Date of Issuance 5/13/2011

Decision 11-05-018 May 5, 2011

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. (U39M)	Application 09-12-020 (Filed December 21, 2009)
Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Service and Facilities of Pacific Gas and Electric Company.	Investigation 10-07-027 (Filed July 29, 2010)

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY TEST YEAR 2011 GENERAL RATE INCREASE REQUEST

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DECISION ON PACIFIC GAS AND ELECTRIC COMPANY TEST YEAR 2011 GENERAL RATE INCREASE REQUEST

1. Summary of Decision

A settlement agreement that resolves all but one issue in Pacific Gas and Electric Company's test year 2011 general rate case (GRC) is adopted with modifications and clarification. Modifications involve reporting related to cost reprioritizations and deferrals and gas distribution pipeline safety reporting. With respect to the lone remaining issue that relates to the ratemaking treatment for the undepreciated plant balance associated with electric meters that are replaced by SmartMeters, that plant balance will be amortized over a six-year period with the associated rate of return on the unamortized balance reduced to 6.3% to reflect the reduced regulatory risk for that plant.

Pacific Gas and Electric Company is authorized a GRC revenue requirement increase for 2011 amounting to $450 million, or 8.1%, over the current authorized level of $5,582 million. The authorized increase is comprised of $237 million for electric distribution, $47 million for gas distribution, and $166 million for electric generation. The decision also authorizes additional post-test year attrition increases totaling $180 million for 2012 and $185 million for 2013.

2. PG&E's Request

On December 21, 2009, Pacific Gas and Electric Company (PG&E) filed Application (A.) 09-12-020 requesting a test year 2011 general rate case (GRC) revenue requirement increase of $1,048 million (18.6%) over the then current authorized GRC level of $5,641 million. The requested increase is comprised of $525 million for electric distribution, $213 million for gas distribution, and $310 million for electric generation. Based on its proposed methodology for calculation of post-test year attrition year revenue requirements, PG&E estimated further revenue requirement increases totaling $276 million for attrition year 2012 and $344 million for attrition year 2013.

The electric distribution revenue requirement request is based on the costs PG&E forecasts it will incur in 2011 to: (1) own, operate and maintain (a) its distribution plant; (b) a portion of its transmission plant providing service directly to specific customers and connecting to specific generation resources; and (c) a portion of its common and general plant; as well as (2) provide services to its electric customers.

The gas distribution revenue requirement request is based on the costs PG&E forecasts it will incur in 2011 to: (1) own, operate, and maintain its distribution plant and a portion of common and general plant; (2) perform the transactions necessary to acquire gas supplies for core gas customers; and (3) provide services to its gas customers.

The generation revenue requirement request is based on the costs PG&E forecasts it will incur in 2011 to: (1) own, operate and maintain its electric generating plant; and (2) perform the transactions necessary to procure electricity for its bundled-service electric customers.

PG&E requests that the Commission authorize post-test year attrition adjustments for 2012 and 2013 in order to provide PG&E with the funds it deems necessary for those years to continue to provide safe and reliable service to customers, while offering PG&E a reasonable opportunity to earn the rate of return found reasonable by the Commission.

3. Procedural Background

A prehearing conference was held on February 19, 2010, and the Assigned Commissioner's Ruling and Scoping Memo was issued on March 5, 2010. On

July 29, 2010, Investigation (I.) 10-07-027 was instituted to allow the Commission to hear proposals other than those of PG&E and to enable the Commission to enter orders on matters not proposed by PG&E. A.09-12-020 and I.10-07-027 were consolidated for these purposes.

During May and June 2010, joint public participation hearings for this proceeding and A.09-09-013[1] were held in San Francisco, Fresno, Bakersfield, Ukiah, Santa Rosa, Oakland, Woodland, Red Bluff, San Jose, Salinas, and San Luis Obispo. In total, there were approximately 450 speakers who addressed a variety of issues ranging from impacts of rate increases on the various customer classes, suggestions for reducing PG&E's costs, renewable energy, State Proposition 16, energy assistance programs, PG&E's SmartMeter program, undergrounding of utilities, PG&E's practice of contracting out engineering and design work, rate design, and the Diablo Canyon Nuclear Power Plant.

Evidentiary hearings were held from June 21 through July 16 and on July 22, 2010. The Joint Comparison Exhibit was served on July 30, 2010.[2] Opening Briefs were scheduled to be filed on August 26, 2010 and reply briefs on September 20, 2010. However, on August 4, 2010, PG&E, the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN) and Aglet Consumer Alliance (Aglet) informed the assigned Administrative Law Judge (ALJ) that the parties were currently engaged in settlement negotiations. In order to permit further discussions, the ALJ granted those parties' request to

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1 By A.09-09-013, PG&E requested to increase the authorized revenue requirement for its natural gas transmission and storage services.

2 The Joint Comparison Exhibit is identified as Exhibit PG&E-69 and is received in evidence.

extend the filing dates for opening and closing briefs. Shortly thereafter, other parties to the proceeding were invited to participate in the settlement discussions, if interested.

On September 24, 2010, it was reported to the ALJ that significant progress among a number of parties had been made. The parties requested that the procedural schedule be suspended pending the submission of the next status report. That request was also granted.

On October 15, 2010, a settlement conference was held. Later that day, after the conference was concluded, a motion to adopt a test year 2011 GRC settlement agreement (Settlement Agreement) that resolved all but one issue in this proceeding was filed by PG&E on behalf of itself and 16 other parties (collectively, the Settling Parties). Opening briefs on the one remaining issue were filed on October 29, 2010, and reply briefs were filed on November 15, 2010.[3] Comments on the Settlement Agreement were also due on November 15, 2010. However, none were filed. This proceeding was submitted for decision on November 17, 2010, after the assigned ALJ determined that evidentiary hearing on the Settlement Agreement was not necessary.

4. The Settlement Agreement

The Settlement Agreement is attached to this decision as Attachment 1. The Settling Parties state that the principal public interest affected by this GRC is delivery of safe, reliable electric and gas service at reasonable rates, asserting that the Settlement Agreement advances this interest because it sets forth a

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[3] PG&E, DRA, TURN, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) filed opening and reply briefs. Aglet filed a reply brief only.

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 lower level than PG&E sought. The Settling Parties further assert that, taken as a whole, the Settlement Agreement is reasonable in light of the entire record, consistent with law, and in the public interest and request that it be approved.

4.1. The Settling Parties

The Settling Parties include PG&E; DRA; TURN; 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);[4] Energy Producers and Users Coalition (EPUC); Engineers and Scientists of California, Local 20 (ESC); Merced Irrigation District (Merced ID);[5] Modesto Irrigation District (Modesto ID);[6] South San Joaquin Irrigation District (SSJID); Western Power Trading Forum (WPTF); and Women's Energy Matters (WEM).

The Settling Parties represent a variety of interests other than that of the Applicant. 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

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

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

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

represents the interests of represented utility 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 professional 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.

4.2. Non-Settling Parties

This is not an all party settlement. Active parties that did not join in the Settlement Agreement include SCE, the Greenlining Institute (Greenlining), and the City and County of San Francisco (CCSF). SCE submitted the testimony of one witness, while Greenlining submitted testimony of two witnesses. Also, CCSF participated in this proceeding through the cross examination of a number of witnesses during evidentiary hearings. Neither SCE, nor Greenling, nor CCSF filed comments on the proposed settlement.

4.3. The Settling Parties' Litigation Positions

4.3.1. PG&E's Position

At the end of hearings, and as reflected in the Joint Comparison Exhibit,[7] PG&E's litigation position would result in base revenue requirements of

[7] The Joint Comparison Exhibit is identified as Exhibit PG&E-69 and is received in evidence.

$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. 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.

4.3.2. 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 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.

4.3.3. 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.

4.3.4. 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.

4.3.5. 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.

4.3.6. CFBF's Position

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

4.3.7. 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 to 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 Commission regulations. CCUE proposed enforcement mechanisms, such as balancing accounts and contempt proceedings, to ensure PG&E performs this work. CCUE also recommended that the Commission not rely on the Total Compensation Study.

4.3.8. 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 Federal Energy Regulatory Commission 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.

4.3.9. 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.

4.3.10. 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 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 Memoranda of Understanding (MOU) as part of Exhibit PG&E-16.

4.3.11. 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 Power Plant Costs in Plant Held for Future Use (PHFU).

4.3.12. 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.

4.3.13. Merced ID and Modesto ID Position

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

4.3.14. 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.

4.3.15. 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.

4.3.16. 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 activities; recommended that PG&E provide specific information to assist renewable projects to interconnect to its distribution system; recommended procedures to better ensure attention to distribution system maintenance, including in the territories of Community Choice Aggregators; and recommended imposing automatic penalties if PG&E continues to fund customer retention and economic development activities.

4.4. The Non-Settling Parties' Litigation Positions

4.4.1. Greenlining

In its testimony, Greenlining opposed PG&E's executive compensation bonus system, opposed PG&E's use of the Global Insight Study as support for its capital spending proposals; supported PG&E's proposal to increase and improve supplier diversity and inclusion; and opposed the level of PG&E's requested Economic Development Program expenses.

4.4.2. SCE

SCE presented rebuttal testimony that opposed DRA's proposal to set PG&E's AFUDC rate at a short-term debt rate, Aglet's comments on the Global Insight Study proposal of the economic impacts of PG&E's capital expenditure program, and certain Aglet comments on productivity.

4.4.3. CCSF

CCSF did not serve prepared testimony, but conducted cross examination in such areas as quality of service, above and below-the-line customer engagement activities, reprioritization of customer care expenses, SmartMeter deployment, community choice aggregation (CCA) fees, and customer satisfaction.

4.5. Terms of the Settlement Agreement

The Settlement Agreement is included as Attachment 1 to this decision. The related results of operation tables are included as Attachment 2. Key terms of the Settlement Agreement include:

- A revenue requirement increase in 2011 amounting to $183 million (6.1%) for electric distribution, $47 million (4.3%) for gas distribution, and $166 million (11.1%) for electric generation. This is in contrast to PG&E's request of $527 million (17.5%) for electric distribution, $208 million (19.2%) for gas distribution, and $329 million (22.1%) for electric generation.
- A further revenue requirement increase in 2012 amounting to $123 million (3.9%) for electric distribution, $35 million (3.1%) for gas distribution, and $22 million (1.3%) for electric generation. This is in contrast to PG&E's request of $181 million (5.1%) for electric distribution, $49 million (3.8%) for gas distribution, and $33 million (1.8%) for electric generation.
- A further revenue requirement increase in 2013 amounting to $123 million (3.7%) for electric distribution, $35 million (3.0%) for gas distribution, and $27 million (1.6%) for electric generation. This is in contrast to PG&E's request of $222 million (6.0%) for electric distribution, $64 million (4.8%) for gas distribution, and $33 million (1.8%) for electric generation.
- 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 agreed to brief this 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.

As detailed in the Settlement Agreement, the Settling Parties resolved a number of specific issues in reaching agreement on these revenue requirement increase amounts and levels. However, the resolution of many cost issues raised during this proceeding is considered subsumed in the overall settled revenue requirement amounts for the various segments of PG&E's operations such as electric distribution, gas distribution, energy supply, customer care, A&G expenses, shared services, depreciation, and capital-related costs. Also, the Settlement Agreement provides direction and guidance with respect to cost recovery, future GRC, and other filing requirements; customer service; accounting and accounting mechanisms; an audit of SmartMeter costs; and modification of the results of operations model for use in PG&E's next GRC.

4.6. Standard of Review

We have reviewed settlements as far back as at least 1988.[8] In doing so, we have often acknowledged California's strong public policy favoring settlements. This policy supports many worthwhile goals, such as reducing litigation expenses, conserving scarce resources of parties and the Commission, and allowing parties to reduce the risk that litigation will produce unacceptable results.

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.

We have specific rules regarding approval of settlements:

> "The Commission will not approve stipulations or settlements whether contested or uncontested, unless the stipulation or

[8] *See*, for example, Decision (D.) 88-12-083, 30 CPUC2d 189.

settlement is reasonable in light of the whole record, consistent with law, and in the public interest."[9]

4.7. Discussion

We have reviewed the Settlement Agreement, and, as discussed below, conclude that it is consistent with law, reasonable in light of the whole record, and in the public interest. However, as also discussed, certain requirements will be imposed on PG&E with respect to reprioritization and deferral of costs.

4.7.1. Consistency with Law

The Settlement Agreement is consistent with law. We do not detect, and it has not been alleged, that any element of the Settlement is inconsistent in any way with Public Utilities Code Sections, Commission decisions, or the law in general.

Regarding the process for developing the Settlement, the Settling Parties note that 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 the ALJ 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 indicate that they have devoted substantial time and effort to achieving this Settlement Agreement. Furthermore, the Settling Parties state that because the Settlement Agreement leaves only one issue

[9] Rule 12.1(d) of the Commission's Rules of Practice and Procedure (Rules).

unresolved, its consideration and adoption will promote the "just, speedy, and inexpensive determination of the issues presented." (Rule 1.2.)

We agree with the Settling Parties. While the development of the Settlement Agreement extended beyond the time allowed by the rules, it has significantly reduced the time and expense associated with Commission's deliberation of a fully litigated case. The 30-day limit is waived. In all other respects the process used by the Settling Parties in developing the Settlement Agreement, conducting settlement conferences, and filing the motion to adopt the Settlement Agreement are consistent with the Commission's Rules.

4.7.2. Reasonableness in Light of the Whole Record

PG&E's request has been sufficiently scrutinized through the direct testimony, rebuttal testimony and evidentiary hearing processes. As described above, in this proceeding, there were 20 active parties with diverse interests. The evidentiary record is substantial, consisting of 415 exhibits, including the testimony of 120 witnesses, as well as 2,911 pages of evidentiary hearing transcripts. The Joint Comparison Exhibit, which portrays parties' positions after evidentiary hearings were concluded, details hundreds of issues raised during the proceeding.

The following table compares the DRA and PG&E positions at the time of the Joint Comparison Exhibit with the Settlement Agreement proposal on a total GRC basis (electric and gas distribution and electric generation).

	PG&E	DRA	Settlement
	(Million of dollars)		
Present Rate Revenues	$ 5,581	$ 5,581	$ 5,581
2011 Authorized Revenue Requirement	6,645	5,762	5,977
Increase over Present Rate Revenues	1,064	181	396
% Increase	19.1%	3.2%	7.1%

2012 Authorized Revenue Requirement	$ 6,908	$ 5,877	$ 6,157
Increase over 2011 Authorized	263	115	180
% Increase	4.0%	2.0%	3.0%
2013 Authorized Revenue Requirement	$ 7,227	$ 5,983	$ 6,342
Increase over 2012 Authorized	319	106	185
% Increase	4.6%	1.8%	3.0%
Cumulative Increase in 2011	$ 1,064	$ 181	$ 396
Cumulative Increase in 2012	$ 1,327	$ 296	$ 576
Cumulative Increase in 2013	$ 1,646	$ 402	$ 761
Three-Year Cumulative Increase	$ 4,037	$ 879	$ 1,733
Electric Distribution	$ 2,165	$ 616	$ 918
Gas Distribution	$ 786	$ 26	$ 246
Electric Generation	$ 1,086	$ 237	$ 569

As shown, for the recommended test year 2011 revenue requirement level, the difference between PG&E and DRA alone amounted to $883 million. While the three-year (2011 test year and 2012 and 2013 attrition years) accumulated increase requested by PG&E amounted to slightly more than $4 billion, DRA recommended only $0.9 billion. Incorporating the positions of other parties would reduce the recommended increase further below that of DRA.

When looked at in total, the settlement produces a reasonable outcome. As shown above the cumulative settled revenue requirement increase of $1.7 billion for the years 2011, 2012, and 2013 is significantly less than the $4.0 billion amount requested by PG&E. The record in this proceeding supports reductions to PG&E's request but not to the full extent advocated by the various other parties. While recognizing that settlements are compromises of parties' positions, the fact that such a large number of parties, with such diverse interests and recommendations, were able to reach a compromise that was acceptable from their various viewpoints provides assurance that the overall result is reasonable. Additionally where specific issues were identified and resolved in the Settlement Agreement the results are reasonable and consistent with the record.

Aside from resolution of the lone outstanding issue in this GRC and how the Settlement Agreement may reflect aspects of that issue, we conclude that the revenue requirement levels reflected in the Settlement Agreement are reasonable.

Besides resolving the revenue requirement issues, the Settlement Agreement includes a number of guidelines and directions that are consistent with the record and reasonable. They address:

- Retention of the Vegetation Management Balancing Account.
- Allocation of work credits for Rule 20A projects.
- Allocation of electric RD&D project costs between generation and distribution, and, with certain limitations, placement of project results in the public domain.
- Establishment of DIMP and an associated one-way balancing account.
- Treatment of the postretirement benefits other than pensions and long term disability balancing account and associated costs.
- Treatment of certain Diablo Canyon Power Plant labor costs as operating expense rather than capital expenditures.
- Cost recovery treatment and guidelines related to the Diablo Canyon Steam Generator Replacement Project, Gateway Settlement Balancing Account, Colusa Generating Station, Humboldt Bay generating station, Hunters Point Power Plant site, and nuclear fuel payments.
- Below-the-line treatment of customer retention costs incurred by the Customer Care organization.

- Requiring an independent audit of PG&E's SmartMeter-related costs.
- Continuation of the SmartMeter Benefits Realization Mechanism.
- Treatment of the Commission's consultant costs for the SmartMeter evaluation as an eligible cost in the SmartMeter balancing accounts.
- Commitment of PG&E to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA fees.
- Rejection of reconnection fee adjustments.
- Approval of 8:30 a.m. to 5:00 p.m. as local office hours.
- Reduction of Non-sufficient Funds Fee to $9 from the current level of $11.50.
- Modification of PG&E's Below-the-Line Guidelines.
- Treatment of employee transfers from affiliates.
- Guidelines for meal expense records.
- Recovery of nuclear fuel and fuel oil carrying costs at short-term commercial paper rates.
- Removal of all Market Redesign and Technology Upgrade related revenue requirements from this proceeding.
- Denial of PG&E's requests for new balancing accounts for health care costs, New Business/Work at the Request of Others (WRO)/Rule 20; renewable energy projects, uncollectibles, emergencies and catastrophic events, and RD&D expenses.
- Use of the adopted 2011 rate base amounts in developing revenue requirements from future cost of capital proceedings.
- Use of adopted 2011 A&G expenses for use in determining administrative and general expenses in related proceedings, if needed.
- Approval of the Memorandum of Understanding between DisabRA and PG&E.
- Elimination of the requirement for PG&E to prepare total factor productivity studies.

- Elimination of the requirement for PG&E to include information about long-term incentives that are not funded by ratepayers, in future total compensation studies.
- Review of the Results of Operations model for use in PG&E's next GRC.
- Justification of new types of costs in the next GRC.
- Suspension of AFUDC accruals for the ten Transform Operations projects identified by TURN.
- Employee training and hiring testimony requirements for PG&E in its next GRC.

4.7.3. Non-tariffed Products and Services

The Settlement Agreement adopts PG&E's proposal to be allowed to expand its offerings of non-tariffed products and services (NTP&S).[10] As discussed below, we agree that PG&E should be allowed to expand its list of approved NTP&S offerings, but we will require an annual report from PG&E on their new offerings as they suggested in the comments on the proposed decision. The Settlement Agreement also specifies the costs and revenues associated with the expansion of services shall be treated on a cost of service basis and that PG&E's proposals concerning the 50/50 net revenue sharing mechanism and a sharing mechanism for shareholder capital shall not be adopted. This aspect of the settlement is reasonable.

The Commission's NTP&S program was designed, not to allow utility management to enter markets unrelated to their core function of providing good utility service, but instead to encourage that management to find and exploit economies of scope available in any underutilized capital or capacity already

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[10] *See* Exhibit PG&E-4, Chapter 12.

acquired by ratepayers and used for the provision of the utility service.[11] While it is our preference that this process of exploitation of economies be performed by the utility's unregulated affiliates, under the purview of our Affiliate Transactions Rules, company management may find this approach impractical and decide, instead, to utilize our NTP&S program. If so, we need to be ensured that this program will not divert utility expertise and other resources enough to affect utility service, will not distort existing non-utility markets, and reasonably reimburse ratepayers for the use of their assets for the project.

Therefore, our NTP&S Rule VII of the Affiliate Transactions Rules requires a utility to describe their proposed NTP&S project in an advice letter which also includes the following showings: 1) identification of the underutilized or excess capacity acquired for the utility service; 2) the steps that will be taken to ensure that the project will not affect the quality or cost of the utility service; 3) proof that the provision of the NTP&S will not distort non-utility markets or be in some way anticompetitive; and 4) a reasonable mechanism to divide the proceeds of the project between ratepayers and shareholders.[12]

PG&E's proposal is that it be allowed to provide NTP&S that have been already approved by the Commission for other utilities without the advice letter requirement.[13] PG&E has found the advice letter approval process to be

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[11] The classic example given was leasing available land for Christmas tree lots under transmission lines. See D.97-12-088, as revised by D.06-12-029. The most recent introduction of this program by this Commission was for the water utilities in D.10-10-019.

[12] *See* D.06-12-029, Appendix A-1, Rule VII C.

[13] For new NTP&S categories, PG&E is currently required to make Tier 3 advice letter filings, which require Commission approval by resolution.

cumbersome, indicating experiences of eight months to one year for approval. PG&E states that its proposal would create a catalogue that is more consistent statewide and reduce the administrative burden of advice letter filings for NTP&S that are already being offered in the state and should need no additional approval.

PG&E provides Table 12-2, in Exhibit PG&E-4, as an illustrative list of NTP&S categories currently offered by other California energy utilities. We note that all categories of NTP&S identified in Table 12-2 were listed by these utilities as products or services already offered in 1997 at the time this program and our rules were promulgated. We allowed the utilities to continue offering these categories without review by Commission staff for compliance with the new rules. At that time, PG&E listed 27 categories that they were already offering. We required new categories for each utility to be approved through advice letter filing for review, correction and finally disposition by the Commission.

We are not convinced that elimination of all reporting requirements, even for NTP&S categories and associated products or services offered by other utilities, is appropriate. It is not clear that, in light of the Affiliate Transaction Rules, every existing category should also now be applicable to PG&E without any review or verification. For instance, PG&E may have different levels of underutilization or excess capacity than utilities already offering a particular product or service. Also, the Commission needs assurance that appropriate steps are taken by PG&E such that the provision of NTP&S in a particular category will not affect the quality or cost of the utility service. However, in general, we agree that PG&E should be allowed to offer NTP&S that are already being offered by the other major energy utilities in a more expeditious manner than is currently available. Therefore, PG&E shall be required to provide an annual information-only report to the Energy Division that describes, on a prospective basis, PG&E's specific plans for expansion into any of the areas currently authorized for the other utilities. The report should also be made available to the parties to this proceeding as well as the parties to Rulemaking 05-10-030. The purpose of the report is to permit the Commission and interested parties to confirm that PG&E's expanded NTP&S offerings in this category mirror the NTP&S already offered by one of the other energy utilities in their approved categories for NTP&S. As part of the report, PG&E should identify 1) the underutilized or excess capacity used to provide the NTP&S; 2) the steps that will be taken by PG&E to ensure that the project will not affect the quality or cost of the utility service; and 3) proof that the expanded NTP&S will not distort non-utility markets or be anticompetitive.[14] We determine this reporting requirement, in lieu of a formal advice letter filing, is sufficient due to the limited nature of the proposal, that is it will only apply to those NTP&S categories and associated products or services specifically described in other utilities' filings, and the costs and revenues will be treated on a cost of service basis.[15] However, in order to allow time for the Commission and interested parties to confirm that PG&E's expanded NTP&S offerings are appropriate and justified, PG&E should

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[14] This reporting requirement was proposed by DRA, TURN, and PG&E in their opening comments on the proposed decision of ALJ Fukutome and the alternate proposed decision of Commissioner Peevey.

[15] PG&E will include a new forecast of the costs and revenues in its information-only filing. In the test year and the attrition years, if the revenues or costs are different than forecasted the differences fall on shareholders rather than ratepayers. Such "cost of service" ratemaking has been used for NTP&S under PG&E's existing NTP&S catalog since the late 1990s and will be maintained.

not offer any such expanded service until at least 30 days after the issuance of the annual information-only report.

4.7.4. Reprioritization and Cost Deferrals

While the record supports the revenue requirement levels that are reflected in the Settlement Agreement, the Commission's expectations with respect to how authorized funds should be spent and PG&E's accountability with respect to how those funds are spent should be clarified.

While the Commission sets the adopted GRC revenue requirement based, in large part, on programs and projects proposed by PG&E, which are reviewed in the GRC proceeding and adopted in the GRC decision, PG&E may not actually expend funds in that exact manner. For instance, regarding certain distribution costs in this proceeding, PG&E states:

> In an effort to remain within the capital and expense expenditure levels imputed from the 2007 GRC Settlement Agreement, PG&E adjusted work where possible by focusing on work in higher priority categories.[16]

Certain parties were concerned that the process of reprioritization and deferral of certain costs has resulted in projects identified and adopted in a prior GRC being deferred by PG&E and included again in its request for this proceeding. To address this concern, DRA, in its testimony, excluded a number of such electric distribution activities including replacement/reinforcement of poles, replacement of underground cables, preventative maintenance and equipment repair, electric line patrol and inspection, network work and projects,

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16 *See*, for instance, Exhibit PG&E-3 at 1-35.

streetlight group replacements, pole restoration, and substation maintenance, as well as the gas meter protection program.[17]

It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled, and there may be reprioritization. This process is expected and is necessary for the utility to manage its operations in a safe and reliable manner. The Commission has recognized the concept of reprioritization, in part, as follows:

> We conclude that this is not deferred maintenance in the sense we discussed previously. The work was not deferred to improve the utility's financial position. We do not intend to push utilities to spend the earmarked maintenance dollars simply to avoid risk of disallowance in a future proceeding. Because we hold the utility accountable to provide safe, reliable and efficient service, the utility should be able to move maintenance dollars from one account to another for the reasons provided in this case . . . [18]
>
> In summary, we should note that the issue in this instance is not deferred maintenance; rather, it is whether the utility should have the flexibility to shift earmarked funds if it is in the ratepayers' interest to do so. We conclude that if the utility has a valid reason based on economic or other considerations, then it should have the flexibility. This is simply prudent management.[19]

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[17] TURN and CFBF made similar types of adjustments for cost deferrals.

[18] D.83-12-068, 14 CPUC2d 15, 146.

[19] D.94-12-068, 16 CPUC2d 721, 782.

However, the fact that this flexibility is available to the utility does not mean that everything the utility ends up doing is necessary or reasonable. The Commission has disallowed costs of activities that were requested and included in prior GRC authorizations, deferred, and re-requested in another GRC. For instance, in PG&E's last GRC, the Commission stated:

> The Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. Here, there is no dispute that PG&E received funding for lead paint and PCB abatement in its prior GRC proceeding, and that PG&E seeks funding for these activities a second time in the current proceeding.[20]

And:

> In order to find that the Settlement Agreement is consistent with the law, which includes adherence to long-established Commission precedent, we must be satisfied that all of PG&E's lead paint and PCB abatement costs are excluded from the O&M expenses adopted by the Settlement . . . [21]

As indicated, reprioritization and cost deferrals may be necessary and reasonable, and, if not, cost disallowance of previously requested activities which were deferred and re-requested may be appropriate. With respect to reprioritization and deferred cost issues in this GRC, the Settlement Agreement does not indicate specific outcomes; however it is assumed that the settled position reasonably reflects Commission precedents as noted above, taking into consideration the strengths and weaknesses of parties' positions. The Settlement Agreement does state that:

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[20] D.07-03-044 at 93 (footnote omitted).

[21] D.07-03-044 at 95.

> 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.[22]

While we reaffirm that it is the utility management's prerogative and responsibility to provide safe and reliable service by reprioritizing and deferring activities as necessary, the Commission must be assured that the process is reasonable. We have concerns in that respect. For instance, despite any financial implications of exceeding authorized cost levels, the utility does have the responsibility to spend what is necessary to ensure safe and reliable service. To the extent a utility uses authorized cost levels as a reason for deferring activities, the Commission must be assured that such deferrals are otherwise reasonable especially with respect to safe and reliable service. Also, justified or not, reprioritization and deferrals undermine the basis for the Commission's determination of the reasonableness of the utility's GRC request and the extent of the authorized revenue requirement. Much of what is authorized is based on the utility's depiction of its needs and associated costs. Those needs and costs are tested by the GRC process. Reprioritized needs and associated costs may not be so tested and may not result in the most efficient use of funds. In light of these concerns, we will impose certain requirements on PG&E, as a step in ensuring

[22] Settlement Agreement, Article 4.11.

that any reprioritization processes are reasonable and result in the best use of ratepayer funds.

First, in order for the Commission to better understand the ongoing effects of reprioritizations and deferrals, PG&E should provide the following expense and capital expenditure information for electric distribution, electric generation, and gas distribution.[23]

<u>Within 90 days of the issuance of this decision</u>:

- PG&E's authorized budgeted amounts[24] for 2011, as of January 31, 2011, by major work category (MWC), with an explanation of any differences with what is assumed in the Settlement Agreement for 2011.

<u>By March 31, 2012</u>:

- PG&E's authorized budgeted amounts, by MWC, for 2012, as of January 31, 2012.
- The recorded amounts for 2011, by MWC, with explanations for significant deviations from PG&E's January 31, 2011 authorized budget for 2011.

<u>By March 31, 2013</u>:

- PG&E's authorized budgeted amounts, by MWC, for 2013, as of January 31, 2013.
- The recorded amounts for 2012, by MWC, with explanations for significant deviations from PG&E's January 31, 2012 authorized budget for 2012.

Also, in its next GRC, as part of its showing, PG&E should fully describe any reprioritizations and deferrals of costs explicitly identified in the Settlement

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[23] This information should be provided through compliance filings in this docket. Energy Division should report to the Commission if it observes any spending patterns that are of concern with respect to the provision of safe and reliable service.

[24] Budgeted amounts are those authorized by PG&E management.

Agreement or costs that can reasonably be imputed from the Settlement Agreement. PG&E should fully explain its reprioritization process, justify deferrals of specific activities and projects, and justify the implemented higher reprioritized activities and projects that were not identified in this GRC. For activities and projects that were deferred and are now being re-requested, PG&E should fully explain why they are needed now when they were able to be deferred before. The Commission will be critical in its evaluation of previously requested activities or projects that were deferred and re-requested keeping in mind that the utility has the obligation to maintain its operations and its plant in the condition to provide efficient, safe and reliable service, even if that condition requires more expenditures than the Commission has authorized.[25]

4.7.5. Gas Distribution Pipeline Safety Reporting

Due to the Commission's responsibilities and concerns regarding gas pipeline safety, we will impose additional reporting requirements related to gas distribution pipelines.[26] We will require PG&E to submit semi-annual gas distribution pipeline safety reports to the Directors of the Commission's Consumer Protection and Safety Division and Energy Division. The requirements of the reports are detailed in Attachment 5 to this decision. Reports should cover activity over the first six-month period and second six-month period of the calendar year and continue until further notice of the Commission.

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[25] For example, *see* D.83-12-068, 14 CPUC2d 15, 66.

[26] Gas transmission pipelines issues are not within the scope of this proceeding, but are instead addressed in PG&E's Gas Transmission and Storage proceeding, A.09-09-013.

4.7.6. Financial Health

Aglet included testimony on the financial condition of PG&E, which Aglet characterizes as now being very good. With respect to PG&E's rise in credit ratings and stock prices since its bankruptcy in 2001, Aglet asserts the central feature of these financial improvements has been strong cash flows and access to capital. PG&E does not dispute Aglet's assertions and acknowledges that it has very strong access to capital because of its strong balance sheet and its ability to raise capital both from equity and debt financing.

The evidence demonstrates that PG&E is financially healthy. For the period covered by this GRC, the Settlement Agreement will provide PG&E with sufficient revenues to maintain its financial health, provide adequate service, and make necessary capital investments.

4.7.7. The Public Interest

We agree with the Settling Parties' position that the Settlement Agreement is in the public interest. There are no allegations, and we do not detect, that any element of the Settlement Agreement is inconsistent in any way with the public interest. Settlement avoids costs of further litigation and conserves resources of the parties and the Commission. In this case, it provides reasonable outcomes that are acceptable to a large number of parties representing a broad spectrum of interests.

Settling Parties assert and we agree that the principal public interest affected by this GRC is delivery of safe, reliable electric and gas service at reasonable rates, and the Settlement Agreement advances this interest because it sets forth a compromise that significantly reduces the revenue sought by PG&E while providing PG&E a test year revenue requirement increase and predictable attrition allowance.

Besides providing reasonable revenue requirement levels for electric distribution, electric generation and gas distribution, the Settlement Agreement furthers the public interest (such as safe and reliable service, ratepayer safeguards, and levelized competitive playing fields) by:

- Retaining the current one-way Vegetation Management Balancing Account, whereby any unspent amount will be returned to ratepayers.
- With respect to Rule 20 undergrounding projects, allowing communities with projects already in progress to continue with their projects even if they exceed the 5-year allowable borrowing period.
- Establishing of a one-way balancing account mechanism for the gas related DIMP that covers developments and improvements in such areas as preventative maintenance, leak surveys, operator qualifications and training. Any net unspent funds from this program will be returned to customers in the next GRC.
- Allowing PG&E to file a subsequent application to recover additional site-specific environmental remediation costs to the extent necessary to accommodate the development plan ultimately adopted for the Hunters Point site.
- Requiring PG&E to record customer retention costs incurred by its Customer Care organization below-the-line.
- Committing PG&E to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA service fees.
- Modifying PG&E's below-the-line guidelines to provide for an annual compliance review, as well as identification of additional below-the line activities and more thorough accounting and employee training.
- Advocating Commission approval of the MOU between PG&E and DisabRA regarding accessibility and safety issues for the disabled.
- Providing for an independent audit to ensure proper booking and allocation of costs and benefits related to PG&E's

SmartMeter program and 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 account.

We conclude that the Settlement Agreement is in the public interest.

4.7.8. Clarifications

The Settlement Agreement designates the Energy Division to be responsible for overseeing the audit process. We clarify that this responsibility does not fall on the Energy Division in particular, but on Commission staff in general, with specific responsibility being designated by Commission management based on staff availability.

It should be noted that, by the terms of the Settlement Agreement, if PG&E prevails on the issue of the rate of return for electromechanical meters replaced by SmartMeters, a $44 million revenue requirement increase will be added to the adopted electric distribution revenue requirement. If TURN prevails, the adopted electric revenue requirement would remain as indicated in the Settlement Agreement. To the extent that this decision adopts a different ratemaking treatment than proposed by either PG&E or TURN, the Settlement Agreement is modified in that respect.

4.7.9. Conclusion

The Settlement Agreement is consistent with law. With the additional requirements related to NTP&S, reprioritization and cost deferrals, and gas distribution pipeline safety reporting, and with minor clarification, as discussed, the Settlement Agreement is reasonable and in the public interest. It should and will be adopted.

The lone issue that was not resolved by the Settlement Agreement relates to the ratemaking treatment for meter devices replaced by SmartMeters.

5. Rate of Return on Meter Devices

In deploying SmartMeters throughout its electric distribution system, PG&E must retire the replaced meters, principally older electromechanical meters, many of which could otherwise provide useful service for a number of years. In A.05-06-028, the proceeding that resulted in the initial authorization of Advanced Metering Infrastructure (AMI) deployment for PG&E (D.06-07-027) and A.07-12-009, the proceeding that resulted in authorization of the SmartMeter Upgrade for PG&E (D.09-03-026), PG&E proposed ratemaking for the retired electromechanical meters, by which the original cost of the meters would be deducted from both the electric plant in service balance as well as the depreciation reserve balance. The result of that ratemaking is that, for rate recovery, the undepreciated balance of the electromechanical meters is amortized over the estimated remaining life of electric meters (approximately 18 years for 2011) with the unamortized balance being included as an element of rate base and earning the authorized rate of return. That is, there would be no effect on rate base compared to what would occur if the electromechanical electric meters had continued to be used and useful and were not replaced by SmartMeters. No party expressed opposition to this proposed ratemaking in either A.05-06-028 or A.07-12-009.

In this GRC proceeding, TURN has taken the position that the retired electromechanical meters are no longer used and useful and therefore should be excluded from rate base, resulting in PG&E earning no rate of return on the undepreciated balance as it is amortized over the approximate 18-year timeframe. PG&E served rebuttal testimony opposing TURN's position arguing that the Commission has already decided that there would be no net impact on net plant to be included in rate base on account of these retirements, and TURN's efforts to re-litigate this matter should be rejected.

The Settlement Agreement excluded costs associated with this issue and provided parties with the opportunity to brief the merits of TURN's proposal for Commission consideration and decision, with the understanding that, if PG&E prevailed, the appropriate related costs should be added to the Electric Distribution revenue requirements for 2011. Dates for opening and reply briefs were set by the assigned ALJ. Opening and reply briefs were filed by TURN, PG&E, DRA, SCE and SDG&E. Aglet filed a reply brief only. In general, TURN's position is supported by DRA and Aglet, while it is opposed by PG&E, SCE and SDG&E. In resolving this issue, a number of arguments presented in briefs were considered, as discussed below.

5.1. Addressing the Issue at this Time

In considering this issue, as advocated by TURN, rebutted by PG&E, and briefed by the various parties, the threshold argument that needs to be addressed is whether the ratemaking for meter devices replaced by SmartMeters has already been addressed and decided by the Commission in D.06-07-027 and D.09-03-026, and, therefore, whether it is appropriate for TURN to raise the issue in this proceeding.

PG&E states that it specifically addressed the ratemaking treatment of the electromechanical meters in its Initial AMI application, A.05-06-028. PG&E's ratemaking proposal was as follows:

> 3. Retirements of Plant
>
> As the AMI meters are deployed, replaced existing meters will be retired at their original cost. The retirement of these non-AMI meters is accomplished through a simple reduction to plant of the original cost installed with an equal and offsetting entry to

> accumulated depreciation. Therefore, there is no impact to the net book value (plant less accumulated depreciation). Because of the group depreciation accounting used by PG&E, any un-recovered book investment will be recovered over the average life of the depreciation group.[27]

Contrary to TURN's current position that rate base should be reduced to account for the undepreciated component of the electromechanical meters, PG&E's proposal was that rate base (i.e., net book value) be unaffected by the retirement. PG&E notes that neither TURN nor any other party opposed this aspect of PG&E's Initial AMI application, and that the Commission approved its proposal as follows:[28]

> 1. Pacific Gas and Electric Company (PG&E) is authorized to deploy the proposed Advanced Metering Infrastructure (AMI) project as described and modified by this decision.
>
> 2. PG&E's electric and gas allocation proposals are approved. PG&E shall file an advice letter in compliance with this decision in not less than 15 days, or more than 30, to implement PG&E's rate proposals to collect the revenue requirement and modify its preliminary statements for the gas and electric departments establishing the gas and electric balancing accounts as adopted in this decision. The advice letter shall be effective upon its approval by the Commission.

PG&E states that it made the same proposal in its SmartMeter Upgrade application, A.07-12-009, and again it was unopposed. PG&E indicates the Commission approved it as follows:[29]

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[27] A.05-06-028, Exhibit 5 at 5-5.

[28] D.06-07-027, Ordering Paragraphs (OPs) 1 and 2.

[29] D.09-03-026, OPs 1 and 2.

1. Pacific Gas and Electric Company (PG&E) is authorized to proceed with the proposed SmartMeter Upgrade, subject to the conditions and costs specified in this decision.
2. PG&E's general cost recovery proposal is adopted.

PG&E argues that given that PG&E expressly addressed the issue of the ratemaking treatment to be accorded the electromechanical electric meters in both the Initial AMI and Upgrade Proceedings, and that TURN was an active party to both cases, TURN should not be allowed now to re-litigate those issues in this GRC.

SDG&E made a similar argument in its opening brief.

5.1.1. Discussion

First, it should be clarified that in D.06-07-027, the Commission did not authorize the deployment of SmartMeters to replace all existing electromechanical electric meters, as is now the case. In D.06-07-027, the Commission indicated:

> At that point in time, PG&E's AMI proposal consisted of metering and communications infrastructure as well as the related computerized systems and software. It is often overly-simplified to imply that only meters are involved. In fact, in most instances, PG&E will not replace residential meters with new meters – most of the existing inventory will be retrofitted with communications modules and redeployed.[30] (Footnotes omitted.)

Also, in D.09-03-026, the Commission indicated:

> In PG&E's original AMI Application, PG&E proposed deployment of electromechanical electric meters for the majority of its residential electric service customers. The remainder of the residential as well as all commercial customers would receive solid state meters.

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[30] D.06-07-027 at 2-3. Footnote 3 to this quotation states that PG&E's plan was to retrofit 54% of the existing electric meters and 96.1% of its existing gas meters.

> According to PG&E, for deployment to date, this meter mix has worked as intended and, accordingly, has met the objectives of PG&E's original AMI Application. In the current application, PG&E proposes a transition in this mixture to the deployment of solid state meters ubiquitously. PG&E states that the solid state meter will be the platform for the intelligent, integrated metering solution that will enable PG&E to provide a number of new capabilities including a HAN gateway device (enabling price signals, load control and near real time data for residential electric customers) and load limiting disconnect switches . . . [31]

Therefore, while PG&E's ratemaking proposal in A.05-06-028 is the same as in A.07-12-009 and the same as what is reflected in its GRC application, it would have been applied to the replacement of fewer electromechanical meters than anticipated in A.07-12-009 with solid state meters that did not have the full capabilities of the SmartMeters eventually authorized by D.09-03-026 in A.07-12-009.

Also contrary to PG&E's assertion, Ordering Paragraph 2 in D.09-03-026, which adopted PG&E's cost recovery proposal, did not adopt PG&E's ratemaking proposal for meter devices that are replaced by SmartMeters. This particular ratemaking proposal was not included as part of PG&E's general cost recovery proposal that is discussed in Section 12.1 of D.09-03-026 and adopted in Ordering Paragraph 2. The ratemaking proposal at issue was instead an element of PG&E's revenue requirement methodology.[32] That methodology was not specifically adopted in an ordering paragraph, however Conclusion of Law 50 of

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[31] D.09-03-026 at 18.

[32] Retirements of plant, as quoted by PG&E, is discussed in Chapter 2, Revenue Requirement, in Exhibit 4 in A.07-12-009. PG&E's cost recovery proposal is discussed separately in Chapter 1 of that exhibit.

D.09-03-026 states that the use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the SmartMeter Upgrade is reasonable,[33] and PG&E's proposals with respect to retirements of plant are reflected in that model.

Therefore, while the applicability of the meter retirement proposal is slightly different in A.05-06-028 than in A.07-12-009 and this GRC, it is clear that, (1) in both prior proceedings, PG&E's meter retirement ratemaking proposal was consistent with what is proposed in this GRC proceeding, (2) no party addressed that proposal in the prior proceedings, and (3) in D.09-03-026, the Commission reflected PG&E's meter retirement ratemaking proposal in the ratemaking treatment for the SmartMeter program. However, in recognizing that no party addressed PG&E's proposal in either AMI proceeding and that neither D.06-07-028 nor D.09-03-026 contains specific discussion of PG&E's ratemaking proposal for retired meters or includes findings, conclusions or ordering paragraphs in which this issue is specifically identified, it is also clear that PG&E's ratemaking proposal for meter retirement was not specifically adopted or litigated in either A.05-06-028 or A.07-12-009. Therefore, TURN's recommendation in this proceeding is not, as characterized by PG&E, a re-litigation of the issue. We will not speculate as to why parties did not choose to litigate this issue in either of PG&E's AMI proceedings. That fact that they did not do so is, in itself, insufficient reason to preclude the issue from being addressed in this proceeding. What is of more significance is that the issue is important and relevant, and the Commission likely did not fully understand and

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33 No party disputed the use of PG&E's results of operations model for the purpose of calculating the revenue requirements associated with the SmartMeter Upgrade.

consider the ramifications of PG&E's proposed ratemaking in those prior proceedings.

That it is the lone disputed issue in this GRC demonstrates the importance and relevance of PG&E's ratemaking proposal for retired meters. There are significant financial consequences associated with TURN's recommendation that results in the exclusion of rate of return costs of approximately $44 million in 2011, $132 million over the three-year GRC cycle, and $418 million over 18 years. Neither the magnitude of the net plant balance for prematurely retired meters, nor the associated rate of return costs were identified in PG&E's prior AMI testimony. It was not until this GRC proceeding that the $341 million net plant balance and the associated $44 million rate of return cost for 2011 were openly discussed. Also, in briefs, parties have made a number of arguments and cited precedential Commission actions that are relevant and significant, but which were never brought up and considered in the prior AMI proceedings. Consequently, there is good reason to believe that PG&E's ratemaking proposal for retired meters was not fully understood and considered by the Commission in the two prior AMI proceedings. The Commission should now fully examine this issue and determine whether the outcome in D.09-03-026 is just or needs to be changed.[34]

5.2. Facts Not in Dispute

In considering the merits of this issue, we note that a number of relevant facts, as follows, are not in dispute:

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[34] We do not agree with the DRA proposal to defer consideration of the issue to the next GRC. There is sufficient record to fairly resolve the issue now.

- The Commission encouraged the electric utilities, including PG&E, to consider and implement AMI. PG&E responded with an initial AMI proposal in June 2005 (A.05-06-028) and a revised proposal in December 2007 (A.07-12-009).
- In A.07-12-009, the Commission found PG&E's SmartMeter Upgrade proposal to be cost-effective, in that estimated incremental benefits exceeded incremental estimated costs.
- Electromechanical electric meters replaced by SmartMeters are no longer used and useful.
- In both A.05-06-028 and A.07-12-009, PG&E proposed to reduce both the electric plant in service balance and the depreciation reserve balance by the original cost of the electromechanical electric meters that are replaced by SmartMeters. This produces a result that is the same as leaving the retired meters in plant, continuing depreciation over the estimated life of that asset and receiving a rate of return on the undepreciated balance. No party expressed any opposition to PG&E's proposal in either A.05-06-028 or A.07-12-009.
- The undepreciated portion of electromechanical electric meters that will be replaced by SmartMeters is estimated to be $341 million at the beginning of 2011. Both PG&E and TURN propose to amortize the $341 million balance over the 2011 through 2028 time period (18 years), at $18.9 million per year.
- For test year 2011, PG&E's proposal to include the $341 million net plant balance in rate base, and thus in rates, imposes a financial burden on ratepayers of approximately $44 million, when compared to TURN's proposal to exclude that balance from rate base and rate of return cost recovery.

5.3. Commission Precedents

To support their positions, parties have cited a number of relevant Commission decisions regarding cost recovery as it relates to this issue, including the following:

- D.92-08-036 – The Commission adopted a settlement between SCE, SDG&E and DRA which allowed a 48 month amortization of remaining investment in San Onofre Nuclear Generating Station Unit 1 (SONGS 1). After shutdown of SONGS 1, the remaining unamortized investment was allowed to earn a rate of return, which, after taxes, was fixed at the then current authorized embedded cost of debt.[35]

- D.95-12-063 – Regarding electric industry restructuring, the Commission determined that transition cost recovery for remaining net investment should be at a reduced rate of return. The Commission noted that "Allowing recovery of remaining net investment associated with SONGS 1 plant at the embedded cost of debt was reasonable at the time, given the risks faced by the utilities under the then-current regulatory structure. However, today's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to imposition of a nonbypassable charge on distribution system customers (as described in greater detail below) which decreases utility business risk. We will adopt 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net book value to reflect the reduced risk. We will set the return on the debt portion of net book value at the embedded cost of debt."[36]
- D.97-11-074 – Regarding electric restructuring, the Commission stated, "In allowing the recovery of generation plant-related transition costs, we have, in effect, allowed the utilities to recover costs of plants that may no longer be used and useful in the new competitive marketplace."[37]
- D.96-01-011 – Consistent with D.95-12-063, the Commission adopted the same recovery of 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net book value regarding Incremental Cost Incentive Pricing (ICIP) pricing for SONGS 2 and 3. The Commission noted, "In

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35 45 CPUC2d 274, 276.

36 64 CPUC2d 1, 62.

37 76 CPUC2d 627, 737.

D.95-12-063, we propose a general policy for stranded cost recovery. There we decided that while use of a debt-return is appropriate for the debt component of a stranded investment, a return of 90% of the debt return is appropriate for the non-debt (i.e., equity) share of the stranded investment . . . "[38]

- D.83-08-031 – The Commission addressed early retirement of Pacific Telephone and Telegraph Company's (Pacific's) retired equipment, and allowed rate base treatment for those assets affected by the early retirements, except for those retirements caused by the company's affirmative marketing practices designed to enhance sales of the Bell System (referred to as Pacific's migration strategy). The Commission stated "The record in this proceeding indicates that earlier than anticipated retirements are the largest cause of the decline in Pacific's book depreciation reserve as a per cent of plant. Growth fluctuations are a secondary cause. Whether we call this condition a reserve deficiency or a stranded investment does not matter. Whether the problem has been caused by the economic trends of the day, the migration strategy, or, most likely, some combination of the two, does make a difference. The difference lies in how costs are allocated between Pacific's shareholders and ratepayers. That portion not resulting from the migration strategy should be paid by ratepayers."[39]
- D.84-09-089 - In the context of the liquefied natural gas (LNG) project abandonment the Commission stated, "As set forth in D.83-12-068 as modified by D.84-05-100, our policy of rate recovery for abandoned plants provides for a sharing of costs between ratepayers and shareholders during periods of great uncertainty. Under this policy, if the applicants declared the LNG project abandoned, we would allow them to recover their direct expenditures, but not their AFUDC."[40] However, the

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[38] 64 CPUC2d 241, 272.

[39] 12 CPUC2d 150, 167.

[40] 16 CPUC2d 205, 230.

Commission noted that, even for project abandonments, the Commission had recognized an exception where benefits could be shown to customers, indicating, "A review of the exceptional cases is presented in D.92497 dated December 5, 1980. In these abandoned project cases we allocated the direct feasibility costs to ratepayers and AFUDC costs to shareholders. The costs borne by ratepayers were then amortized over a period of years. We have allowed the utility to rate-base a portion of the unamortized costs only when the residual value or potential benefits were likely to accrue to ratepayers. Otherwise, we considered such treatment as an inappropriate shifting of risk to the ratepayers."[41] Additionally, this decision addresses PHFU, an exception to the used and useful principle, stating, "One exception [to "used and useful"] is PHFU. This is primarily land which has been purchased by a utility for use at a later date. We have allowed such property to be included in ratebase only when there is a definite and reasonably imminent plan for its development. Property which fails to meet this test is excluded under the used and useful principle."[42]

- D.84-05-100 – With respect to the abandonment of PG&E's Montezuma coal project, the Commission took into consideration that the overall abandonment resulted in a net gain, stating, "Also, we will allow PG&E carrying costs of $ 4.3 million. That sum is equal to the AFUDC accumulated for the Montezuma project through December 31, 1981, by which date PG&E had received bids conforming to its instructions and had accepted Sunedco's bid. (D.82-12-121, Findings of Fact 17-19.) We allow the carrying costs because ratepayers derived substantial benefits from the project, in the form of profits from the sale, even though the project never produced electricity. Thus, PG&E is entitled to its carrying costs through the date indicated."[43]

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41 16 CPUC2d 205, 229.

42 16 CPUC2d 205, 228.

43 15 CPUC2d 123, 127.

- D.85-12-108 – Regarding SDG&E's proposal to store power plants that could no longer be operated economically, the Commission determined that as to those plants likely to remain retired, there should be sharing of the burden, stating, "The specific ratemaking treatment for these plants will essentially follow the suggestion of UCAN. The UCAN position is that the undepreciated balance of the prematurely retired plants be amortized over five years with no return earned. The FEA recommended a longer period - nine years or three rate cases. We find that the UCAN has shown that the two rate case periods or about five years provides an appropriate sharing of the burden between the ratepayers and shareholders."[44] However, the Commission did provide an exception to the used and useful principle for one unit that might benefit customers, indicating, "We will adopt the company's suggestion for South Bay 3. We find that it is the last to be stored, assume that it is, therefore, the most economical of the stored plants, and because of the uncertain reliability inherent in SDG&E's resource plan we will allow SDG&E to treat it as plant held for future use. Moreover, South Bay 3 is useful as a "yardstick" in bargaining for firm purchased power . . . We believe that both ratepayers and shareholders benefit by retaining the newer more efficient plants in rate base and excluding the older fossil fuel plants."[45]
- D.85-08-046 – The Commission focused on who should bear the burden of unrecovered costs in the Humboldt Bay plant retirement and, in rejecting PG&E's attempt to bring other power plants that may have operated for longer than intended into consideration, the Commission stated, "With respect to PG&E's equity argument, we observe that plants which have exceeded their estimated useful lives have been fully depreciated. Thus, the shareholder already has recovered his entire investment and a fair return on that investment from the ratepayer. The ratepayer who has paid for the entire plant is entitled to receive

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[44] 20 CPUC2d 115, 143.

[45] 20 CPUC2d 115, 143.

any additional benefit from the plant's continued operation. In the case of a premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits."[46]

- D.92-12-057 – In the case of the Geysers Unit 15 premature retirement, the Commission relied on the Humboldt Bay plant retirement as a precedent in ruling that PG&E could not offset the shorter life of Unit 15 against other plants having a longer life, using rules of group accounting. The Commission did offer that PG&E could raise the group accounting argument later, if it could make a stronger showing. The Commission also stated, " . . . We once again endorse our longstanding regulatory principle that shareholders should earn a return only on used and useful plant . . . "[47] PG&E was thus authorized a four-year amortization for the remaining net plant cost, with no return on the unamortized balance.
- D.07-05-026 – In addressing cost recovery related to divestiture and/or market valuation of generation assets, the Commission stated, "The principal public interest affected by this proceeding is delivery of safe, reliable electric service at reasonable rates. The Settlement Agreement advances this interest because it permits PG&E to recover reasonable costs of complying with legislative and Commission requirements. Allowing PG&E to recover reasonable costs paid by it to comply with Commission and legislative requirement is fair and just."[48]
- D.94-10-059 – In discussing utility risk, the Commission stated, "Under traditional cost of service ratemaking, shareholders put up the initial capital for generation, transmission, distribution

[46] 18 CPUC2d 592, 599.

[47] 47 CPUC2d 143, 267.

[48] D.07-05-026 at 9.

and storage facilities, and are therefore exposed to potential investment losses if the project does not operate at all, or is removed from rate base because it goes out of service prematurely. However, as PG&E and SoCal explain . . . , under applicable PU Code sections, the Commission has the authority to allow utilities to recover close to the full investment costs of abandoned and out-of-service projects. For PG&E, there have been two proceedings relating to prematurely retired plant: Geysers Unit 15 and the Humboldt Bay Nuclear Power Plant. In each case, the Commission allowed PG&E to recover the undepreciated investments over five years with no return. Similarly, the Commission has also allowed SoCal to recover costs for gas transmission, distribution and storage projects that have never become used and useful, but not earn a rate of return on those investments."[49]

- D.92497 – The Commission stated, "We are concerned with the increasing magnitude of abandoned project costs and the frequency of abandonments, the cost of which we are routinely being asked to place on the ratepayers' shoulders. We are also concerned with the increasing burden being placed on the stockholders who in the past have invested in utility stocks as a reliable income stock with some growth possibilities and with very little risk. Although the costs in this case are small in comparison to some abandonment costs, such as those of Sundesert, this in itself is not sufficient justification for placing the entire burden either on the stockholder or the ratepayer . . . We cannot emphasize too strongly the necessity of examining each case on an individual basis to arrive at an equitable decision."[50]

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[49] 57 CPUC2d 1, 54.

[50] 4 CPUC2d 725, 777.

5.4. Positions to Deny Rate of Return on Retired Meters

Briefly, TURN's principal position and argument is that the retired meters are no longer used and useful, and the undepreciated or net plant balance should be denied a rate of return on such assets by excluding such balances from rate base.[51] TURN cites D.84-09-089 wherein the Commission stated:

> Over the years, this Commission has closely adhered to the "used and useful" principle, which requires that utility property be actually in use and providing service in order to be included in the utility's ratebase. We have regularly applied this principle to exclude from ratebase any construction work in progress, and have removed from ratebase plant which has ceased to be used and useful.[52]

As further support for its position, TURN cites D.85-08-046, regarding PG&E's Humboldt Unit 3, D.85-12-108 regarding SDG&E's Encina Unit 1 and other stored units, and D.92-12-057 regarding Geysers Unit 15. In each case the Commission amortized rate recovery of the net plant balances over either four or five years and excluded any rate of return on the unamortized balances.

In their reply briefs, both DRA and Aglet indicate support for TURN's recommendation.

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[51] TURN does not specify the mechanics of its recommendation with respect to how rate base should be adjusted. That is, how the undepreciated balance should be removed from rate base to exclude a commensurate rate of return and still accommodate calculation of depreciation expense that would provide recovery of that undepreciated balance over 18 years. However, the Settlement Agreement accomplishes this by leaving PG&E's undepreciated plant balance in rate base for calculation of both depreciation expense and rate of return and then backs out the rate of return element by reflecting a negative expense in the results of operations model.

[52] 16 CPUC2d 205, 228.

DRA's principal recommendation is to address this issue after PG&E has completed its SmartMeter deployment, now estimated to be in 2012. DRA also suggests other possibilities such as allowing PG&E to recover the cost of its remaining investment over the 18 years with a market based interest rate or possibly over a lesser number of years at some reasonable short-term interest rate.

Aglet states that PG&E's decision to retire its electromechanical meters before the end of their normal lifetimes has drastically changed the mortality characteristics of the asset group, but PG&E offers no evidence on the changed characteristics (that average asset life is reduced, and the dispersion from average mortality is substantial). According to Aglet, PG&E has not shown that reliance on group depreciation accounting is reasonable or justified.

With respect to public policy arguments, Aglet states that pursuit of new technology is insufficient cause to force customers to pay a rate of return on unused assets. Also, PG&E is asking the Commission to approve a rate of return on two meters for every customer, and approval of such ratemaking would be unfair to customers. For that reason, Aglet asserts PG&E's proposal would be poor public policy.

5.5. Positions Supporting Rate of Return for Retired Meters

PG&E, SCE and SDG&E oppose TURN's recommendation to exclude the net plant balance of the retired meters from rate base. Other than arguing that this issue has already been decided and should not be re-litigated, the utilities presented a number of arguments.

According to the utilities, PG&E's proposal to use group accounting is consistent with the Commission's Standard Practice U-4 (Determination of

Straight-Line Remaining Life Depreciation Accruals), financial accounting standards, and standard industry practice. Furthermore, PG&E and SCE assert that D.83-08-031 supports PG&E's proposal. In that decision, Pacific was allowed to reflect early retirements in rate base, for those assets where the early retirement was caused by economic trends (characterized as improvements in the state of the art or technological innovation). PG&E and SCE equate economic trends with the replacement of electric meters with the more advanced SmartMeters.

Both PG&E and SCE indicate that the utilities could have proposed alternative ratemaking for the retired meters to avoid the stranded costs, but the utilities explicitly chose not to do so in the AMI proceedings. Under group accounting utilities could have proposed to significantly reduce the recovery period to match the shortened lives, which would have recovered the investment so that the assets would be fully depreciated by the end of the deployment of the AMI meters. However, according to PG&E and SCE that was not proposed because of the impact it would have on rates. Instead, the utilities proposed to recover the remaining capital costs of the retired electromechanical meters in rate base over what would have been their remaining book lives had they not been replaced.

The utilities also characterize TURN's adjustment as being inconsistent with PG&E's SmartMeter decision, D.09-03-026, wherein the Commission addressed and quantified costs and benefits associated with the program. While TURN's recommendation results in less costs to ratepayers which is a benefit, that benefit was not identified in the SmartMeter proceeding analysis adopted by the Commission.

PG&E also states that TURN's recommendation is inconsistent with the Commission's evaluation of accelerated tax benefits in the SmartMeter Upgrade decision. PG&E argues D.09-03-026 reflected a deferred tax benefit for early retirement of the meters[53] and it would make no sense, and would be logically inconsistent, to expect that PG&E would provide a rate base reduction for an accelerated write-off of tax basis associated with retired meters when the underlying costs themselves would not be included in rate base. PG&E also argues that TURN's recommendation is in conflict with the Commission's generic investigation of taxes and ratemaking (OII 24) in that the OII established a matching principle in determining whether tax benefits should accrue to shareholders or ratepayers and found that, to the extent shareholders rather than customers fund a cost, shareholders should benefit.[54] Finally, PG&E indicates that, to the extent normalization rules of the Internal Revenue Code were to apply to these accelerated tax write-offs, TURN's proposal could well be in violation of these requirements by inconsistently treating costs and related tax benefits for ratemaking purposes.

The utilities also argue that the "used and useful" principle is not absolute, noting the PHFU exception as well as the uneconomic plant exception related to electric industry restructuring (D.97-11-074). Also noted was the ratemaking treatment for SONGS Unit 1 where the net plant balance of the retired plant was amortized over four years with a reduced rate of return on the unamortized

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53 The revenue requirement offset was computed by multiplying the incremental deferred tax resulting from meter retirement by a pre-tax rate of return.

54 *See* D.84-05-036, 15 CPUC2d 42, 47-49 and 52.

balance (D.92-08-036), and the ratemaking treatment for South Bay Unit 3 where the unit was put into PHFU (D.85-12-108).

PG&E also presents the argument that in past Commission decisions where no rate of return was allowed on unamortized amounts, the Commission was balancing shareholder and ratepayer interests, because there was a net burden caused by the early retirement or abandonment of the plants. That balance was achieved by allowing recovery of the direct costs over a shortened amortization period (shareholder benefit) but with no rate of return on any unamortized balances (ratepayer benefit). PG&E argues that in this instance, there is no net burden caused by the early retirement of the electric meters, rather there is a net benefit in that the Commission, in D.09-03-026, found the SmartMeter program to be cost-effective. Because there is no net burden associated with the SmartMeter program and the early retirement of the electric meters, PG&E asserts that there is no need for the Commission to address the allocation of net burdens using the "used and useful" principle. As support for this position PG&E cites D.84-05-100 regarding the abandonment of the Montezuma coal project which resulted in a net benefit to ratepayers. PG&E was compensated for all costs, including direct costs and accumulated carrying costs, with the remainder going to ratepayers.

PG&E also notes that TURN did not address why PG&E should not receive a rate of return for 18 years, which is inconsistent with prior Commission decisions where no rate of return was allowed but cost recovery was expedited, typically to four or five years.

The utilities also take the position that TURN's proposal should be rejected as a matter of public policy. PG&E indicates that the only reason the electromechanical meters are being taken out of service is that the Commission directed utilities such as PG&E to propose investments in AMI technology as a necessary predicate to demand response programs and other important public policies. So long as PG&E has not recovered its investment in those meters, PG&E will remain burdened by the continuing financing costs. PG&E states that it is only fair that shareholders should continue to recover their reasonable capital costs when property otherwise used and useful is replaced at the behest of the Commission, and for the Commission to adopt a different approach would be poor public policy and would discourage utilities from embracing technological change, even where warranted. SCE likewise states that investors can hardly be expected to fund innovations such as AMI technologies if doing so would result in denial of the expected return on their prior investments.

PG&E also asserts that it would be poor public policy for the Commission to encourage programs with one ratemaking assumption, but then adopt another once the program is implemented. PG&E states that the financial health of the utility and its customers depends on perceptions by investors that they will be treated fairly when they make long-run investments in the State's utilities, and adopting TURN's proposal, in light of the long record of AMI within the state, would diminish those perceptions of fairness and thus harm customers over the long run.

5.6. Discussion

No party argues that the electromechanical meters that are replaced by SmartMeters are used and useful. By PG&E's proposal the old meters are retired and excluded from plant in service and cannot in any way be considered used and useful. Also, there is no issue as to whether or not PG&E and its shareholders should receive rate recovery of the $341 million net plant balance, through depreciation expense or otherwise. Parties agree that PG&E should be allowed to recover that amount. The issue is whether the remaining net plant amounts should earn a rate of return as it is recovered over time.

The Commission has determined that plant which is not used and useful should be excluded from rate base (and therefore excluded from earning a rate of return). However, as a number of parties have noted, the Commission has also made exceptions to this general policy. In doing so, the causes, as well as the burdens and benefits of the plant items in question, have been taken into consideration in determining appropriate ratemaking balances and solutions. The particular circumstance of each situation has been, and must be, evaluated in making these determinations. There are a number of previous Commission decisions that relate to the issue at hand, and to the extent they are relevant to circumstances of this case, they will be used as a guide in resolving the issue.

We will grant rate of return treatment for the retired meters, despite the fact that they are no longer used and useful, due to our consideration of two facts. The first fact is that AMI implementation was encouraged by the Commission, as a means for implementing Commission demand side management policies. The second fact is that AMI implementation for PG&E, in the form of the SmartMeter Upgrade, was found by the Commission to be cost-effective. This reasoning is elaborated on below.

5.6.1. Cause

Costs can be stranded in a number of different ways, but when they become stranded due to Commission desires or actions that fact should be taken into consideration when determining appropriate ratemaking. For example, due to the Commission's implementation of electric restructuring, certain generation assets became stranded. Although no longer used and useful, in D.95-12-063, such assets were afforded rate base treatment as part of the overall electric restructuring ratemaking process. Also, in D.96-01-011, to address potential stranded costs related to SONGS 2 and 3, the Commission adopted the ICIP mechanism, which included the accelerated cost recovery of net plant assets with a rate of return on the unamortized balance. In none of the cases cited did the Commission specifically encourage or require a utility to prematurely retire an asset, or group of assets, that was functioning properly at the time. This is an important circumstance that differentiates the current proceeding from the cited precedents.

In granting rate base recovery for net plant associated with the shutdown of SONGS 1, the Commission stated:[55]

> "In light of the continued dispute over the future cost-effectiveness of operating SONGS 1, and the need to limit uncertainty for resource planning, the settlement agreement, which provides for the shutdown of SONGS 1 after the current fuel cycle and a return on the unamortized investment in SONGS 1 represents a reasonable compromise and should be adopted."

In that proceeding, the Commission's desire to shut down SONGS 1 in order to limit resource planning uncertainty was a stated reason for the Commission to allow rate base recovery of the stranded SONGS 1 assets.

The situation here, where the Commission encouraged deployment of AMI,[56] is more similar to the above cases where the Commission granted a return on plant that was not used and useful, rather than that in the cited examples where utilities were denied rate base treatment for plant that was never, or was no longer, used and useful (principally plant or project abandonments). In the

[55] D.92-08-036, 45 CPUC2d 274, 276.

[56] While AMI was encouraged by the Commission, the full replacement of existing electromechanical electric meters with SmartMeters was PG&E's own proposal.

cases where return on rate base was denied, the impetus for the non-used and useful status was utility actions rather than Commission desires or actions.

5.6.2. Cost-Effectiveness

As PG&E asserts, the fact that the SmartMeter program was determined to be cost effective is significant. Because of this determination, there is no net burden on ratepayers due to the early retirement of the electromechanical electric meters. This is opposed to the circumstances in many of the cited decisions where the Commission excluded plant that was not used and useful from rate base. In most of those cases there was a net burden on ratepayers because of the abandonment of a project or the shortened life of the project. In such cases the burden was shared by ratepayers (payment of the undepreciated balance over a shortened time period) and shareholders (no rate of return on the undepreciated balance, but over a shortened amortization period). In D.85-05-100, as cited by PG&E, the abandonment of the Montezuma project was a net benefit to ratepayers. PG&E was compensated for all costs, including direct costs and accumulated carrying costs, with the remainder going to ratepayers. Also in D.84-09-089, the Commission indicated that it has allowed the utility to rate-base a portion of the unamortized costs only when the residual value or potential benefits were likely to accrue to ratepayers.

5.6.3. Adopted Treatment

In considering the cause of the retired meters and the cost-effectiveness of the SmartMeters that replaced them, we are persuaded to grant a rate of return on the unamortized net plant balance of those retired meters. For this particular case, because the Commission encouraged AMI deployment and because the Commission has determined that the SmartMeter program is cost-effective and therefore would not impose a net burden for shareholders and ratepayers to share, it would be fair and reasonable to deviate from the general principle of excluding a rate of return on the net plant balance of assets that are no longer used and useful. This does not imply that it is necessarily fair and reasonable to adopt PG&E's proposal to amortize the net balance over 18 years with full rate of return recovery on the unamortized amounts. It must be remembered that the retired meters are not used and useful and this fact is important in considering the appropriate ratemaking for this issue. Use of Commission precedents, with respect to the length of the amortization period and the magnitude of the rate of return, would result in reduced ratepayer costs, as discussed below.

5.6.4. Amortization Period

Our reasoning and actions as discussed above do not alter the fact that ratepayers will be required to pay a substantial amount of money for the amortization of the undepreciated balance of plant that is no longer used and useful, as well as for a return on the unamortized balance of plant that is no longer used and useful. While this is a case where an exception to our general policy of excluding a rate of return on the unamortized balance of such plant is justified, it is also reasonable that this exception be implemented in a manner that is not only fair to shareholders but in a manner that minimizes ratepayer costs.

In the cases discussed above where a utility was either denied a rate of return or granted a rate of return, the amortization period was set at a reduced length of time, generally in the range of four to five years. To our knowledge, TURN's proposal to deny all return on the retired meters while maintaining the 18-year amortization schedule is without precedent. TURN does not cite any prior case in which the Commission denied all return on investment in prematurely retired long-lived assets without substantially shortening the amortization period. Indeed, due to inflation and the time value of money, forcing PG&E to wait 18 years to recover the $341 million balance in the retired meters at a zero percent rate of return would be tantamount to imposing a substantial penalty on PG&E shareholders.

The shortened recovery period minimizes, to an extent, the effect of granting or denying a rate of return. From a shareholder perspective, the shortened period accelerates recovery of funds on which they do not earn a return. From a ratepayer perspective, the shortened period reduces the total amount of return that will be incurred. It is appropriate to apply that same concept to this situation where ratepayers are responsible for a rate of return on the unamortized balance of plant that is no longer used and useful. We will set the amortization period at six years, or two GRC cycles, in order to reduce the total amount of return ratepayers will be required to pay. While the six-year amortization of $56,828,000 per year is more than the 18-year amortization of $18,943,000 per year contemplated by both TURN and PG&E, ratepayers will pay less for the rate of return component of PG&E's cost recovery. For example, at the currently authorized rate of return, the cumulative revenue requirement under the six-year amortization is approximately $480 million ($341 million in amortization expense and $139 million for rate of return)[57] as opposed to approximately $759 million under PG&E's proposal ($341 million in amortization expense and $418 million for rate of return).

Under the six-year amortization, PG&E will still receive full recovery of the December 31, 2010 undepreciated electromechanical meter plant balance and

[57] The rate of return number also includes associated taxes, uncollectibles and franchise fees.

a rate of return on the unamortized amounts. However, as discussed below, we believe that the applicable rate of return should be adjusted consistent with previous Commission decisions where rates of return were reduced commensurate with reduced shareholder risks.

5.6.5. Rate of Return

In most of the cases cited in testimony and briefs, the utilities either did not receive a rate of return on the undepreciated balance; or, if a rate of return was authorized, the rate was reduced such that the return on equity was equal to the embedded cost of debt or 90% of the embedded cost of debt.

PG&E and SCE reference D.83-08-031 to support PG&E's position, the only case cited in which a utility was permitted to continue earning a full rate of return on plant that was no longer used and useful. However, as discussed below, due to the specific circumstances in that case, we are not convinced that D.83-08-031 is an appropriate precedent.

SDG&E indicates that the lower rate of return in the restructuring decision (D.95-12-063) should not apply to PG&E, stating:

> It should be noted that the CPUC provided a lower rate of return in the restructuring decision in order to provide utilities with an incentive to divest fossil-fueled generation assets. No such incentive is applicable to retired meters. Furthermore the CPUC stated that the reduced return reflected reduced risk associated with these assets "as we accelerate the return of their net book value through the CTC recovery." In contrast here, the recovery period for retired meters is not accelerated, and while the Commission established a non-bypassable charge to recover transition costs, no equivalent mechanism exists with respect to retired meters.[58]

[58] SDG&E Reply Brief at 4, footnote 3.

While it is true that there is no incentive available for PG&E to raise the rate of return similar to that provided in the restructuring decision, the more important considerations are that by this decision, PG&E will have accelerated recovery of the net book value over six, rather than 18 years, and, while there is no non-bypassable charge, there is no risk associated with the recovery of the remaining net book value. As the Commission stated, regarding cost of capital and related regulatory risk:[59]

> Regulatory risk pertains to new risks that investors may face from future regulatory actions that we, and other regulatory agencies, might take. Examples include the potential disallowance of operating expenses and rate base additions, comparability of utility ROEs throughout the United States and rating agencies' outlooks for the California regulatory environment.

By this decision, such regulatory risk is minimized if not eliminated. There is certainty with respect to cost recovery and that cost recovery will occur over a shorter period than originally anticipated.

This case presents a unique set of circumstances compared to the previous cases. In cases in which the utility was denied any rate of return, the plant in question had become inoperable either due to order of a federal regulatory agency (Humboldt Bay)[60] or due to a misestimation of the available energy resource (Geysers Unit 15). Where the utility was granted a return on equity at or below the cost of debt, concerns existed about the plant's ability to continue operating cost-effectively (SONGS 1) or the possibility that utilities would face

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[59] D.07-12-049 at 31.

[60] In the case of Humboldt Bay, the Nuclear Regulatory Commission prohibited operation of the facility due to concerns about the plant's ability to operate safely in light of faults discovered after the plant's construction. See 18 CPUC 2d, 593.

stranded costs for plants that may not have been competitive in a restructured market. With respect to recovery of potential stranded costs due to restructuring, the Commission stated:

> We note that we are not required to guarantee full transition cost recovery. We are required only to design a rate structure the total impact of which provides the utilities with the opportunity to earn a fair return on their investment. [citation omitted] We are allowing the utilities the opportunity to recover generation plant-based transition costs and providing an appropriate risk-based rate of return until those costs are recovered.[61]

In the current case, there is no concern or uncertainty that the assets in question may be uneconomic due to competitive pressures. Rather, PG&E has been encouraged to definitively retire assets that would have otherwise remained used and useful and on which it would have continued to earn a full rate of return. We do not wish to discourage utilities from replacing their existing assets with new technologies under these circumstances, especially when we have found the replacement to be cost-effective for customers. We are concerned that if we reduced utility returns on the replaced assets below the rate of return on debt, the reduced return would send the wrong signal to investors who may wish to consider future technological replacements that could better serve customers. Normally, equity investors receive the opportunity to earn a return above debt returns because equity investments face higher risk.

Offsetting this consideration are two factors. As discussed above, the reduced amortization period reduces the risk of recovering the capital invested in these assets. The other factor is fairness to ratepayers. As Aglet argued,

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[61] 64 CPUC2d, 61 – 62.

"PG&E is asking the Commission to approve a rate of return on two meters for every customer."[62] In balancing the considerations of reduced risk to PG&E of recovering shareholder investment, the interest of the ratepayers who are now paying a full rate of return on the new SmartMeters, and the cause of the early retirement of the electromechanical meters, we will authorize a return on equity of 6.55% for the electromechanical meters. This yields an overall after tax return of 6.3%.

5.6.6. The Use of Group Accounting

The utilities argue that PG&E's proposal to use group accounting principles is proper and consistent with Commission Standard Practice U-4 (Determination of Straight-Line Remaining Life Depreciation Accruals) and standard industry practice. PG&E and SCE also note that, in the case of the electromechanical meters, under group accounting utilities could have proposed to significantly reduce the recovery period to match the shortened lives. The shorter remaining lives would have recovered the investment so that the assets would be fully depreciated by the end of the deployment of the AMI meters. However, this was not proposed by either PG&E or SCE because of the impact it would have on rates. Instead, PG&E and SCE have proposed to recover the remaining capital costs of the retired electromechanical meters in rate base over what would have been their remaining book lives had they not been replaced.

The Commission's general approval of the use of group accounting principles reflects the fact that, over time, the undepreciated balances of premature plant retirements have been retained in rate base exactly as proposed

[62] Aglet Reply Brief at 4.

by PG&E for meter devices replaced by SmartMeters, although on a much smaller scale. However, the effect of retaining those smaller balances in rate base has been offset, at least to a large degree, by plant assets that exceed their expected lives. That is not the case here where meters are being retired early, on a wholesale basis, with significant financial consequences that are not balanced out over time. Because of this, it is appropriate that the Commission should critically review the use of group accounting and alternatives, for this particular circumstance.

We agree that PG&E could have alternatively shortened the expected lives of the meters, on a prospective basis, in calculating depreciation rates. However, they did not, and even if they had, the question of appropriate ratemaking for a large amount of prematurely retired plant would need to be analyzed in the same way as was done in this decision for PG&E's proposal.

5.6.7. D.83-08-031

We note PG&E and SCE reference D.83-08-031 and assert that it supports PG&E's proposal. However, we are reluctant to use this case as a precedent to justify PG&E's proposal. In that case, it was determined that Pacific's migration strategy and technological change were principally responsible for a depreciation reserve shortage and the need to increase depreciation rates. While it is true that the decision only excluded migration costs from rate base and recovery from ratepayers, and did not exclude costs due to technological change, it is not clear what the effect of technological change was in this particular circumstance. Estimates of the amount of stranded investment on Pacific's books at that time ranged from $19 to $95.7 million (D.83-08-031, Finding of Fact 12). Also, the amount associated with the migration strategy was $19 million (Finding of Fact 13). Thus, the amount of remaining stranded costs (as low as zero to as much as

$77 million) may not have been of significant magnitude to justify the need to consider alternatives to balance any shareholder/ratepayers risks associated with stranded plant, especially in light of the fact there were certain cost reductions due to the exclusion of migration strategy related plant in its entirety. The circumstances were also different in that the Commission provided that the remaining stranded amount, if any, and any future amounts caused by the shortening of the expected lives of plant assets would be recovered by the straight line remaining life method for calculating depreciation by evaluating the expected lives on a frequent, possibly annual, basis.[63] In that way there would be no stranded costs as shown in the examples that were included in Appendix A to that decision. That is, the amount of plant that is not used and useful for possibly a number of different plant assets would be minimized, or eliminated, by adjusting the estimated service lives on an ongoing basis.[64] That is not the case with respect to PG&E's proposal where a large amount of undepreciated plant for a particular asset will no longer be used and useful and will be amortized over a lengthy period of time.

Also, the difference in industry (telecommunications versus electric) may be a reason to differentiate how this issue is treated, because the depreciable lives of telecommunications equipment appear to be shorter than that for the electric industry. In the D.83-08-031 Appendix A examples, assumed lives in the range of four to six years are used, as opposed to the 18 years associated with the electric meters. In general, since the lives are relatively short to start with,

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[63] 12 CPUC2d 150, 167-168.

[64] This is similar to what PG&E and SCE indicated they could have done, but did not do.

adjustments to the estimated service lives would not be as significant as they would be if, for instance, PG&E had prospectively reduced the estimated life for the electromechanical meters from 18 years to, for example, four years. With the shorter lives in the telecommunications industry, the long term affect of ratepayer funding of return costs on undepreciated balances is minimized when compared to the electric industry and specifically to the electric meters at issue here. For example, in this case, the ratepayer costs associated with the rate of return on the undepreciated meter balance amounts to approximately $420 million over 18 years as opposed to approximately $140 million if it were amortized over 6 years.

To summarize, the circumstances related to the Pacific case are not the same as that of PG&E. The decision resolves the Pacific issue in a manner that would result in little or no net plant balances being associated with plant that is retired. That is because the estimated lives of the assets would be evaluated and adjusted on an ongoing basis so that the assumed and actual lives are balanced out. This result is directly opposed to the issue being addressed now for PG&E, which is what to do with the significant net plant balance associated with meters that are no longer used and useful. Also, it is not clear that significant net costs were imposed on ratepayers as a result of the Pacific decision.

5.6.8. Public Policy

With respect to comments related to public policy, the decision on this issue is sufficiently different from the TURN proposal to mitigate most of the concerns. By analyzing this issue, resolving it in a manner consistent with prior Commission decisions and resolving it in a manner that minimizes total ratepayer costs, public policy considerations are enhanced, not diminished. It would be poor public policy to include large amounts of plant that is not used and useful in rate base without a full analysis and consideration of the specific facts and circumstances. Even if it is determined to be appropriate to retain such assets in rate base, it would be poor public policy to not minimize the costs to ratepayers to the extent possible, because ratepayers are no longer getting any use of that plant.

5.6.9. SmartMeter Cost/Benefit Analysis

We note the utilities' argument that the SmartMeter Upgrade proceeding did not take into consideration the additional benefits associated with a different methodology for handling the undepreciated plant balance associated with retired electromechanical electric meters. PG&E states that the Commission's weighing of costs and benefits for the AMI project clearly did not include the rate base benefit associated with removing the electromechanical meters from rate base. We do not see this fact as a reason to be concerned with taking up the issue at this time or deciding it in the manner that we do. In the SmartMeter Upgrade proceeding, the Commission determined that PG&E's proposal was marginally cost-effective.[65] Despite this, the Commission authorized the program. It did so for a number of reasons including that, "It is likely that there are other benefits that have not been quantified by PG&E . . . "[66] That there now actually may be additional benefits only substantiates the Commission's decision to approve PG&E's SmartMeter program in the first place. It does not unfairly disadvantage PG&E. We would not change any of the outcomes, conditions or requirements

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65 D.09-03-026 at 153.

66 D.09-03-026 at 154.

of D.09-03-026 based on the identification of additional benefits that justify the program.

5.6.10. Standard of Proof

TURN and DRA both assert that PG&E has not met its burden of proof by providing "clear and convincing" evidence to demonstrate the reasonableness of its proposal. We do not agree.

First, we do not agree that clear and convincing is the appropriate standard of proof for GRC matters. As noted by both TURN and DRA, in D.09-03-025 the Commission addressed the "preponderance of evidence" and "clear and convincing" standards of proof, stating:[67]

> With the burden of proof placed on the applicant in rate cases, the Commission has held that the standard of proof the applicant must meet is that of a preponderance of evidence, which the Commission has, at times, incorrectly referred to as "clear and convincing" evidence. Evidence Code § 190 defines "proof" as the establishment by evidence of "a requisite degree of belief." We have analyzed the record in this proceeding within these parameters.

In that decision, the Commission determined that for resolving GRC matters the "requisite degree of belief" can be established with the "preponderance of evidence" standard. The Commission also indicated that this standard was incorrectly referred to as "clear and convincing" in a number of previous decisions. TURN and DRA indicate that the clear and convincing standard should be affirmed. However, by principally citing previous decisions where the term "clear and convincing" was used and where the Commission has since stated that such characterization was incorrect, TURN and DRA have not

[67] D.09-03-025 at 22 (footnotes omitted).

provided sufficient reason for reversing the latest decision on this matter.[68] Also, the Commission's determinations in D.09-03-025 are consistent with California Evidence Code, Section 115, which states:

> "Burden of proof" means the obligation of a party to establish by evidence a requisite degree of belief concerning a fact in the mind of the trier of fact or the court. The burden of proof may require a party to raise a reasonable doubt concerning the existence or nonexistence of a fact or that he establish the existence or nonexistence of a fact by a preponderance of the evidence, by clear and convincing proof, or by proof beyond a reasonable doubt. **Except as otherwise provided by law, the burden of proof requires proof by a preponderance of the evidence.** (emphasis added.)

Second, and more importantly, as previously discussed, PG&E's proposal for retired electromechanical meters was made in the prior AMI proceedings. The proposal was laid out in testimony, was not opposed, and is reflected in the current ratemaking treatment for the SmartMeter program. Subsequent to being reflected in adopted ratemaking treatment and calculations, we do not expect that a utility should reestablish the reasonableness of that element or any other of the number of already approved elements used in the revenue requirement calculations each and every time those calculations are used. That PG&E did not do so with respect to the retired meter issue is consistent with our expectations. That PG&E demonstrated that its proposed treatment of the meters is consistent with the Commission's decisions in its AMI proceedings is sufficient with respect to meeting its initial burden of proof. However, providing such evidence does not necessarily ensure adoption or use of the proposal going forward. Certainly, elements of the revenue requirement calculation can be questioned in subsequent

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68 We note that neither DRA nor TURN sought to appeal D.09-03-025 with respect to

Footnote continued on next page

proceedings, just as PG&E's retired meter proposal was in this proceeding, and modified, if necessary, just as the Commission has done in this instance.

5.6.11. Other Arguments

TURN suggests that an alternative to removing the meter investment from rate base would be for the Commission to direct PG&E to pursue securitization of the remaining meter investment. According to TURN this would produce ratepayer savings by achieving lower cost of financing than rate base recovery and would be similar to the financing used on the Ratepayer Reduction Bonds under Assembly Bill 1890 and PG&E's bankruptcy. TURN adds it may well require legislation as was the case for the two examples. DRA also suggested that PG&E be allowed to recover the cost of its remaining investment over the 18 years with a market based interest rate or possibly over a lesser number of years at some reasonable short-term interest rate.

It appears legislation would be required to implement securitization as alternatively recommended by TURN. There is no certainty as to when, or even if, such legislation would be undertaken and finalized. Also, with respect to DRA's suggestions, there is no record as to what an appropriate level would be for a market based rate or a short-term interest rate and why it would be appropriate to use either rate in addressing the particular circumstances of this issue.

With respect to PG&E's arguments regarding inconsistent ratemaking and tax treatments associated with the accelerated tax benefit that is reflected in the SmartMeter decision, we do not believe these arguments apply to our resolution

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this matter.

of the meter retirement issue in this decision because, rather than zero rate of return as recommended by TURN, a rate of return on the undepreciated meter balance is being authorized.

With respect to Aglet's argument regarding the changed mortality characteristics of the electromechanical meters, we agree that expected lives for meters that are being retired prematurely are much different than the new meters that are being installed. However, it is not clear how that fact would change any of the determinations made in this decision regarding the retired meter issue. If Aglet is asserting that the estimated remaining life of this asset group needs to be reevaluated, that may or may not be the case. DRA and PG&E have settled on the depreciation rate for meters, and neither party had an opportunity to respond to Aglet's concern, since it was expressed in Aglet's reply brief. If necessary, this can be explored in PG&E's next GRC.

5.6.12. Adopted Results

Use of the six-year amortization and the reduced overall rate of return from 8.79% to 6.3% results in a revenue requirement of approximately $85.4 million in 2011, $80.2 million in 2012, $75.0 million in 2013, $69.8 million in 2014, $64.6 million in 2015, and $59.4 million in 2013. An alternative calculation would result in 6 equal amounts of $74.0 million/year for each of the years 2011 through 2016. With respect to this issue and how it affects the Settlement Agreement attrition allowances for 2012 and 2013, it appears that the Settling Parties agreed that the attrition increases remain fixed irrespective of how the meter retirement issue is resolved. This is consistent with the adoption of TURN's position on this issue since the associated revenue requirement would not change year to year. However, if PG&E's position were adopted the revenue requirement associated with the meter issue should decline year to year due to the amortization of the undepreciated balance over time. It would not do so under the Settlement Agreement. Therefore, rather than adopting declining revenue requirements associated with the meter issue and imposing attrition increases that are different from what is included in the Settlement Agreement, the levelized cost of $74.0 million will be used for each of the years.[69] The authorized attrition increases will then be consistent with the Settlement Agreement, while correctly reflecting the adopted results of this decision with respect to the retired meter issue.

For 2011, the decision amount is $55.1 million higher than TURN's recommendation of $18.9 million and $11.1 million higher than PG&E's request of $62.9 million. However, the amortization period will be 12 years shorter than that proposed by both PG&E and TURN. By this decision, total costs to ratepayers over six years will amount to $444 million. This is $315 million less than PG&E's 18-year amortization request of $759 million. Even though the ratepayers will be paying more money upfront and there is a time value of money impact, the ratepayers should be better off by this decision as opposed to PG&E's proposal. While the decision will result in $103 million more in ratepayer costs when compared to TURN's 18-year amortization proposal, we

[69] By this method, the amortization schedule for the $341 million amount associated with undepreciated electromechanical meters replaced by SmartMeters will be as follows: $44.7 million for 2011, $49.0 million for 2012, $53.7 million for 2013, $58.8 million for 2014, $64.4 million for 2015, and $70.5 million for 2016. These amounts include the original amortization of $18.9 million per year for these meters.

have determined that, for the circumstances of this case, TURN's proposal should not be adopted.[70]

Due to the manner in which this issue has been resolved, the authorized revenue requirement increase for test year 2011 will be $237 million (7.9%) for electric distribution, as opposed to the $183 million (6.1%) increase reflected in the Settlement Agreement. The total test year 2011 increase for electric distribution, gas distribution and electric generation is $450 million (8.1%), as opposed to the $395 million ($7.1%) increase reflected in the Settlement Agreement. Tables related to the Settlement Agreement that change as a result of the decision on this issue are included in Attachment 3 (Changes to Appendix A of the Settlement Agreement) and Attachment 4 (Changes to the Results of Operations Tables).

For the 2011-2013 GRC period, the cumulative increase authorized by this decision is $1.9 billion, which is still significantly less than the $4.0 billion amount requested by PG&E and discussed in Section 4.7.2 of this decision. When considering the long-term ratepayer benefit of amortizing the undepreciated net plant balance for the retired meters over an accelerated time period and reduced rate of return when compared to PG&E's proposal, our determination that, when looked at in total, the Settlement Agreement produces a reasonable outcome holds for the increases authorized by this decision.

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[70] For comparison purposes, the present value (PV) cost of the different alternatives was calculated using a conservative discount rate of 10%. For the adopted result, the PV cost is approximately $312 million. For PG&E's proposal, the PV cost is approximately $375 million. For TURN's proposal, the PV cost is approximately $145 million. If TURN's proposal were modified to amortize the balance over six, rather than 18 years, the PV would be approximately $240 million.

Consistent with the Settlement Agreement premise that the attrition allowances for 2012 and 2013 are fixed, the amortization amounts for 2012 and 2013 are similarly fixed irrespective of any changes to the authorized cost of capital during that timeframe.

In PG&E's next GRC, for the remaining three years of the amortization, parties may present recommendations to change the amortization amount to reflect an updated authorized rate of return or the use of a declining rather than levelized amortization expense.

6. Comments on Proposed Decision

The proposed decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 14, 2010 by WEM, PG&E, DRA, Greenlining, SCE, SDG&E, and Aglet. One set of joint comments was filed by Aglet, DRA, DACC, TURN, and WEM and another set, pertaining to the non-tariffed products and services issues, was filed by DRA, PG&E and TURN. Reply comments were filed on March 21, 2010 by Aglet, TURN, SCE, PG&E, SDG&E, DRA, and Greenlining. To the extent that the comments merely reargued the parties' positions taken in briefs, those comments have not been given any weight. The comments that focused on factual, legal or technical errors have been considered, and, if appropriate, changes have been made.

In its comments, Greenlining requested an opportunity for final oral argument in this proceeding. Greenlining's request is denied. The request is inconsistent with the requirements for presenting such argument, as detailed in the March 5, 2010 Scoping Memo.[71] Also, the retired meter issue, the only issue not settled, was thoroughly briefed by a number of parties.[72] A final oral argument is not necessary.

6.1. Revenue Requirement Calculations

In comments, PG&E and Aglet proposed revisions to the calculations of the return on the electromechanical meters if either the ALJ proposed decision or the Assigned Commissioner's alternate proposed decision were adopted.

PG&E proposes that the revenue requirement for the amortization of the retired meters over six years be increased for three reasons:

(1) The incremental capital recovery triggers additional California income tax expense. PG&E state this is because California income tax is computed on a "flow through" basis, meaning tax expense for ratemaking purposes matches the taxes the utility expects to pay based on the State tax code. In the early years of an asset's life, the benefits of accelerated State tax depreciation are used dollar for dollar to reduce the forecast of State income tax for ratemaking purposes. Conversely, in the later years of an asset's life, the recovery of the cost of the asset triggers revenues that exceed available tax deductions, resulting in additional tax expense.

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[71] The Scoping Memo states that any party seeking to present a final oral argument should have filed and served a motion within 10 days of the filing date of reply briefs. Such motion should have stated the request, the subjects to be addressed, the amount of time requested, any recommended procedure and order of presentations, and all other relevant matters, so that the Commission would have all the information necessary to make an informed ruling on the motion and to provide an efficient, fair, equitable, and reasonable final oral argument. Greenlining did not file such a motion or provide the required information in its proposed decision comment request.

[72] It is also noted that that Commissioner Sandoval and Commissioner Ferron held an All-Party Meeting on April 20, 2011 regarding the ALJ proposed decision and Commissioner Peevey's alternate proposed decision.

(2) The incremental capital recovery also triggers additional federal income tax that is reflected for ratemaking purposes as an increase to rate base. PG&E states that additional federal income taxes are reflected under standard ratemaking practice as a reduction to deferred taxes (increase to rate base).

(3) To be consistent with the Settlement Agreement, PG&E's rate base should be reduced in the attrition years so as to reflect only the incremental capital recovery amount as a result of the incremental amortization above the originally envisioned 18-year amortization. PG&E states the technical adjustments impact the attrition years and result in PG&E continuing to earn a return on an additional 1/18th of the retired meter investment in attrition year 2012 and an additional 2/18th of retired meter investment in attrition year 2013.

PG&E requests that it be allowed to file a Tier 2 advice letter that sets forth additional revenue requirements for this GRC on a levelized basis consistent with the discussion in this decision, with the provision that in no event shall such additional revenue requirements exceed $15 million for this GRC cycle. Such additional revenue requirements would become effective when approved, retroactive to January 1, 2011.

PG&E does not explain the accounting for the remaining state tax depreciation that has not yet been used. Specifically, it is not clear why those amounts should not be used to offset a portion of the additional state tax liability over the six-year amortization period. Also, it is not clear whether the additional state taxes can be used as additional federal tax deductions. With respect to the federal tax related rate base increase, it is not clear whether, or how, remaining accelerated and book depreciation amounts are being used to offset the increase related to the additional amortization over the six-year period.

In reply comments, DRA and TURN took the position that the additional revenue requirements requested by PG&E should not be allowed because none of the information used by PG&E is part of the record. We disagree with respect to income tax calculations. Income tax calculations and all the information that supports such calculations are embedded in the results of operations model that is used for calculating the GRC revenue requirements. While the Commission decided to amortize the net plant associated with retired meters over six years, the associated revenue requirements were not calculated using a completely revised results of operations model. If they had been, the income tax adjustments proposed by PG&E would, at least to some extent, have been reflected in the authorized revenue requirements generated by the model. It is therefore reasonable to adjust the revenue requirements accordingly. PG&E may file a compliance advice letter that sets forth the annual amortization schedule base on the reduced rate of return. This amortization schedule should then be used to determine any incremental recovery amounts related to state and federal income taxes, to the extent the information is a part of the results of operations data base for this proceeding and is consistent with the manner in which the results of operations model calculates revenue requirements.

In calculating the associated revenue requirements for the compliance advice letter filing, PG&E should, to the extent possible, reflect any remaining state tax depreciation and federal tax and book depreciation as deductions over the six year amortization period; to the extent applicable, reflect any increased state taxes as increased deductions for calculating federal income taxes; and reflect any other standard ratemaking adjustments that would lower the revenue requirements.

We do not agree with PG&E's adjustment related to the rate base for the attrition years. The Settlement Agreement fixed the attrition year rate increases, not the rate base. By the Settlement Agreement, the attrition year revenue requirement increases are not tied to the outcome of the retired meter issue. Whether TURN or PG&E had prevailed on this issue, the attrition year increases would have been as specified in the Settlement Agreement. We choose to maintain that same outcome here. That is, even though the resolution of the issue does not comport with the recommendation of either PG&E or TURN, the attrition year increases should still be the same as specified in the Settlement Agreement.

In its comments, Aglet states that the levelized cost calculations are simple but incorrect, because they grant PG&E the chosen rate of return on retired meters and on deferred revenue requirements. According to Aglet, under conventional ratemaking, without the levelization procedure, PG&E would record in a balancing account (1) authorized revenue requirements as a debit, (2) associated revenues as a credit, and (3) short-term interest on the account balance. Aglet recommends amending that procedure to allow PG&E to earn balancing account interest on the undercollection. Balancing account interest rates are short-term commercial paper rates, which are substantially lower than PG&E's overall rate of return. Aglet proposes that this be accomplished by (a) creating a new Retired Meter Balancing Account, (b) authorizing monthly debits equal to capital-related revenue requirements (depreciation, rate of return at the chosen rate of return, incremental income taxes, franchise fees and uncollectibles) on the undepreciated plant balance, (c) authorizing credits equal to incremental revenues, and (d) authorizing interest at short-term commercial paper rates. Aglet states that the new accounts would look much like existing balancing accounts for PG&E's base rate revenue requirements, which allow only short-term commercial paper rates on account undercollections.

While Aglet's proposal is a Commission-approved method for treating undercollections and overcollections in balancing accounts, it is not appropriate for our purpose here, which is merely to create a levelized annual revenue requirement for the six-year amortization of the retired meter balance. The consequences of Aglet's proposal run contrary to the mortgage-style recovery where the revenue requirement is levelized with more of the revenue going to return in the early years and less going to return in the later years, but all return is on unamortized plant, not on deferred revenues. We will not adopt Aglet's recommendation.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and David K. Fukutome is the assigned ALJ in this proceeding.

Findings of Fact

1. The Settlement Agreement is unopposed.

2. The Settlement Agreement was signed by 17 of the 20 active parties in this proceeding. The Settling Parties represent a variety of interests other than that of PG&E.

3. The record in this proceeding supports reductions to PG&E's request but not to the full extent advocated during this proceeding by the various other parties.

4. The fact that a large number of parties with diverse interests and recommendations were able to reach a compromise that is acceptable from their various viewpoints provides assurance that the overall result of the Settlement Agreement is reasonable.

5. Aside from the effects of the one issue that was not resolved, the test year 2011 revenue requirements for electric distribution, gas distribution, and electric

generation, as depicted in the Settlement Agreement, are consistent with the record and reasonable.

6. The 2012 and 2013 attrition increases for electric distribution, gas distribution, and electric generation, as depicted in the Settlement Agreement, are consistent with the record and reasonable.

7. The Settlement Agreement also includes a number of guidelines and directions that are consistent with the record and reasonable, and address:

- Retention of the Vegetation Management Balancing Account.
- Allocation of work credits for Rule 20A projects.
- Allocation of electric RD&D project costs between generation and distribution, and, with certain limitations, placement of project results in the public domain.
- Establishment of the Distribution Integrity Management Program and an associated one-way balancing account.
- Treatment of the postretirement benefits other than pensions and long term disability balancing account and associated costs.
- Treatment of certain Diablo Canyon Power Plant labor costs as operating expense rather than capital expenditures.
- Cost recovery treatment and guidelines related to the Diablo Canyon Steam Generator Replacement Project, Gateway Settlement Balancing Account, Colusa Generating Station, Humboldt Bay generating station, Hunters Point Power Plant site, and nuclear fuel payments.
- Below-the-line treatment of customer retention costs incurred by the Customer Care organization.
- Requiring an independent audit of PG&E's SmartMeter-related costs.
- Continuation of the SmartMeter Benefits Realization Mechanism.
- Treatment of the Commission's consultant costs for the SmartMeter evaluation as an eligible cost in the SmartMeter balancing accounts.

- Commitment of PG&E to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA fees.
- Rejection of reconnection fee adjustments.
- Approval of 8:30 a.m. to 5:00 p.m. as local office hours.
- Reduction of Non-sufficient Funds Fee to $9 from the current level of $11.50.
- Modification of PG&E's Below-the-Line Guidelines.
- Treatment of employee transfers from affiliates.
- Guidelines for meal expense records.
- Recovery of nuclear fuel and fuel oil carrying costs at short-term commercial paper rates.
- Removal of all Market Redesign and Technology Upgrade related revenue requirements from this proceeding.
- Denial of PG&E's requests for new balancing accounts for health care costs, New Business/WRO/Rule 20 renewable energy projects, uncollectibles, emergencies and catastrophic events, and RD&D expenses.
- Use of the adopted 2011 rate base amounts in developing revenue requirements from future cost of capital proceedings.
- Use of adopted 2011 administrative and general expenses for use in determining administrative and general expenses in related proceedings, if needed.
- Approval of the Memorandum of Understanding between DisabRA and PG&E.
- Elimination of the requirement for PG&E to prepare total factor productivity studies.
- Elimination of the requirement for PG&E to include information about long-term incentives that are not funded by ratepayers, in future total compensation studies.
- Review of the Results of Operations model for use in PG&E's next GRC.
- Justification of new types of costs in the next GRC.

- Suspension of Allowance for Funds Used During Construction accruals for the ten Transform Operations projects identified by TURN.
- Employee training and hiring testimony requirements for PG&E in its next GRC.

8. An annual information-only report with the information described herein that is submitted by PG&E to the Energy Division and interested parties will allow the Commission and parties to monitor PG&E's expansion of NTP&S into areas already being offered by the other major energy utilities.

9. PG&E's experience for the current advice letter approval process for new NTP&S is eight months to one year for approval.

10. A reprioritization process is expected and is necessary for the utility to manage its operations in a safe and reliable manner.

11. Despite any financial implications of exceeding authorized cost levels, the utility has the responsibility to spend what is necessary to ensure safe and reliable service.

12. Reprioritization and cost deferrals undermine the basis for the Commission's determination of the reasonableness of the utility's GRC request and the extent of the authorized revenue requirement.

13. Reprioritized needs and associated costs may not result in the most efficient use of funds.

14. Due to the Commission's responsibilities and concerns regarding gas pipeline safety there is a need for additional reporting requirements related to gas distribution pipelines.

15. PG&E is financially healthy and has very strong access to capital because of its strong balance sheet and its ability to raise capital from both equity and debt financing.

16. For the period covered by this GRC, the Settlement Agreement will provide PG&E with sufficient revenues to maintain its financial health, provide adequate service, and make necessary capital investments.

17. The Settlement Agreement advances the public interest because it sets forth a compromise that significantly reduces the revenue sought by PG&E while providing PG&E a test year revenue requirement increase and predictable attrition allowance.

18. The Settlement Agreement furthers the public interest (such as safe and reliable service, ratepayer safeguards, and levelized competitive playing fields) by:

- Retaining the current one-way Vegetation Management Balancing Account, whereby any unspent amount will be returned to ratepayers.
- Allowing communities with Rule 20 undergrounding projects already in progress to continue with their projects even if they exceed the 5-year allowable borrowing period.
- Establishing a one-way balancing account mechanism for the gas related Distribution Integrity Management Program that covers developments and improvements in such areas as preventative maintenance, leak surveys, operator qualifications and training. Any net unspent funds from this program will be returned to customers in the next GRC.
- Allowing PG&E to file a subsequent application to recover additional site-specific environmental remediation costs to the extent necessary to accommodate the development plan ultimately adopted for the Hunters Point site.
- Requiring PG&E to record customer retention costs incurred by its Customer Care organization below-the-line.
- Committing PG&E to file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA service fees.

- Modifying PG&E's below-the-line guidelines to provide for an annual compliance review, as well as identification of additional below-the-line activities and more thorough accounting and employee training.
- Advocating Commission approval of the MOU between PG&E and DisabRA regarding accessibility and safety issues for the disabled.
- Providing for an independent audit, at PG&E's expense, to ensure proper booking and allocation of costs and benefits related to PG&E's SmartMeter program and 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 account.

19. The Commission encouraged the electric utilities, including PG&E, to consider and implement AMI. PG&E responded with an initial AMI proposal in June 2005 (A.05-06-028) and a revised proposal in December 2007 (A.07-12-009).

20. In both A.05-06-028 and A.07-12-009, PG&E proposed to reduce both the electric plant in service balance and the depreciation reserve balance by the original cost of the electromechanical electric meters that are replaced by SmartMeters. This produces a result that is the same as leaving the retired meters in plant, continuing depreciation over the estimated life of that asset and receiving a rate of return on the undepreciated balance.

21. No party addressed PG&E's retired meter proposal in either A.05-06-028 or A.07-12-009.

22. Neither D.06-07-028 nor D.09-03-026 contains specific discussion of PG&E's ratemaking proposal for retired meters or includes findings, conclusions or ordering paragraphs in which this issue is specifically identified.

23. Neither the magnitude of the net plant balance for prematurely retired meters, nor the associated rate of return costs were identified in PG&E's prior AMI testimony.

24. With respect to the retired meter issue, parties have made a number of arguments and cited precedential Commission actions that are relevant and significant, but which were never brought up and considered in the prior AMI proceedings.

25. In D.09-03-026, the Commission found PG&E's SmartMeter Upgrade proposal to be cost-effective, in that estimated incremental benefits are expected to exceed incremental estimated costs.

26. Electromechanical electric meters replaced by SmartMeters are no longer used and useful.

27. While the Commission has determined that plant which is not used and useful should be excluded from rate base (and therefore excluded from earning a rate of return), the Commission has also made exceptions to this general policy.

28. There are Commission precedents for denying or reducing the rate of return associated with plant that is not, or is no longer, used and useful.

29. There are Commission precedents for the accelerated cost recovery of plant that is not, or is no longer, used and useful.

30. While the Commission decided to amortize the net plant associated with retired meters over six years, in the ALJ proposed decision and the assigned Commissioner alternate proposed decision, the associated revenue requirements were not calculated using a completely revised results of operations model.

31. The circumstances related to the issues resolved in D.83-08-031 are not the same as those related to the retired meter issue in this proceeding.

32. Any additional implicit SmartMeter benefits due to the Commission's resolution of the retired meter issue in this proceeding further substantiates the Commission's decision to approve PG&E's SmartMeter program that was

determined to be marginally cost-effective at that time. That there may be additional benefits does not disadvantage PG&E.

33. That PG&E demonstrated that its proposed treatment of the meters is consistent with the Commission's decisions in its AMI proceedings is sufficient for meeting its initial burden of proof with respect to the retired meter issue.

34. There is no certainty as to when, or even if, legislation necessary to implement TURN's alternative securitization proposal would be undertaken and finalized.

35. There is no record as to what an appropriate level would be for a market based rate or a short-term interest rate and why it would be appropriate to use either rate in addressing the particular circumstances of the retired meter issue.

36. Greenlining's request for final oral argument is inconsistent with the requirements for presenting such argument, as detailed in the March 5, 2010 Scoping Memo. Also, the retired meter issue, the only issue not settled, was thoroughly briefed by a number of parties. A final oral argument is not necessary.

Conclusions of Law

1. The Settlement Agreement, as modified by this decision, is consistent with law, reasonable in light of the record and in the public interest.

2. The Settlement Agreement, as modified by this decision, should be adopted.

3. PG&E should be allowed to offer NTP&S that are already being offered by the other major energy utilities in a more expeditious manner than is currently available.

4. PG&E should be allowed to provide NTP&S categories already approved for other California energy utilities subject to an annual information-only report

to the Energy Division and other interested parties that describes PG&E's specific plans for expansion into these other areas.

5. In order for the Commission to better understand the ongoing effects of reprioritizations and deferrals, PG&E should provide expense and capital expenditure information for electric distribution, electric generation, and gas distribution, as detailed in the body of this decision.

6. PG&E should submit gas distribution pipeline safety reports to the Directors of the Commission's Consumer Protection and Safety Division and Energy Division, as detailed in Attachment 5 to this decision.

7. There is good reason to believe that PG&E's ratemaking proposal for retired meters was not fully understood and considered by the Commission in PG&E's two prior AMI proceedings.

8. The Commission should fully examine the retired meter issue in this proceeding and determine whether the outcome in D.09-03-026 is just or needs to be changed.

9. Since the cause of the wholesale electromechanical meter retirements was the Commission's encouragement for utilities to implement AMI and the SmartMeters that replaced them were determined to be cost-effective, it is reasonable to grant a rate of return on the unamortized net plant balance associated with those retired meters.

10. Consistent with prior Commission decisions, it is reasonable to accelerate the amortization of the net plant balance associated with electromechanical electric meters replaced by SmartMeters to six years.

11. In order to reflect reduced regulatory risk, it is reasonable to reduce the rate of return on equity to 6.55% in calculating the applicable rate of return for

the unamortized net plant balance associated with electromechanical electric meters replaced by SmartMeters.

12. With respect to the amortization of retired meters replaced by SmartMeters, PG&E should be allowed to file a compliance advice letter that sets forth the annual amortization schedule base on the reduced rate of return. This amortization schedule should then be used to determine any incremental recovery amounts related to state and federal income taxes, to the extent the information is a part of the results of operations data base for this proceeding and is consistent with the manner in which the results of operations model calculates revenue requirements.

13. In calculating the associated revenue requirements for the compliance advice letter filing, PG&E should, to the extent possible, reflect any remaining state tax depreciation and federal tax and book depreciation as deductions over the six year amortization period; to the extent applicable, reflect any increased state taxes as increased deductions for calculating federal income taxes; and reflect any other standard ratemaking adjustments that would lower the revenue requirements.

14. Greenlining's request for final oral argument in this proceeding should be denied.

O R D E R

IT IS ORDERED that:

1. The general rate case settlement, dated October 15, 2010, which resolves all but one issue in this consolidated proceeding, is adopted with modifications and clarifications. Modifications impose additional requirements for certain new non-tariffed products and services, reprioritization and cost deferrals, and gas

distribution pipeline safety reporting. With respect to clarification, Commission staff, to be designated by Commission management, shall oversee the independent audit of the booking and allocation of SmartMeter costs and benefits and the adequacy of related Pacific Gas and Electric Company guidelines. Also, to the extent that this decision adopts a different ratemaking treatment than proposed by either Pacific Gas and Electric Company or The Utility Reform Network regarding the appropriate rate of return on meter devices, the general rate case settlement is modified in that respect.

2. Pacific Gas and Electric Company is authorized to recover, through rates and through authorized ratemaking accounting mechanisms, over the remainder of 2011 the (i) revenue requirement set forth in Appendix A (Modified) of Attachment 3 to this decision, less (ii) the amount collected by Pacific Gas and Electric Company in base rates since January 1, 2011, and prior to the implementation of the revenue requirement authorized by this decision, plus (iii) interest on the difference between (i) and (ii), with said interest based on the rate for prime, 3-month commercial paper reported in Federal Reserve Statistical Release H-15.

3. Within 30 days from the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 advice letter with revised tariff sheets to implement (i) the revenue requirement authorized by this decision, and (ii) all accounting procedures, fees, and charges authorized by this decision that are not addressed in the other advice letters required by this decision. The revised tariff sheets shall (a) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (b) comply with General Order 96-B, and (c) apply to service rendered on or after their effective date.

4. Pacific Gas and Electric Company is authorized to implement the attrition revenue requirement increases for the years 2012 and 2013 as detailed in Appendix C of Attachment 1 to this decision. The attrition increases may be implemented by advice letter.

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

6. Pacific Gas and Electric Company shall allocate work credits at the same level and in the same amount as Pacific Gas and Electric Company'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.

7. Electric Research Development and Demonstration project costs shall be reasonably allocated between generation and distribution as Pacific Gas and Electric Company preliminarily outlined in Table 31-2, Exhibit PG&E-18 v3c, at 31-11 (except for energy storage, for which Pacific Gas and Electric Company has revised its forecast allocation to 50/50 generation/distribution) and, for the test year 2011 general rate case cycle, the results of Pacific Gas and Electric Company's prospective electric Electric Research Development and Demonstration 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.

8. Pacific Gas and Electric Company shall create a new major work category for its Distribution Integrity Management Program. There shall be a one-way balancing account mechanism with a cap of $60 million for Distribution Integrity Management Program costs for the term of the general rate case cycle (2011-2013). Any unspent Distribution Integrity Management Program funds at the end of this general rate case cycle shall be returned to customers in the next general rate case.

9. Pacific Gas and Electric Company's current postretirement benefits other than pensions/long term disability balancing account shall remain a one-way account. The estimate of total contributions for 2011 to the postretirement benefits other than pensions medical and life, and long term disability trusts will be $163.3 million (total company before allocation to capital and other non-general rate case Unbundled Cost Categories). This total amount shall also apply to the attrition years. In compliance with Decision (D.) 92-12-015 and D.95-12-055, Pacific Gas and Electric Company will file a consolidated true-up of the revenue requirements associated with the postretirement benefits other than pensions medical, life, and long term disability contributions at the end of the 2011 general rate case cycle.

10. Pacific Gas and Electric Company shall treat Diablo Canyon Power Plant labor costs associated with spent nuclear fuel removal, drying, loading, and encapsulation as operating expense, not capital expenditures.

11. The cost of the Diablo Canyon Steam Generator Replacement Project shall be recovered in generation rates without the need for further reasonableness review.

12. Pacific Gas and Electric Company shall transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account when the total costs of the project are known, and Pacific Gas and Electric Company shall close out the Gateway balancing account at that time.

13. With respect to the true-up of the initial cost of the Colusa Generating Station, Pacific Gas and Electric Company is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of Decision 06-11-048, when the final project costs are known.

14. With respect to the true-up of the initial cost of Humboldt Bay Generating Station, Pacific Gas and Electric Company is authorized to file an advice letter to true-up the project's initial capital cost, subject to the requirements of Decision 06-11-048, when the final project costs are known.

15. With respect to the recovery of costs in excess of the authorized initial cost of Humboldt Bay Generating Station, Pacific Gas and Electric Company 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, Pacific Gas and Electric Company shall file an application with the Commission demonstrating the reasonableness of any excess amounts.

16. Pacific Gas and Electric Company 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 Power Plant site.

17. Pacific Gas and Electric Company shall provide in its next general rate case 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 Pacific Gas and Electric Company facilities.

18. During the test year 2011 general rate case cycle, Pacific Gas and Electric Company shall record the customer retention costs incurred by its Customer Care organization below-the-line.

19. At Pacific Gas and Electric Company's expense, Commission staff shall oversee an independent audit of Pacific Gas and Electric Company's SmartMeter-related costs to determine whether costs that should have been recorded in the SmartMeter balancing accounts were instead recorded in other accounts. The cost to Pacific Gas and Electric Company of the audit shall not exceed $200,000 and shall be recoverable through the SmartMeter balancing accounts.

20. The SmartMeter Benefits Realization Mechanism adopted by the Commission in Decision (D.) 06-07-027 and D.09-03-026 shall be continued through the 2011 general rate case cycle, with adjustments as specified in the general rate case settlement, dated October 15, 2010.

21. The Commission'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.

22. Direct Access and Community Choice Aggregation fees shall be conditionally adopted as proposed. Pacific Gas and Electric Company shall file an application by January 1, 2012 to comprehensively reassess all of its Direct Access and Community Choice Aggregation service fees. Pacific Gas and Electric Company is allowed to cease recording costs and revenues to the Direct Access Discretionary Cost/Revenue Memorandum Account, pending review of the account balance in the upcoming application.

23. Pacific Gas and Electric Company's proposal to adjust reconnection fees is denied.

24. Pacific Gas and Electric Company's proposal to adjust local office hours is adopted.

25. Pacific Gas and Electric Company's Non-sufficient Funds Fee is reduced to $9 from its current level of $11.50.

26. Pacific Gas and Electric Company 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 shall be undertaken by Pacific Gas and Electric Company and shall be made available to interested parties on an annual basis.

(2) Below-the-line accounting for certain Pacific Gas and Electric Company 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 Community Choice Aggregators, 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 Pacific Gas and Electric Company Corporation employees.

27. During the term of this 2011 test year general rate case cycle, Pacific Gas and Electric Company shall not accept a permanent transfer of an employee from an affiliate (including Pacific Gas and Electric Company Corporation) unless

Pacific Gas and Electric Company 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 Pacific Gas and Electric Company, and that the compensation to be paid the employee is within market range. Prior to any such transfer, Pacific Gas and Electric Company shall memorialize its assessment of need and qualifications, including whether Pacific Gas and Electric Company interviewed other candidates to fill the position. To the extent that costs associated with such transfer of employees are sought in the next general rate case, Pacific Gas and Electric Company shall make its assessments available to interested parties in the next general rate case.

28. Concerning meals expenses, Pacific Gas and Electric Company 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 Pacific Gas and Electric Company 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.

29. Nuclear fuel and fuel oil carrying costs shall continue to be recovered through the Energy Resource Recovery Account at short-term commercial paper rates.

30. Pacific Gas and Electric Company's requests for new balancing accounts for health care costs; New Business/Work at the Request of Others/Rule 20A; renewable energy projects; uncollectibles; emergencies and catastrophic events;

and research development and demonstration expenses are denied. Pacific Gas and Electric Company shall continue with current electric and gas sales mechanism balancing accounts (Distribution Revenue Adjustment Mechanism, Utility Generation Balancing Account, Core Fixed Cost Account, and Noncore Distribution Fixed Cost Account) through 2013.

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

32. Administrative and general expenses allocated to the Unbundled Cost Categories adopted in this 2011 general rate case shall be used in determining the administrative and general expenses in related proceedings in 2011 and future years until Pacific Gas and Electric Company's next test year general rate case, if the outcome of those proceedings would otherwise require specific calculation of administrative and general expenses. Specifically, the Unbundled Cost Categories and related proceedings are: Gas Transmission (Gas Accord III and subsequent Pacific Gas and Electric Company Gas Transmission and Storage proceedings) and Nuclear Decommissioning (including SAFSTOR), the 2009 Nuclear Decommissioning Cost Triennial Proceeding and subsequent Nuclear Decommissioning Cost Triennial Proceeding filing.

33. The Memorandum of Understanding between Disability Rights Advocates and Pacific Gas and Electric Company included in Exhibit PG&E-16 as Attachment A is approved.

34. The Aglet Consumer Alliance proposal to eliminate the requirements of Decision 86-12-095 that requires Pacific Gas and Electric Company to prepare total factor productivity studies is adopted.

35. Pacific Gas and Electric Company is relieved of the requirement in Decision 04-05-055 to include information about long-term incentives, which are not funded by ratepayers, in future total compensation studies.

36. Prior to submission of a Results of Operation model in Pacific Gas and Electric Company's Notice of Intent to file its next general rate case application, the Division of Ratepayer Advocates and Pacific Gas and Electric Company shall review Pacific Gas and Electric Company's Excel-based Results of Operation model used for the 2011 general rate case, and jointly determine what changes should be made to enhance the model.

37. In future general rate cases, Pacific Gas and Electric Company shall 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.

38. Pacific Gas and Electric Company shall suspend Allowance for Funds Used During Construction accruals for the ten Transform Operations projects identified by The Utility Reform Network. Pacific Gas and Electric Company shall ensure that future requests for capital recovery of the projects do not include Allowance for Funds Used During Construction for the period starting with the dates (November 2008 for seven projects, and February 2009 for three projects) identified in The Utility Reform Network's testimony and continuing until spending on the projects resumes.

39. In its next general rate case, Pacific Gas and Electric Company shall submit testimony on the status of its workforce training programs. Pacific Gas and Electric Company 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.

40. Pacific Gas and Electric Company shall provide an annual information-only report to the Energy Division that describes, on a prospective basis, Pacific Gas and Electric Company's specific plans for expansion into any of the areas currently authorized for the other utilities. As part of the report, Pacific Gas and Electric Company shall identify 1) the underutilized or excess capacity acquired for the non-tariffed products and services; 2) the steps that will be taken by Pacific Gas and Electric Company to ensure that the project will not affect the quality or cost of the utility service; and 3) proof that the expanded non-tariffed products and services will not distort non-utility markets or be anticompetitive. The report shall be made available to the parties to this proceeding as well as the parties in Rulemaking 05-10-030. Pacific Gas and Electric Company shall not offer any such expanded service until at least 30 days after the issuance of the annual information-only report.

41. Pacific Gas and Electric Company's costs and revenues associated with the expansion of non-tariffed products and services shall be treated on a cost of service basis. Pacific Gas and Electric Company's proposals concerning the 50/50 net revenue sharing mechanism and a sharing mechanism for shareholder capital is not adopted.

42. Pacific Gas and Electric Company shall provide the following expense and capital expenditure information for electric distribution, electric generation, and gas distribution.

<u>Within 90 days of the issuance of this decision</u>:

- Pacific Gas and Electric Company's authorized budgeted amounts for 2011, as of January 31, 2011, by major work category, with an explanation of any differences with what is assumed in the Settlement Agreement for 2011.

By March 31, 2012:

- Pacific Gas and Electric Company's authorized budgeted amounts, by major work category, for 2012, as of January 31, 2012.
- The recorded amounts for 2011, by major work category, with explanations for significant deviations from Pacific Gas and Electric Company's January 31, 2011 authorized budget for 2011.

By March 31, 2013:

- Pacific Gas and Electric Company's authorized budgeted amounts, by major work category, for 2013, as of January 31, 2013.
- The recorded amounts for 2012, by major work category, with explanations for significant deviations from Pacific Gas and Electric Company's January 31, 2012 authorized budget for 2012.

This information shall be provided through compliance filings in this docket. Energy Division shall report to the Commission if it observes any spending patterns that are of concern with respect to the provision of safe and reliable service.

43. In its next general rate case, as part of its showing, Pacific Gas and Electric Company shall fully describe any reprioritizations and deferrals of costs explicitly identified in the Settlement Agreement or costs that can reasonably be imputed from the Settlement Agreement. Pacific Gas and Electric Company shall fully explain its reprioritization process, justify deferrals of specific activities and projects, and justify the implemented higher reprioritized activities and projects that were not identified in this general rate case. For activities and projects that were deferred and are now being re-requested, Pacific Gas and

Electric Company shall fully explain why they are needed now when they were able to be deferred before.

44. Pacific Gas and Electric Company shall submit gas distribution pipeline safety reports to the Directors of the Commission's Consumer Protection and Safety Division and Energy Division. The requirements of the reports are detailed in Attachment 5 to this decision. Reports shall cover activity over six month periods and continue until further notice of the Commission.

45. The undepreciated balance of electromechanical electric meters replaced by SmartMeters, amounting to $340,966,000, shall be amortized over the six-year period 2011 through 2016. The applicable rate of return on the unamortized balance shall be 6.3%. As part of Pacific Gas and Electric Company's test year 2014 general rate case, the applicable rate of return used for the retired electromechanical meters for the years 2014 through 2016 may be modified to reflect the most recent authorized returns for long-term debt, preferred stock, and a recalculated return on equity equal to the average of the most recent long-term debt rate and otherwise applicable return on equity. Whether the remaining balance should be amortized on a levelized or declining basis may also be addressed at that time.

46. With respect to the amortization of retired meters replaced by SmartMeters, Pacific Gas and Electric Company may file a Tier 2 advice letter that sets forth additional revenue requirements for this general rate case cycle on a levelized basis consistent with the discussion in this decision. In no event shall such additional revenue requirements exceed $15 million for this general rate case cycle. Such additional revenue requirements shall become effective when approved, retroactive to January 1, 2011. In the advice filing, Pacific Gas and Electric Company shall also include a schedule setting forth the actual

amortization of retired meters over this general rate case cycle, which shall be used as a basis for determining the retired metered costs in Pacific Gas and Electric Company's next general rate case covering the period 2014 to 2016.

47. The Joint Comparison Exhibit, dated July 30, 2010, is identified as Exhibit PG&E-69 and is received in evidence.

48. Energy Division workpapers, which support the Administrative Law Judge's proposed decision, are identified as Exhibit ALJ-1. Workpapers supporting the assigned Commissioner's alternate decision are identified as Exhibit ALJ-2. Workpapers supporting the assigned Commissioner's revised alternate decision are identified as Exhibit ALJ-3. Exhibits ALJ-1, ALJ-2, and ALJ-3 are received in evidence.

49. The Greenlining Institute's request for final oral argument is denied.

50. Application 09-12-020 and Investigation 10-07-027 are closed.

This order is effective today.

Dated May 5, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MARK FERRON
Commissioners

I reserve the right to file a concurrence.

/s/ TIMOTHY ALAN SIMON
Commissioner

I abstain.

/s/ MICHEL PETER FLORIO
Commissioner

I dissent.

/s/ CATHERINE J.K. SANDOVAL
Commissioner

I reserve the right to file a concurrence.

/s/ MARK FERRON
Commissioner

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.

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PACIFIC GAS AND ELECTRIC COMPANY	DIVISION OF RATEPAYER ADVOCATES
By: */s/ Jane Yura*	By: */s/ Joseph P. Como*
Name: JANE YURA	Name: JOSEPH P. COMO
Date: October 15, 2010	Date: October 15, 2010
THE UTILITY REFORM NETWORK	AGLET CONSUMER ALLIANCE
By: */s/ Robert Finkelstein*	By: */s/ James Weil*
Name: ROBERT FINKELSTEIN	Name: JAMES WEIL
Date: October 15, 2010	Date: October 15, 2010
CALIFORNIA CITY-COUNTY STREET LIGHT ASSOCIATION	CALIFORNIA FARM BUREAU FEDERATION
By: */s/ David J. Byers*	By: */s/ Ronald Liebert*
Name: DAVID J. BYERS	Name: RONALD LIEBERT
Date: October 15, 2010	Date: October 15, 2010
COALITION OF CALIFORNIA UTILITY EMPLOYEES	CONSUMER FEDERATION OF CALIFORNIA
By: */s/ Rachael E. Koss*	By: */s/ Alexis K. Wodtke*
Name: RACHAEL E. KOSS	Name: ALEXIS K. WODTKE
Date: October 15, 2010	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 Dollars)

			Joint Comparison Exhibit (PG&E-69)							
			PG&E		DRA		Settlement			
Line		2011 Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	PG&E 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

					Net Salvage Rates			Accrual Rates		
Ln	Asset Class	Note	FERC Acct.	Description	PG&E Proposed (%)	DRA Proposed (%)	Settlement (%)	PG&E Proposed (%)	DRA Proposed (%)	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

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 General						
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

					Net Salvage Rates			Accrual Rates		
Ln	Asset Class	Note	FERC Acct.	Description	PG&E Proposed (%)	DRA Proposed (%)	Settlement (%)	PG&E Proposed (%)	DRA Proposed (%)	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 $	Comparison Exhibit 8 Recorded Adjusted Lab %		Reclass EP Labor [3]	Settlement Agreement 2008 Recorded Adjusted Labor[1] $	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.

1-D1
(END OF ATTACHMENT 1)

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 (Test Year 2011, line 3, tab RO_Proposed)	3,649,588	3,303,846	(345,742)	3,267,058	36,788	8
9	Less: Total Wholesale Revenue-FERC (Line 6)	15,799	15,799	0	15,799	0	9
10	Less: Wholesale Allocation of Increase-FERC [(Line 8 - Line 7) x Line 6 / Line 7]	2,376	643	(1,734)	977	(334)	10
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)

Line No.	Description	Annual Plant in Service					Weighted Average Plant in Service					Line No.
		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)	
	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 (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 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 (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	0.002647	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 (Test Year 2011, line 3, tab RO_Proposed)	1,315,666	1,154,351	(161,315)	1,095,451	58,900	8
9	Less: Total Wholesale Revenue-FERC (Line 6)	0	0	0	0	0	9
10	Less: Wholesale Allocation of Increase-FERC [(Line 8 - Line 7) x Line 6 / Line 7]	0	0	0	0	0	10
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)

Line No.	Description	Annual Plant in Service: 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)	Weighted Average Plant in Service: 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 (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	0.003105	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 (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	0.002647	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 (Test Year 2011, line 3, tab RO_Proposed)	1,831,379	1,667,848	(163,531)	1,551,488	116,360	8
9	Less: Total Wholesale Revenue-FERC (Line 6)	27	27	0	27	0	9
10	Less: Wholesale Allocation of Increase-FERC [(Line 8 - Line 7) x Line 6 / Line 7]	12	10	(2)	6	4	10
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 (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	0.002647	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

(END OF ATTACHMENT 2)

Attachment 3

APPENDIX A (ADOPTED)

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		Adopted			
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	6,031	450	(615)	1
2	Plus Other Operating Revenue	131	151	19	151	20	149	18	(1)	2
3	Total Operating Revenue	5,713	6,797	1,083	5,914	201	6,181	467	(616)	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	3	(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	5	7	5	17
18	Subtotal Expenses:	2,440	2,872	432	2,214	(226)	2,484	44	(388)	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	4,719	328	(562)	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	16,623	1,582	(618)	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 (ADOPTED)

Summary of Increase by Electric, Gas Distribution, and Generation

PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF INCREASE OVER 2011 ESTIMATED AUTHORIZED
(Millions of Dollars)

			Joint Comparison Exhibit (PG&E-69)							
			PG&E		DRA		Adopted			
Line		2011 Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	2011 Proposed	Difference from Authorized	PG&E 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)	(115)	(19)	1	4
5	FF&U, Other Adjs, Taxes Other than Income	73	88	15	73	1	89	16	1	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	3,244	237	(290)	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	888	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)	(18)	1	25
26	FF&U, Other Adjs, Taxes Other than Income	157	188	31	154	(3)	174	17	(14)	26
27	Return, Taxes & Depreciation	3,183	3,816	634	3,613	430	3,601	418	(215)	27
28	Subtotal Retail Revenue Requirement	5,582	6,646	1,064	5,763	181	6,031	450	(615)	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.

(END OF ATTACHMENT 3)

Attachment 4

Attachment 4

Table 1-1 (Adopted)

Pacific Gas and Electric Company
2011 PG&E GRC (Adopted)

General Rate Case Revenues: Electric Distribution

Available from Present and Proposed Rates
(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED 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	3,358,335	(291,253)	3,267,058	91,278	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	923	(1,453)	977	(54)	10
	[(Line 8 - Line 7) x Line 6 / Line 7]						
11	Required Retail Revenue	3,631,413	3,341,613	(289,799)	3,250,282	91,331	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	3,243,734	(289,799)	3,150,580	93,153	13
	Increase in Proposed Revenue Over Adopted Revenue						
14	Proposed Retail Revenue Requirement (Line 13)	3,533,533	3,243,734	(289,799)	3,150,580	93,153	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	236,193	(289,799)	143,580	92,612	16

Wholesale Wheeling & Resale Revenue (line 4) and Wholesale Allocation of Increase-FERC (line 10) are attributable only to ED - Wires and Services.

Attachment 4

Table 1-2 (ADOPTED)

Pacific Gas and Electric Company

2011 PG&E GRC (Adopted)

Results of Operations at Proposed Rates
Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED v DRA (E)=(B)-(D)	Line No.
	REVENUE:						
1	Revenue Collected in Rates	3,533,533	3,243,734	(289,799)	3,150,580	93,153	1
2	Plus Other Operating Revenue	116,055	114,602	(1,453)	116,477	(1,876)	2
3	Total Operating Revenue	3,649,588	3,358,335	(291,253)	3,267,058	91,278	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	10,409	16	8,632	1,777	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	25,376	(2,208)	24,698	678	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	9,698	9,698	0	9,698	17
18	Subtotal Expenses:	1,386,282	1,194,884	(191,398)	1,073,749	121,136	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	57,664	(6,249)	63,383	(5,720)	24
25	Federal Income	272,257	269,208	(3,049)	271,107	(1,900)	25
26	Total Taxes	515,541	499,800	(15,741)	502,439	(2,639)	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	2,470,971	(280,420)	2,396,736	74,235	30
31	Net for Return	898,197	887,364	(10,833)	870,322	17,043	31
32	Rate Base	10,218,396	10,095,155	(123,241)	9,901,269	193,886	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

Attachment 4

Table 1-3 (ADOPTED)

Pacific Gas and Electric Company
2011 PG&E GRC (Adopted)

Income Taxes at Proposed Rates
Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED v DRA (E)=(B)-(D)	Line No.
1	Revenues	3,649,588	3,358,335	(291,253)	3,267,058	91,278	1
2	O&M Expenses	1,386,282	1,194,884	(191,398)	1,073,749	121,136	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	1,990,523	(93,412)	2,025,361	(34,838)	6
	DEDUCTIONS FROM TAXABLE INCOME:						
7	Interest Charges	284,071	280,645	(3,426)	275,255	5,390	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	266,037	(3,527)	261,714	4,323	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	1,296,275	(22,723)	1,266,413	29,863	21
22	Taxable Income for CCFT	764,936	694,247	(70,689)	758,948	(64,701)	22
23	CCFT	67,620	61,371	(6,249)	67,091	(5,720)	23
24	State Tax Adjustment	0	0	0	0	0	24
25	Current CCFT	67,620	61,371	(6,249)	67,091	(5,720)	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	57,664	(6,249)	63,383	(5,720)	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	1,187,253	(30,275)	1,170,624	16,630	41
42	Taxable Income for FIT	866,407	803,270	(63,137)	854,737	(51,468)	42
43	Federal Income Tax	303,242	281,144	(22,098)	299,158	(18,014)	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	269,208	(3,049)	271,107	(1,900)	50

Attachment 4

Table 1-4 (ADOPTED)

Pacific Gas and Electric Company
2011 PG&E GRC (Adopted)

Total Escalation
Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED 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	9,698	9,698	0	9,698	9
10	Total Escalated	1,327,690	1,138,484	(189,206)	1,027,656	110,828	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	9,698	9,698	(2,251)	11,949	20
21	Total Non-Escalated	1,234,182	1,057,869	(176,313)	959,328	98,541	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

Attachment 4

Table 1-5 (ADOPTED)

2011 PG&E GRC (Adopted)

2011 PG&E GRC (SETTLEMENT)

Franchise and Uncollectibles at Proposed Rates

Electric Distribution

$(000)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED v DRA (E)=(B)-(D)	Line No.
	Uncollectible Accounts						
1	Rate Case Revenues	3,649,588	3,358,335	(291,253)	3,267,058	91,278	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	3,352,290	(290,728)	3,261,177	91,113	3
4	Uncollectible Rate	0.00285	0.00311	0.00025	0.00265	0.00046	4
5	Uncollectible Accounts Expense	10,393	10,409	16	8,632	1,777	5
	Franchise Fees						
6	Rate Case Revenues from Customers	3,643,019	3,352,290	(290,728)	3,261,177	91,113	6
7	Uncollectible Accounts Expense	10,393	10,409	16	8,632	1,777	7
8	Net Rate Case Revenue from Customers	3,632,626	3,341,881	(290,744)	3,252,545	89,337	8
9	Franchise Rate	0.00759	0.00759	0.00000	0.00759	0.00000	9
10	Franchise Fees Expense	27,584	25,376	(2,208)	24,698	678	10

Attachment 4

Table 1-9 (ADOPTED)

Pacific Gas and Electric Company

2011 PG&E GRC (Adopted)

Working Cash Capital

Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED 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	48,484	(2,911)	38,521	9,964	11
12	Working Cash Capital Supplied by Investors	27,764	34,897	7,133	31,774	3,122	12

Attachment 4

Table 1-10 (ADOPTED)

Pacific Gas and Electric Company

2011 PG&E GRC (Adopted)

Ratebase

Electric Distribution

(Thousands of Dollars)

Line No.	Description	PG&E 2011 (A)	ADOPTED 2011 (B)	Difference ADOPTED v PG&E (C) = (B)-(A)	DRA 2011 (D)	Difference ADOPTED 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	34,897	7,133	31,774	3,122	8
7	Total Working Capital	102,591	109,724	7,133	95,728	13,995	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	10,095,155	(123,241)	9,901,269	193,886	22

(END OF ATTACHMENT 4)

Attachment 5

Gas Distribution Pipeline Safety Reporting

Pacific Gas and Electric Company (PG&E) shall submit semi-annual Gas Distribution Pipeline Safety Reports to the Directors of the Commission's Consumer Protection and Safety Division and Energy Division. Reports shall also be provided to the Division of Ratepayer Advocates and The Utility Reform Network (TURN), if TURN so requests. Reports shall cover activity over the first six months of the calendar year and the second six months of the calendar year and continue until further notice of the Commission. Reports shall be submitted no later than three months after the end of each six-month period.

At minimum the report shall include the following:

<u>Decision-making process</u>

1) A thorough description and explanation of the strategic planning and decision-making approach used to determine and rank which capital projects, operation and maintenance (O&M) activities, and inspections are undertaken for gas distribution pipeline safety, integrity and reliability are to be undertaken.

<u>Budgeting, spending and project reprioritization</u>

2) Amount of funds allocated in the Settlement Agreement to each Major Work Category (MWC) related to gas distribution pipeline safety, integrity and reliability for capital expenditures and for O&M expenses. To the extent they are specified in the Settlement Agreement, amounts of funds expected to be incurred for each capital project used as the basis for the settled capital expenditures. If capital projects are not specified in the Settlement Agreement, show the capital projects proposed by PG&E in its Application (A.) 09-12-020.

3) Amount budgeted for each MWC at the beginning of each calendar year.

4) Amount spent during the reporting period, year-to-date, and annual totals by MWC and for each capital project within each MWC.

5) Amount spent during the reporting period, year-to-date, and annual totals on O&M for safety, integrity and reliability.

6) Comparison of amounts spent on capital projects and O&M to Settlement Agreement allocation, showing remaining balance or amounts spent in excess of allocation.

7) Indentify and describe capital projects and O&M work that has been started and completed during reporting period including completion date and report on the status of work-in-progress.

8) Total cost of each completed capital project.

9) Reported actual costs should be directly comparable to amounts approved in the Settlement Agreement. Identify whether any reported amounts include administrative and general expenses, indirect and/or overhead costs and, if so, show these amounts.

10) Identify whether capital projects forecasted in A.09-12-020 have been started, completed, remain to be undertaken (include anticipated start and completion date) or have been reprioritized. If reprioritized, provide the reasons for the reprioritization and the justification for the new project(s). Describe the new capital project(s) including estimated start and completion date. Discuss whether funding will be requested in a future rate case application for forecasted capital projects that were reprioritized and identify these projects.

11) At the beginning of each calendar year, describe the capital projects planned to be undertaken for the year.

12) To the extent PG&E does not fully spend the amounts for capital projects or O&M related to pipeline safety, integrity management, and reliability specified in the Settlement Agreement, explain the reasons for doing so.

<u>Project descriptions and status</u>

13) Discuss status and progress of capital projects previously started and not completed. Identify and explain any discrepancies found with pipeline records. Report if no records exist.

14) Explain if a capital project is undertaken in response to a federal and/or Commission regulatory requirement or advisory and/or National Transportation Safety Board recommendation. Indentify if project was/is on Risk Management Top 100 list or was/is in a "high-consequence area."

15) Include most recent Risk Management Top 100 report if it includes gas distribution pipelines; identify changes from the prior report and explain why the changes were made.

16) Include most recent distribution pipeline inspection plan showing inspection methods to be used for specific pipeline segments and progress to plan. Note and explain any changes to the prior plan. Report on inspection results, identify and describe any discrepancies found with pipeline records. Report if no records exist.

17) Project descriptions shall include the following:

a) Project name

b) Work description: Provide details of work to be undertaken.

c) Purpose: Explain why the work is necessary.

d) Timeframe: Start to completion, including significant milestones.

e) Pipeline number

f) Mileposts

g) Geographical coordinates and location (city, place name, county)

h) Pipeline map

i) Class location

j) Identify if pipeline is in a high consequence area

k) Vintage of each pipeline segment and year installed

l) Manufacturer of the pipe

m) Whether the pipe is seamless or non-seamless

n) Maximum allowable operating pressure of the pipeline

o) Operating pressure

p) Pipeline dimensions (diameter, thickness, length) of each segment

q) Areas and communities the pipeline is providing service to

r) Explain how work on pipeline will affect service

s) Explain how work on pipeline might affect (such as operating pressure) the operation of other distribution pipelines and facilities connected to the project.

t) For exposed pipelines: Examine for external defects and report results.

u) For removed pipelines: Examine for external and internal defects and report results.

The Gas Distribution Pipeline Safety Report does not replace any existing PG&E reporting requirements, such as the Gas Pipeline Replacement Program annual reports ordered in D.86-12-095.

For capital projects proposed or forecasted in the test year 2011 general rate case (GRC), PG&E shall report on capital projects at the level set forth in the workpapers for PG&E's GRC Gas Capital testimony. For more generally referenced capital projects, PG&E shall provide information for every project with total forecasted spending in excess of $250,000 and with actual expenditures in the year of over $10,000, within each gas capital MWC. These thresholds are consistent with PG&E's annual Gas Pipeline Replacement Program reports.

Where requested information is not directly applicable to PG&E's gas distribution system, PG&E shall, when possible, provide data relevant to the area of inquiry.

Substantive changes to any of the requirements in this attachment may be implemented only after approval of the Consumer Protection and Safety Division and Energy Division.

(END OF ATTACHMENT 5)