	11
10	Deferred CIAC Tax Effects	127,805	127,805	0	127,805	0	12
11	Total Adjustments	137,857	137,857	0	137,857	0	13
12	CUSTOMER ADVANCES	39,310	39,310	0	39,310	0	14
				0			
	DEFERRED TAXES			0			
13	Accumulated Regulatory Assets	0	0	0	0	0	15
14	Accumulated Fixed Assets	293,718	304,128	10,410	293,507	10,621	16
15	Accumulated Other	(3,249)	(3,249)	0	0	(3,249)	17
16	Deferred ITC	21,269	21,269	0	21,269	0	18
17	Deferred Tax - Other	0	0	0	0	0	19
18	Total Deferred Taxes	311,738	322,148	10,410	314,776	7,372	20
				0			
19	DEPRECIATION RESERVE	4,269,873	4,261,071	(8,802)	4,257,851	3,220	21
				0			
20	TOTAL Ratebase	2,458,553	2,448,519	(10,034)	2,381,593	66,926	22

Table 2-11

PG&E

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

PG&E Final Position - Gas Department

Line No.	Description	Component (A)	Post Deduction Revenue (B)	Cumulative Components (C)	Net-To Gross Multiplier (D)	Line No.
	Including F&U					
1	Gross Operating Revenue		1.000000	0.976300		1
	Less:					
2	Uncollectible Accounts	0.002853	0.997215	0.002785	1.002793	2
3	Franchise Requirements	0.009789	0.987685	0.009530	1.012469	3
4	Super Fund Tax	0.000000	0.987685	0.000000	1.012469	4
5	State Income Tax	0.088400	0.900373	0.087311	1.110650	5
6	Federal Income Tax	0.350000	0.554684	0.345690	1.802829	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 2-12

SETTLEMENT

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

SETTLEMENT - Gas Department

Line No.	Description	Component	Post Deduction Revenue	Cumulative Components	Net-To Gross Multiplier	Line No.
		(A)	(B)	(C)	(D)	
	Including F&U					
1	Gross Operating Revenue		1.000000	0.976300		1
	Less:					
2	Uncollectible Accounts	0.003105	0.996969	0.003031	1.003041	2
3	Franchise Requirements	0.009789	0.987441	0.009528	1.012719	3
4	Super Fund Tax	0.000000	0.987441	0.000000	1.012719	4
5	State Income Tax	0.088400	0.900151	0.087290	1.110925	5
6	Federal Income Tax	0.350000	0.554547	0.345604	1.803274	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 2-13

DRA

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

DRA Final Position - Gas Department

Line No.	Description	Component	Post Deduction Revenue	Cumulative Components	Net-To Gross Multiplier	Line No.
		(A)	(B)	(C)	(D)	
	Including F&U					
1	Gross Operating Revenue		1.000000	0.976300		1
	Less:					
2	Uncollectible Accounts	0.002647	0.997416	0.002584	1.002591	2
3	Franchise Requirements	0.009789	0.987884	0.009532	1.012265	3
4	Super Fund Tax	0.000000	0.987884	0.000000	1.012265	4
5	State Income Tax	0.088400	0.900555	0.087329	1.110427	5
6	Federal Income Tax	0.350000	0.554795	0.345759	1.802466	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 3-1

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

General Rate Case Revenues: Electric Generation

Available from Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUES ADOPTED and PENDING						
	CPUC Jurisdiction Revenue						
1	Retail Revenue Collected in Rates	1,490,498	1,490,498	0	1,490,498	0	1
2	Plus: Other Operating Revenue (Adopted in GRC)	10,120	10,120	0	10,120	0	2
3	Total CPUC Jurisdiction Revenue	1,500,618	1,500,618	0	1,500,618	0	3
	FERC Jurisdiction Wholesale Revenue						
4	Wholesale Wheeling & Resale Revenue	27	27	0	27	0	4
5	Plus: Wholesale Other Operating Revenue	0	0	0	0	0	5
6	Total Wholesale Revenue	27	27	0	27	0	6
7	Total Operating Revenue (Present)	1,500,645	1,500,645	0	1,500,645	0	7
	REVENUES AT PROPOSED RATES						
8	Revenue Requirement	1,831,379	1,667,848	(163,531)	1,551,488	116,360	8
	(Test Year 2011, line 3, tab RO_Proposed)						
9	Less: Total Wholesale Revenue-FERC (Line 6)	27	27	0	27	0	9
10	Less: Wholesale Allocation of Increase-FERC	12	10	(2)	6	4	10
	[(Line 8 - Line 7) x Line 6 / Line 7]						
11	Required Retail Revenue	1,831,340	1,667,810	(163,529)	1,551,455	116,355	11
12	Less: Proposed Other Operating Revenue-CPUC	11,608	11,608	0	11,608	0	12
13	Total Proposed Retail Revenue Requirement	1,819,732	1,656,202	(163,529)	1,539,847	116,355	13
	Increase in Proposed Revenue Over Adopted Revenue						
14	Proposed Retail Revenue Requirement (Line 13)	1,819,732	1,656,202	(163,529)	1,539,847	116,355	14
15	Less: Adopted Retail Revenue (Line 1)	1,490,498	1,490,498	0	1,490,498	0	15
16	Increase in Retail Revenue Requirement over Adopted Revenue	329,234	165,704	(163,529)	49,349	116,355	16

PG&E's column (A) revenues include MRTU and Tesla.
PG&E's present revenues for New Projects (column (A), row 1) were updated subsequent to filing the Joint Comparison Exhibit.

Table 3-2

Pacific Gas and Electric Company

2011 PG&E GRC (SETTLEMENT)

Results of Operations at Proposed Rates

Electric Generation

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	1,819,732	1,656,202	(163,529)	1,539,847	116,355	1
2	Plus Other Operating Revenue	11,647	11,645	(2)	11,641	4	2
3	Total Operating Revenue	1,831,379	1,667,848	(163,531)	1,551,488	116,360	3
	OPERATING EXPENSES:						
4	Energy Costs	0	0	0	0	0	4
5	Production	574,462	534,586	(39,876)	470,680	63,906	5
6	Storage	0	0	0	0	0	6
7	Transmission	6,301	6,301	0	6,214	87	7
8	Distribution	0	0	0	0	0	8
9	Customer Accounts	0	0	0	0	0	9
10	Uncollectibles	5,215	5,169	(46)	4,099	1,070	10
11	Customer Services	0	0	0	0	0	11
12	Administrative and General	214,142	191,905	(22,236)	159,643	32,262	12
13	Franchise Requirements	13,842	12,603	(1,239)	11,729	874	13
14	Amortization	6,180	6,180	0	4,572	1,607	14
15	Wage Change Impacts	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	16
17	Other Adjustments	74	(5,082)	(5,156)	74	(5,156)	17
18	Subtotal Expenses:	820,215	751,663	(68,553)	657,012	94,651	18
	TAXES:						
19	Superfund	0	0	0	0	0	19
20	Property	48,666	48,520	(146)	47,198	1,321	20
21	Payroll	29,433	27,768	(1,665)	23,949	3,819	21
22	Business	252	252	0	251	2	22
23	Other	581	581	0	1,093	(511)	23
24	State Corporation Franchise	34,602	29,200	(5,402)	28,423	777	24
25	Federal Income	149,260	128,074	(21,186)	122,972	5,103	25
26	Total Taxes	262,796	234,397	(28,400)	223,886	10,511	26
27	Depreciation	306,348	284,889	(21,459)	285,989	(1,101)	27
28	Fossil Decommissioning	40,786	38,286	(2,500)	34,668	3,618	28
29	Nuclear Decommissioning	0	0	0	0	0	29
30	Total Operating Expenses	1,430,145	1,309,234	(120,912)	1,201,555	107,679	30
31	Net for Return	401,234	358,614	(42,620)	349,933	8,681	31
32	Rate Base	4,564,660	4,079,794	(484,867)	3,981,030	98,763	32
	RATE OF RETURN:						
33	On Rate Base	**8.79%**	**8.79%**		**8.79%**		33
34	On Equity	**11.35%**	**11.35%**		**11.35%**		34

Table 3-3

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Income Taxes at Proposed Rates
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
1	Revenues	1,831,379	1,667,848	(163,531)	1,551,488	116,360	1
2	O&M Expenses	820,215	751,663	(68,553)	657,012	94,651	2
3	Nuclear Decommissioning Expense	0	0	0	0	0	3
4	Superfund Tax	0	0	0	0	0	4
5	Taxes Other Than Income	78,933	77,122	(1,811)	72,492	4,630	5
6	Subtotal	932,230	839,063	(93,167)	821,984	17,079	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	126,898	113,418	(13,479)	110,673	2,746	7
8	Fiscal/Calendar Adjustment	6,967	6,906	(61)	6,304	602	8
9	Operating Expense Adjustments	14,925	14,936	11	16,265	(1,329)	9
10	Capitalized Interest Adjustment	0	0	0	0	0	10
11	Capitalized Inventory Adjustment	0	0	0	0	0	11
12	Vacation Accrual Reduction	(747)	(747)	0	(747)	0	12
13	Capitalized Other	1,294	1,286	(8)	828	458	13
14	Subtotal Deductions	149,336	135,799	(13,537)	133,323	2,477	14
	CCFT TAXES:						
15	State Operating Expense Adjustment	2,295	2,297	2	2,297	0	15
16	State Tax Depreciation - Declining Balance	0	0	0	0	0	16
17	State Tax Depreciation - Fixed Assets	351,371	340,858	(10,513)	325,074	15,784	17
18	State Tax Depreciation - Other	0	0	0	0	0	18
19	Removal Costs	2,749	2,297	(452)	2,300	(3)	19
20	Repair Allowance	0	0	0	0	0	20
21	Subtotal Deductions	505,751	481,251	(24,499)	462,994	18,258	21
22	Taxable Income for CCFT	426,480	357,812	(68,668)	358,990	(1,179)	22
23	CCFT	37,701	31,631	(6,070)	31,735	(104)	23
24	State Tax Adjustment	0	0	0	0	0	24
25	Current CCFT	37,701	31,631	(6,070)	31,735	(104)	25
26	Deferred Taxes - Reg Asset	1,107	1,107	0	1,107	0	26
27	Deferred Taxes - Interest	203	203	0	203	0	27
28	Deferred Taxes - Vacation	(66)	(66)	0	(66)	0	28
29	Deferred Taxes - Other	0	0	0	0	0	29
30	Deferred Taxes - Fixed Assets	(4,342)	(3,675)	668	(4,556)	882	30
31	Total CCFT	34,602	29,200	(5,402)	28,423	777	31
	FEDERAL TAXES:						
32	CCFT - Prior Year	17,580	16,640	(940)	19,441	(2,801)	32
33	Federal Operating Expense Adjustment	4,194	4,198	3	4,198	0	33
34	Fed. Tax Depreciation - Declining Balance	0	0	0	0	0	34
35	Federal Tax Depreciation - SLRL	0	0	0	0	0	35
36	Federal Tax Depreciation - Fixed Assets	330,055	310,098	(19,957)	301,420	8,678	36
37	Federal Tax Depreciation - Other	0	0	0	0	0	37
38	Removal Costs	2,749	2,297	(452)	2,300	(3)	38
39	Repair Allowance	0	0	0	0	0	39
40	Preferred Dividend Credit	2,321	2,321	(0)	2,321	0	40
41	Subtotal Deductions	506,234	471,352	(34,882)	463,002	8,350	41
42	Taxable Income for FIT	425,996	367,711	(58,285)	358,982	8,728	42
43	Federal Income Tax	149,099	128,699	(20,400)	125,644	3,055	43
44	Deferred Taxes - Reg Asset	3,996	3,996	0	3,996	0	44
45	Tax Effect of MTD & Prod Tax Credits	(13,124)	(11,647)	1,477	(10,710)	(936)	45
46	Deferred Taxes - Interest	594	595	1	595	0	46
47	Deferred Taxes - Vacation	(238)	(238)	0	(238)	0	47
48	Deferred Taxes - Other	0	0	0	0	0	48
49	Deferred Taxes - Fixed Assets	8,934	6,670	(2,264)	3,686	2,984	49
50	Total Federal Income Tax	149,260	128,074	(21,186)	122,972	5,103	50

Table 3-4

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Total Escalation
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Total Escalated						
1	Energy Cost	0	0	0	0	0	1
2	Production	574,462	534,586	(39,876)	470,680	63,906	2
3	Storage	0	0	0	0	0	3
4	Transmission	6,301	6,301	0	6,214	87	4
5	Distribution	0	0	0	0	0	5
6	Customer Accounts	0	0	0	0	0	6
7	Customer Services	0	0	0	0	0	7
8	Administrative and General	203,904	181,668	(22,236)	153,344	28,325	8
9	Other	74	(5,082)	(5,156)	74	(5,156)	9
10	Total Escalated	784,741	717,474	(67,268)	630,312	87,162	10
11	Wage Related A&G Escalated	10,237	10,237	0	6,300	3,937	11
	Total Non-Escalated						
12	Energy Cost	0	0	0	0	0	12
13	Production	531,442	493,353	(38,089)	443,721	49,632	13
14	Storage	0	0	0	0	0	14
15	Transmission	5,827	5,827	0	5,827	0	15
16	Distribution	0	0	0	0	0	16
17	Customer Accounts	0	0	0	0	0	17
18	Customer Services	0	0	0	0	0	18
19	Administrative and General	191,272	170,296	(20,976)	144,290	26,006	19
20	Other	74	(5,082)	(5,156)	74	(5,156)	20
21	Total Non-Escalated	728,614	664,394	(64,220)	593,912	70,482	21
22	Wage Related A&G Non-Escalated	9,167	9,167	0	5,641	3,526	22
	Total Escalation						
23	Energy Cost	0	0	0	0	0	23
24	Production	43,021	41,233	(1,787)	26,959	14,274	24
25	Storage	0	0	0	0	0	25
26	Transmission	474	474	0	387	87	26
27	Distribution	0	0	0	0	0	27
28	Customer Accounts	0	0	0	0	0	28
29	Customer Services	0	0	0	0	0	29
30	Administrative and General	12,633	11,372	(1,261)	9,054	2,319	30
31	Other	0	0		0	0	31
32	Total Escalation	56,128	53,080	(3,048)	36,400	16,680	32
33	Wage Related A&G Escalation	1,070	1,070	0	659	412	33
34	Acct 926 M&S - Empl Pensions & Benefits	0	0	0	0	0	34
35	Acct 924 Other - Property Insurance	3,786	3,786	0	3,763	23	35
36	Acct 926 Other - Empl Pensions & Benefits	0	0	0	0	0	36

Table 3-5

Pacific Gas and Electric Company

2011 PG&E GRC (SETTLEMENT)

Franchise and Uncollectibles at Proposed Rates
Electric Generation

$(000)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Uncollectible Accounts						
1	Rate Case Revenues	1,831,379	1,667,848	(163,531)	1,551,488	116,360	1
2	Percent of Revenue from Customers	0.998200	0.998200	0.000000	0.998200	0.000000	2
3	Rate Case Revenues from Customers	1,828,082	1,664,845	(163,237)	1,548,695	116,150	3
4	Uncollectible Rate	0.00285	0.00311	0.000252	0.00265	0.00046	4
5	Uncollectible Accounts Expense	5,215	5,169	(46)	4,099	1,070	5
	Franchise Fees						
6	Rate Case Revenues from Customers	1,828,082	1,664,845	(163,237)	1,548,695	116,150	6
7	Uncollectible Accounts Expense	5,215	5,169	(46)	4,099	1,070	7
8	Net Rate Case Revenue from Customers	1,822,867	1,659,676	(163,191)	1,544,596	115,080	8
9	Franchise Rate	0.00759	0.00759	0.00000	0.00759	0.00000	9
10	Franchise Fees Expense	13,842	12,603	(1,239)	11,729	874	10

Table 3-6

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Payroll and Other Taxes
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Property (Ad Valorem) Tax:						
1	Fiscal Year Tax	55,633	55,426	(207)	53,502	1,924	1
2	Calendar Year Tax	48,666	48,520	(146)	47,198	1,321	2
	Payroll Taxes						
3	Federal Insurance Contribution Act (FICA)	24,634	23,504	(1,130)	20,303	3,201	3
4	Federal Unemployment Insurance (FUI)	241	230	(11)	198	31	4
5	State Unemployment Insurance (SUI)	1,324	1,263	(61)	1,091	172	5
6	San Francisco Employee Tax	3,235	2,771	(464)	2,357	414	6
7	Total Payroll Taxes	29,433	27,768	(1,665)	23,949	3,819	7
	Other Taxes						
8	Business	252	252	0	251	2	8
9	Hazardous Waste	0	0	0	0	0	9
10	Windfall Profits	0	0	0	0	0	10
11	Other	581	581	0	1,093	(511)	11
12	Total Other Taxes	834	834	0	1,344	(510)	12
13	Total Taxes Other Than Income	78,933	77,122	(1,811)	72,492	4,630	13

Table 3-7

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Plant In Service - Test Year 2011
Electric Generation
(Thousands of Dollars)

		Annual Plant in Service					Weighted Average Plant in Service					
Line No.	Description	PG&E Position (A)	SETTLEMENT Position (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	PG&E Position (F)	SETTLEMENT Position (G)	Difference SETTLEMENT v PG&E (H) = (G)-(F)	DRA 2011 (I)	Difference SETTLEMENT v DRA (J)=(G)-(I)	Line No.
	Year 2008											
1	Total End-of-Year Plant	10,253,451	10,251,206	(2,245)	10,251,206	0	10,151,923	10,149,722	(2,202)	10,149,722	0	1
	Year 2009											
2	Total Full-Year Net Additions	725,963	676,193	(49,770)	614,130	62,063	484,757	457,965	(26,792)	416,613	41,352	2
3	Total End-of-Year Plant	10,979,414	10,927,399	(52,015)	10,865,336	62,063	10,738,208	10,709,171	(29,037)	10,678,379	30,792	3
	Year 2010											
4	Total Full-Year Net Additions	1,193,551	1,182,959	(10,592)	1,078,748	104,211	250,886	250,399	(486)	222,422	27,977	4
5	Total End-of-Year Plant	12,172,966	12,110,358	(62,608)	11,944,085	166,274	11,230,300	11,177,798	(52,502)	11,102,960	74,838	5
	Year 2011											
6	Total Full-Year Net Additions	306,009	250,144	(55,865)	256,751	(6,608)	68,249	35,813	(32,436)	54,263	(18,450)	6
7	Total End-of-Year Plant	12,478,975	12,360,502	(118,473)	12,200,836	159,666	12,241,215	12,146,171	(95,044)	12,013,582	132,589	7

Table 3-8

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Depreciation
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Depreciation						
1	Annual	306,348	284,889	(21,459)	285,989	(1,101)	1
2	Reserve	7,794,515	7,769,399	(25,116)	7,775,284	(5,885)	2
3	Weighted Average Reserve	7,693,461	7,675,264	(18,197)	7,676,271	(1,007)	3

Table 3-9

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)

Working Cash Capital
Electric Generation

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	Operational Cash Requirements:						
1	Required Bank Balances	0	0	0	0	0	1
2	Special Deposits and Working Funds	35	35	(0)	34	1	2
3	Other Receivables	20,152	20,138	(14)	19,614	524	3
4	Prepayments	11,183	11,183	0	11,422	(239)	4
5	Deferred Debits, Company-Wide	(34)	(34)	0	(33)	(2)	5
	Less:						
6	Working Cash Capital not Supplied by Investors	2,689	2,689	0	2,887	(198)	6
7	Goods Delivered to Construction Sites	3,211	3,211	0	3,192	19	7
8	Accrued Vacation	44,631	42,585	(2,046)	36,785	5,800	8
	Add:						
9	Prepayment, Departmental	(4,934)	(4,934)	0	4,373	(9,307)	9
10	Total Operational Cash Requirement	(24,129)	(22,097)	2,032	(7,453)	(14,645)	10
11	Plus Working Cash Capital Requirement Resulting from the Lag in Collection of Revenues being greater than the Lag in the Payment of Expenses	34,714	38,307	3,593	32,265	6,043	11
12	Working Cash Capital Supplied by Investors	10,585	16,210	5,625	24,812	(8,602)	12

Table 3-10

Pacific Gas and Electric Company
2011 PG&E GRC (SETTLEMENT)
Ratebase
Electric Generation
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	SETTLEMENT 2011 (B)	Difference SETTLEMENT v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference SETTLEMENT v DRA (E)=(B)-(D)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	12,172,966	12,110,358	(62,608)	11,959,319	151,039	1
2	Net Additions	68,249	35,813	(32,436)	54,263	(18,450)	4
3	Total Weighted Average Plant	12,241,215	12,146,171	(95,044)	12,013,582	132,589	5
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	379,680	0	(379,680)	0	0	6
5	Material and Supplies - Other	91,672	91,672	0	81,273	10,399	7
6	Working Cash	10,585	16,210	5,625	24,812	(8,602)	8
7	Total Working Capital	481,938	107,883	(374,055)	106,085	1,797	9
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	3,374	3,376	1	3,376	0	10
9	Deferred Vacation	9,082	9,080	(3)	9,080	0	11
10	Deferred CIAC Tax Effects	0	0	0	0	0	12
11	Total Adjustments	12,456	12,455	(1)	12,455	0	13
12	CUSTOMER ADVANCES	0	0	0	0	0	14
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	(36,427)	(36,427)	0	(36,427)	0	15
14	Accumulated Fixed Assets	504,235	538,209	33,974	501,579	36,630	16
15	Accumulated Other	0	0	0	0	0	17
16	Deferred ITC	9,680	9,670	(10)	9,670	0	18
17	Deferred Tax - Other	0	0	0	0	0	19
18	Total Deferred Taxes	477,487	511,451	33,964	474,822	36,630	20
19	DEPRECIATION RESERVE	7,693,461	7,675,264	(18,197)	7,676,271	(1,007)	21
20	TOTAL Ratebase	4,564,660	4,079,794	(484,867)	3,981,030	98,763	22

Table 3-11

PG&E

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

PG&E Final Position - Electric Department

Line No.	Description	Component (A)	Post Deduction Revenue (B)	Cumulative Components (C)	Net-To Gross Multiplier (D)	Line No.
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.002853	0.997152	0.002848	1.002856	2
3	Franchise Requirements	0.007593	0.989594	0.007558	1.010515	3
4	Super Fund Tax	0.000000	0.989594	0.000000	1.010515	4
5	State Income Tax	0.088400	0.902114	0.087480	1.108507	5
6	Federal Income Tax	0.350000	0.555756	0.346358	1.799351	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 3-12

SETTLEMENT

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

SETTLEMENT - Electric Department

Line No.	Description	Component (A)	Post Deduction Revenue (B)	Cumulative Components (C)	Net-To Gross Multiplier (D)	Line No.
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.003105	0.996901	0.003099	1.003109	2
3	Franchise Requirements	0.007593	0.989344	0.007556	1.010770	3
4	Super Fund Tax	0.000000	0.989344	0.000000	1.010770	4
5	State Income Tax	0.088400	0.901886	0.087458	1.108787	5
6	Federal Income Tax	0.350000	0.555616	0.346271	1.799805	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

Table 3-13

DRA

2011 PG&E GRC (SETTLEMENT)

Development of the Net-To-Gross Multiplier

Test Year 2011

DRA Final Position - Electric Department

Line No.	Description	Component	Post Deduction Revenue	Cumulative Components	Net-To Gross Multiplier	Line No.
		(A)	(B)	(C)	(D)	
	Including F&U					
1	Gross Operating Revenue		1.000000	0.998200		1
	Less:					
2	Uncollectible Accounts	0.002647	0.997358	0.002642	1.002649	2
3	Franchise Requirements	0.007593	0.989798	0.007560	1.010307	3
4	Super Fund Tax	0.000000	0.989798	0.000000	1.010307	4
5	State Income Tax	0.088400	0.902300	0.087498	1.108279	5
6	Federal Income Tax	0.350000	0.555871	0.346429	1.798980	6
	Excluding F&U					
7	Gross Operating Revenue		1.000000	1.000000		7
	Less:					
8	Uncollectible Accounts	0.000000	1.000000	0.000000	1.000000	8
9	Franchise Requirements	0.000000	1.000000	0.000000	1.000000	9
10	Super Fund Tax	0.000000	1.000000	0.000000	1.000000	10
11	State Income Tax	0.088400	0.911600	0.088400	1.096972	11
12	Federal Income Tax	0.350000	0.561600	0.350000	1.780627	12

CERTIFICATE OF SERVICE

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, Law Department B30A, 77 Beale Street, San Francisco, California 94105.

On **October 15, 2010**, I served a true copy of:

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY; DIVISION OF RATEPAYER ADVOCATES; THE UTILITY REFORM NETWORK; AGLET CONSUMER ALLIANCE; CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION; CALIFORNIA FARM BUREAU FEDERATION; COALITION OF CALIFORNIA UTILITY EMPLOYEES; CONSUMER FEDERATION OF CALIFORNIA; DIRECT ACCESS CUSTOMER COALITION; DISABILITY RIGHTS ADVOCATES; ENERGY PRODUCERS AND USERS COALITION; ENGINEERS AND SCIENTISTS OF CALIFORNIA, LOCAL 20; MERCED IRRIGATION DISTRICT; MODESTO IRRIGATION DISTRICT; SOUTH SAN JOAQUIN IRRIGATION DISTRICT; WESTERN POWER TRADING FORUM; AND WOMEN'S ENERGY MATTERS FOR ADOPTION OF SETTLEMENT AGREEMENT

by electronic mail, or (for those parties without valid electronic mail addresses) by placing it for collection and mailing, in the course of ordinary business practice, with other correspondence of Pacific Gas and Electric Company, enclosed in a sealed envelope, with postage fully prepaid, addressed to:

All parties on the attached Service Lists.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on **October 15, 2010**.

/s/

Rene Anita Thomas

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
EMAIL SERVICE LIST

Last Updated: October 8, 2010

CPUC DOCKET NO. A0912020

a2mx@pge.com;akhan@visiumfunds.com;anders@opentopensightseeing.com;ASteinberg@SempraUtilities.com;atrowbridge@daycartermurphy.com;bcragg@goodinmacbride.com;beg@cpuc.ca.gov;BermanEconomics@gmail.com;bfinkelstein@turn.org;bkc7@pge.com;blaising@braunlegal.com;bpf2@pge.com;brbarkovich@earthlink.net;case.admin@sce.com;cem@newsdata.com;CentralFiles@SempraUtilities.com;ckt@cpuc.ca.gov;cmkehrein@ems-ca.com;dao@cpuc.ca.gov;dbp@cpuc.ca.gov;dbyers@landuselaw.com;dfb@cpuc.ca.gov;dfdavy@well.com;dgeis@dolphingroup.org;dietrichlaw2@earthlink.net;dkf@cpuc.ca.gov;dlf@cpuc.ca.gov;dmarcus2@sbcglobal.net;douglass@energyattorney.com;edwardoneill@dwt.com;enriqueg@greenlining.org;epoole@adplaw.com;filings@a-klaw.com;francis.mcnulty@sce.com;fsmith@sfwater.org;garrick@jbsenergy.com;hayley@turn.org;HEmmrich@SempraUtilities.com;IErgovic@Jefferies.com;info@dcisc.org;janreid@coastecon.com;jheckler@levincap.com;jimross@r-c-s-inc.com;joyw@mid.org;judypau@dwt.com;julien.dumoulin-smith@ubs.com;jweil@aglet.org;K1Ch@pge.com;kerntax@kerntaxpayers.org;kjsimonsen@ems-ca.com;kkm@cpuc.ca.gov;KMelville@SempraUtilities.com;kmills@cfbf.com;kris.vyas@sce.com;lauren.duke@db.com;lawcpuccases@pge.com;lex@consumercal.org;ljt@cpuc.ca.gov;lmh@eslawfirm.com;martinhomec@gmail.com;mdjoseph@adamsbroadwell.com;mmattes@nossaman.com;mramirez@sfwater.org;mrw@mrwassoc.com;nes@a-klaw.com;nms@cpuc.ca.gov;pgg4@pge.com;pk@utilitycostmanagement.com;pucservice@dralegal.org;pucservice@dralegal.org;ram@cpuc.ca.gov;regclfp@gmail.com;RegRelCPUCCases@pge.com;rkoss@adamsbroadwell.com;rmccann@umich.edu;rmp@cpuc.ca.gov;rnevis@daycartermurphy.com;rschmidt@bartlewells.com;salleyoo@dwt.com;samuelk@greenlining.org;scott.senchak@decade-llc.com;sean.beatty@mirant.com;SGM@cpuc.ca.gov;stephaniec@greenlining.org;steven@iepa.com;sue.mara@rtoadvisors.com;thomas.long@sfgov.org;txb@cpuc.ca.gov;vidhyaprabhakaran@dwt.com;wem@igc.org;wendy@econinsights.com;will.mitchell@cpv.com;william.sanders@sfgov.org;wtaylor@hansonbrigett.com;Yim@ZimmerLucas.com;zango@zimmerlucas.com;

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA SERVICE LIST

Last Updated: October 8, 2010

CPUC DOCKET NO. A0912020 - I1007027

Total number of addressees: 97

PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST, B30A
SAN FRANCISCO CA 94105-1814
Email: lawcpuccases@pge.com
Status: INFORMATION

CASE ADMINISTRATION
PACIFIC GAS & ELECTRIC COMPANY
77 BEALE ST, MC B9A
SAN FRANCISCO CA 94177
Email: RegRelCPUCCases@pge.com
Status: INFORMATION

KATHY CHAN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST, RM 996
SAN FRANCISCO CA 94177
Email: K1Ch@pge.com
Status: INFORMATION

BRUCE P. FRASER
PACIFIC GAS & ELECTRIC COMPANY
77 BEALE ST, B9A
SAN FRANCISCO CA 94105
Email: bpf2@pge.com
Status: INFORMATION

ALICIA MCMAHON GOV/PLANNING REGUL. CASE COORDINATOR
PACIFIC GAS AND ELECTRIC
77 BEALE ST RM. 996, MAIL CODE B9A
SAN FRANCISCO CA 94105
Email: a2mx@pge.com
Status: INFORMATION

BRIAN K. CHERRY DIRECTOR, REGULATORY RELATIONS
PACIFIC GAS AND ELECTRIC COMPANY (39)
77N BEALE ST., PO BOX 770000, MC B10C
SAN FRANCISCO CA 94177
FOR: Pacific Gas and Electric Company
Email: bkc7@pge.com
Status: PARTY

PATRICK G. GOLDEN ATTORNEY
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST, MAIL CODE B30A
SAN FRANCISCO CA 94105
FOR: Pacific gas & Electric Company
Email: pgg4@pge.com
Status: PARTY

Donna-Fay Bower
CALIF PUBLIC UTILITIES COMMISSION
ENERGY COST OF SERVICE & NATURAL GAS BRANCH
505 VAN NESS AVE RM 4205
SAN FRANCISCO CA 94102-3214
Email: dfb@cpuc.ca.gov
Status: STATE-SERVICE

Truman L. Burns
CALIF PUBLIC UTILITIES COMMISSION
ENERGY COST OF SERVICE & NATURAL GAS BRANCH
505 VAN NESS AVE RM 4205
SAN FRANCISCO CA 94102-3214
Email: txb@cpuc.ca.gov
Status: STATE-SERVICE

David K. Fukutome
CALIF PUBLIC UTILITIES COMMISSION
DIVISION OF ADMINISTRATIVE LAW JUDGES
505 VAN NESS AVE RM 5042
SAN FRANCISCO CA 94102-3214
Email: dkf@cpuc.ca.gov
Status: STATE-SERVICE

Belinda Gatti
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
505 VAN NESS AVE AREA 4-A
SAN FRANCISCO CA 94102-3214
Email: beg@cpuc.ca.gov
Status: STATE-SERVICE

Donald J. Lafrenz
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
505 VAN NESS AVE AREA 4-A
SAN FRANCISCO CA 94102-3214
Email: dlf@cpuc.ca.gov
Status: STATE-SERVICE

Karl Meeusen
CALIF PUBLIC UTILITIES COMMISSION
EXECUTIVE DIVISION
505 VAN NESS AVE RM 5217
SAN FRANCISCO CA 94102-3214
Email: kkm@cpuc.ca.gov
Status: STATE-SERVICE

SCOTT MURTISHAW
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL ONLY
EMAIL ONLY CA 0
Email: SGM@cpuc.ca.gov
Status: STATE-SERVICE

Richard A. Myers
CALIF PUBLIC UTILITIES COMMISSION
ENERGY DIVISION
505 VAN NESS AVE AREA 4-A
SAN FRANCISCO CA 94102-3214
Email: ram@cpuc.ca.gov
Status: STATE-SERVICE

Dao A. Phan
CALIF PUBLIC UTILITIES COMMISSION
ENERGY COST OF SERVICE & NATURAL GAS BRANCH
505 VAN NESS AVE RM 4205
SAN FRANCISCO CA 94102-3214
Email: dao@cpuc.ca.gov
Status: STATE-SERVICE

Nicholas Sher
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
505 VAN NESS AVE RM 4007
SAN FRANCISCO CA 94102-3214
Email: nms@cpuc.ca.gov
Status: STATE-SERVICE

JAMES WEIL DIRECTOR
AGLET CONSUMER ALLIANCE
PO BOX 1916
SEBASTOPOL CA 95473
FOR: Aglet Consumer Alliance
Email: jweil@aglet.org
Status: PARTY

KAREN TERRANOVA
ALCANTAR & KAHL, LLP
33 NEW MONTGOMERY ST, STE 1850
SAN FRANCISCO CA 94105
Email: filings@a-klaw.com
Status: INFORMATION

RICHARD MCCANN
ASPEN ENVIRONMENTAL GROUP
8801 FOLSOM BLVD, STE 290
SACRAMENTO CA 95826-3250
Email: rmccann@umich.edu
Status: INFORMATION

REED V. SCHMIDT
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVE
BERKELEY CA 94703-2714
Email: rschmidt@bartlewells.com
Status: INFORMATION

David Peck
CALIF PUBLIC UTILITIES COMMISSION
ELECTRICITY PLANNING & POLICY BRANCH
505 VAN NESS AVE RM 4103
SAN FRANCISCO CA 94102-3214
Email: dbp@cpuc.ca.gov
Status: STATE-SERVICE

Robert M. Pocta
CALIF PUBLIC UTILITIES COMMISSION
ENERGY COST OF SERVICE & NATURAL GAS BRANCH
505 VAN NESS AVE RM 4205
SAN FRANCISCO CA 94102-3214
Email: rmp@cpuc.ca.gov
Status: STATE-SERVICE

Clayton K. Tang
CALIF PUBLIC UTILITIES COMMISSION
ENERGY COST OF SERVICE & NATURAL GAS BRANCH
505 VAN NESS AVE RM 4205
SAN FRANCISCO CA 94102-3214
Email: ckt@cpuc.ca.gov
Status: STATE-SERVICE

DAN GEIS
AGRICULTURAL ENERGY CONSUMERS ASSN.
925 L ST, STE 800
SACRAMENTO CA 95814
FOR: Agricultural Energy Consumers Association
Email: dgeis@dolphingroup.org
Status: PARTY

EDWARD G. POOLE
ANDERSON & POOLE
601 CALIFORNIA ST, STE 1300
SAN FRANCISCO CA 94108-2812
Email: epoole@adplaw.com
Status: INFORMATION

BARBARA R. BARKOVICH
BARKOVICH & YAP, INC.
44810 ROSEWOOD TERRACE
MENDOCINO CA 95460
Email: brbarkovich@earthlink.net
Status: INFORMATION

ROBERT BERMAN
BERMAN ECONOMICS
1915 GRAND COURT
VIENNA VA 22182
Email: BermanEconomics@gmail.com
Status: INFORMATION

SCOTT BLAISING
BRAUN BLAISING MCLAUGHLIN, P.C.
915 L ST, STE 1270
SACRAMENTO CA 95814
Email: blaising@braunlegal.com
Status: INFORMATION

DAVID J. BYERS, ESQ. ATTORNEY
MCCRACKEN, BYERS & HAESLOOP, LLP
870 MITTEN ROAD
BURLINGAME CA 94010
FOR: California City-County Street Light Association
Email: dbyers@landuselaw.com
Status: PARTY

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST. STE 303
SAN FRANCISCO CA 94117-2242
Email: cem@newsdata.com
Status: INFORMATION

KAREN NORENE MILLS ATTORNEY
CALIFORNIA FARM BUREAU FEDERATION
EMAIL ONLY
EMAIL ONLY CA 0
FOR: California Farm Bureau Federation
Email: kmills@cfbf.com
Status: PARTY

JOHN LARREA
CALIFORNIA LEAGUE OF FOOD PROCESSORS
1755 CREEKSIDE OAKS DRIVE, STE 250
SACRAMENTO CA 95833
Email: regclfp@gmail.com
Status: INFORMATION

WILLIAM K. SANDERS DEPUTY CITY ATTORNEY
OFFICE OF THE CITY ATTORNEY
1 DR. CARLTON B. GOODLETT PLACE,RM 234
SAN FRANCISCO CA 94102-4682
FOR: City and County of San Francisco
Email: william.sanders@sfgov.org
Status: PARTY

RACHAEL E. KOSS
ADAMS BROADWELL JOSEPH & CARDOZA
601 GATEWAY BLVD, STE 1000
SOUTH SAN FRANCISCO CA 94080
FOR: Coalition of California Utility Employee
Email: rkoss@adamsbroadwell.com
Status: PARTY

MARC D. JOSEPH
ADAMS BROADWELL JOSEPH & CARDOZO
601 GATEWAY BLVD. STE 1000
SOUTH SAN FRANCISCO CA 94080
FOR: Coalition of California Utility Employees
Email: mdjoseph@adamsbroadwell.com
Status: INFORMATION

JAN REID
COAST ECONOMICS CONSULTING
3185 GROSS ROAD
SANTA CRUZ CA 95062
Email: janreid@coastecon.com
Status: INFORMATION

WILLIAM MITCHELL
COMPETITIVE POWER VENTURES, INC.
55 2ND ST, STE 525
SAN FRANCISCO CA 94105
Email: will.mitchell@cpv.com
Status: INFORMATION

ALEXIS K. WODTKE STAFF ATTORNEY
CONSUMER FEDERATION OF CALIFORNIA
520 S. EL CAMINO REAL, STE. 340
SAN MATEO CA 94402
FOR: Consumer Federation of California
Email: lex@consumercal.org
Status: PARTY

VIDHYA PRABHAKARAN
DAVIS WRIGHT & TREMAINE LLP
505 MONTGOMERY ST, STE 800
SAN FRANCISCO CA 94111
Email: vidhyaprabhakaran@dwt.com
Status: INFORMATION

JUDY PAU
DAVIS WRIGHT TREMAINE LLP
EMAIL ONLY
EMAIL ONLY CA 00000-0000
Email: judypau@dwt.com
Status: INFORMATION

SALLE E. YOO
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY ST, STE 800
SAN FRANCISCO CA 94111
Email: salleyoo@dwt.com
Status: INFORMATION

RALPH R. NEVIS
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., STE 205
SACRAMENTO CA 95864
Email: rnevis@daycartermurphy.com
Status: INFORMATION

SCOTT SENCHAK
DECADE CAPITAL
EMAIL ONLY
EMAIL ONLY CA 00000-0000
Email: scott.senchak@decade-llc.com
Status: INFORMATION

LAUREN DUKE
DEUTSCHE BANK SECURITIES INC.
60 WALL ST
NEW YORK NY 10005
Email: lauren.duke@db.com
Status: INFORMATION

WILLIAM F. DIETRICH ATTORNEY
DIETRICH LAW
2977 YGNACIO VALLEY ROAD, NO. 613
WALNUT CREEK CA 94598-3535
Email: dietrichlaw2@earthlink.net
Status: INFORMATION

KARLA GILBRIDE
DISABILITY RIGHTS ADVOCATES
2001 CENTER ST, 4TH FLR
BERKELEY CA 94704-1204
Email: pucservice@dralegal.org
Status: INFORMATION

MELISSA A. KASNITZ ATTORNEY
DISABILITY RIGHTS ADVOCATES
2001 CENTER ST, FOURTH FLR
BERKELEY CA 94704-1204
FOR: Disability Rights Advocates
Email: pucservice@dralegal.org
Status: PARTY

Laura J. Tudisco
CALIF PUBLIC UTILITIES COMMISSION
LEGAL DIVISION
505 VAN NESS AVE RM 5032
SAN FRANCISCO CA 94102-3214
FOR: Division of Ratepayers Advocate
Email: ljt@cpuc.ca.gov
Status: PARTY

WENDY L. ILLINGWORTH
ECONOMIC INSIGHTS
320 FEATHER LANE
SANTA CRUZ CA 95060
Email: wendy@econinsights.com
Status: INFORMATION

LYNN HAUG
ELLISON, SCHNEIDER & HARRIS L.L.P.
2600 CAPITAL AVE, STE 400
SACRAMENTO CA 95816
Email: lmh@eslawfirm.com
Status: INFORMATION

CAROLYN KEHREIN
ENERGY MANAGEMENT SERVICES
2602 CELEBRATION WAY
WOODLAND CA 95776
Email: cmkehrein@ems-ca.com
Status: INFORMATION

KEVIN J. SIMONSEN
ENERGY MANAGEMENT SERVICES
646 E. THIRD AVE.
DURANGO CA 81301
FOR: Energy Management Services
Email: kjsimonsen@ems-ca.com
Status: PARTY

NORA SHERIFF
ALCANTAR & KAHL
33 NEW MONTGOMERY ST, STE 1850
SAN FRANCISCO CA 94105
FOR: Energy Producers & Users Coalition
Email: nes@a-klaw.com
Status: PARTY

BRIAN T. CRAGG
GOODIN MACBRIDE SQUERI, DAY & LAMPREY
505 SANSOME ST, STE 900
SAN FRANCISCO CA 94111
FOR: Engineers and Scientists of California Local 70
Email: bcragg@goodinmacbride.com
Status: PARTY

DONN DAVY
EMAIL ONLY
EMAIL ONLY CA 0
Email: dfdavy@well.com
Status: INFORMATION

DAVID MARCUS
PO BOX 1287
BERKELEY CA 94701
Email: dmarcus2@sbcglobal.net
Status: INFORMATION

GARRICK JONES
JBS ENERGY
311 D ST
WEST SACRAMENTO CA 95605
Email: garrick@jbsenergy.com
Status: INFORMATION

MICHAEL TURNIPSEED EXEC. DIR.
KERN COUNTY TAXPAYERS ASSOCIATION
331 TRUTUN AVE
BAKERSFIELD CA 93301
FOR: Kern County Taxpayers Association
Email: kerntax@kerntaxpayers.org
Status: INFORMATION

ANN L. TROWBRIDGE
DAY CARTER MURPHY LLC
3620 AMERICAN RIVER DRIVE, STE 205
SACRAMENTO CA 95864
FOR: Merced Irrigation District/Modesto Irrigation District
Email: atrowbridge@daycartermurphy.com
Status: PARTY

JOY A. WARREN
MODESTO IRRIGATION DISTRICT
1231 11TH ST
MODESTO CA 95354
Email: joyw@mid.org
Status: INFORMATION

MARTIN A. MATTES ATTY AT LAW
NOSSAMAN LLP
50 CALIFORNIA ST, 34TH FLR
SAN FRANCISCO CA 94111-4799
Email: mmattes@nossaman.com
Status: INFORMATION

WILLIAM D. TAYLOR
HANSON BRIDGETT LLP
500 CAPITAL MALL, STE 1500
SACRAMENTO CA 95814
FOR: Open Top Sightseeing San Francisco, LLC
Email: wtaylor@hansonbrigett.com
Status: PARTY

STEVEN KELLY POLICY DRECTOR
INDEPENDENT ENERGY PRODUCERS ASSOCIATION
1215 K ST, STE 900
SACRAMENTO CA 95814
FOR: Independent Energy Producers Association
Email: steven@iepa.com
Status: PARTY

IVANA ERGOVIC
JEFFERIES & COMPANY, INC.
520 MADISON AVE, 19TH FLR
NEW YORK NY 10022
Email: IErgovic@Jefferies.com
Status: INFORMATION

JAMES J. HECKLER
LEVIN CAPITAL STRATEGIES
595 MADISON AVE
NEW YORK NY 10022
Email: jheckler@levincap.com
Status: INFORMATION

SEAN P. BEATTY
MIRANT CALIFORNIA, LLC
PO BOX 192
PITTSBURGH CA 94565
Email: sean.beatty@mirant.com
Status: INFORMATION

MRW & ASSOCIATES, LLC
EMAIL ONLY
EMAIL ONLY CA 0
Email: mrw@mrwassoc.com
Status: INFORMATION

THOMAS J. LONG
OFFICE OF THE CITY ATTORNEY
CITY HALL, RM 234
SAN FRANCISCO CA 94102
Email: thomas.long@sfgov.org
Status: INFORMATION

ANDERS NIELSEN
OPEN TOP SIGHTSEEING SAN FRANCISCO, LLC
5500 TUXEDO ROAD
HYATTSVILLE MD 20781
Email: anders@opentopensightseeing.com
Status: INFORMATION

JIM ROSS
RCS, INC.
500 CHESTERFIELD CENTER, STE 320
CHESTERFIELD MO 63017
Email: jimross@r-c-s-inc.com
Status: INFORMATION

SUE MARA
RTO ADVISORS, LLC
164 SPRINGDALE WAY
REDWOOD CITY CA 94062
Email: sue.mara@rtoadvisors.com
Status: INFORMATION

KEITH MELVILLE
SAN DIEGO GAS & ELECTRIC COMPANY
101 ASH ST, HQ 13D
SAN DIEGO CA 92101
FOR: San Diego Gas & Electric/Southern California Gas Company
Email: KMelville@SempraUtilities.com
Status: PARTY

CENTRAL FILES (CP31E)
SAN DIEGO GAS AND ELECTRIC CO.
8330 CENTURY PARK COURT
SAN DIEGO CA 92123
Email: CentralFiles@SempraUtilities.com
Status: INFORMATION

MANUEL RAMIREZ
SAN FRANCISCO PUC - POWER ENTERPRISE
1155 MARKET ST, 4TH FLR
SAN FRANCISCO CA 94103
Email: mramirez@sfwater.org
Status: INFORMATION

FRASER D. SMITH CITY AND COUNTY OF SAN FRANCISCO
SAN FRANCISCO PUBLIC UTILITIES COMM
1155 MARKET ST, 4TH FLR
SAN FRANCISCO CA 94103
Email: fsmith@sfwater.org
Status: INFORMATION

EDWARD W. O'NEILL
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY ST, STE 800
SAN FRANCISCO CA 94111-6533
FOR: South San Joaquin Irrigation District
Email: edwardoneill@dwt.com
Status: PARTY

CASE ADMINISTRATION
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE, RM 370
ROSEMEAD CA 91770
Email: case.admin@sce.com
Status: INFORMATION

HERB EMMRICH SAN DEIGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS CO., GT14D6
555 WEST 5TH ST
LOS ANGELES CA 90013
Email: HEmmrich@SempraUtilities.com
Status: INFORMATION

ANDREW STEINBERG
SOUTHERN CALIFORNIA GAS CO.
555 W. 5TH ST, GT 14D6
LOS ANGELES CA 90013-1034
Email: ASteinberg@SempraUtilities.com
Status: INFORMATION

KRIS G. VYAS
SOUTHERN CALIFORNIA EDISON COMPANY
QUAD 3-B
2244 WALNUT GROVE AVE
ROSEMEAD CA 91770
Email: kris.vyas@sce.com
Status: INFORMATION

SCOTT WILDER
SOUTHERN CALIFORNIA GAS CO., GT14D6
555 W. 5TH ST
LOS ANGELES CA 90013-1034
Status: INFORMATION

FRANCIS MCNULTY ATTORNEY
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE
ROSEMEAD CA 91770
FOR: Southern California Edison
Email: francis.mcnulty@sce.com
Status: PARTY

STEPHANIE C. CHEN
THE GREENLINING INSTITUTE
EMAIL ONLY
EMAIL ONLY CA 0
FOR: The Greenlining Institute
Email: stephaniec@greenlining.org
Status: PARTY

ENRIQUE GALLARDO
THE GREENLINING INSTITUTE
1918 UNIVERSITY AVE., 2ND FLR
BERKELEY CA 94704-1051
Email: enriqueg@greenlining.org
Status: INFORMATION

SAMUEL S. KANG
THE GREENLINING INSTITUTE
1918 UNIVERSITY AVE, 2ND FLR.
BERKELEY CA 94704
Email: samuelk@greenlining.org
Status: INFORMATION

ROBERT FINKELSTEIN
THE UTILITY REFORM NETWORK
115 SANSOME ST, STE 900
SAN FRANCISCO CA 94104
Email: bfinkelstein@turn.org
Status: INFORMATION

HAYLEY GOODSON
THE UTILITY REFORM NETWORK
115 SANSOME ST, STE 900
SAN FRANCISCO CA 94104
FOR: The Utility Reform Network
Email: hayley@turn.org
Status: PARTY

JULIEN DUMOULIN-SMITH ASSOCIATE ANALYST
UBS INVESTMENT RESEARCH
1285 AVE OF THE AMERICAS
NEW YORK NY 10019
Email: julien.dumoulin-smith@ubs.com
Status: INFORMATION

PAUL KERKORIAN
UTILITY COST MANAGEMENT LLC
6475 N. PALM AVE, STE 105
FRESNO CA 93704
Email: pk@utilitycostmanagement.com
Status: INFORMATION

ASHAR KHAN
VISIUM ASSET MANAGEMENT
EMAIL ONLY
EMAIL ONLY NY 0
Email: akhan@visiumfunds.com
Status: INFORMATION

ROBERT RATHIE
WELLINGTON LAW OFFICE
857 CASS ST, STE D
MONTEREY CA 93940
Email: info@dcisc.org
Status: INFORMATION

DANIEL DOUGLASS ATTORNEY
DOUGLASS & LIDDELL
21700 OXNARD ST, STE 1030
WOODLAND HILLS CA 91367
FOR: Western Power Trading Forum/Alliance for Retail Energy Markets/Equinix, Inc./Direct Access Customer Coalition
Email: douglass@energyattorney.com
Status: PARTY

MARTIN HOMEC
EMAIL ONLY
EMAIL ONLY CA 00000-0000
FOR: Women's Energy Matters
Email: martinhomec@gmail.com
Status: INFORMATION

BARBARA GEORGE
WOMEN'S ENERGY MATTERS
PO BOX 548
FAIRFAX CA 94978-0548
FOR: Womern's Energy Matters
Email: wem@igc.org
Status: PARTY

ANDREW YIM
ZIMMER LUCAS PARTNERS
535 MADISON AVE., 6TH FLR
NEW YORK NY 10022
Email: Yim@ZimmerLucas.com
Status: INFORMATION

ADAR ZANGO ANALYST
ZIMMER LUCAS PARTNERS
535 MADISON - 6TH FLR
NEW YORK NY 10022
Email: zango@zimmerlucas.com
Status: INFORMATION