STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

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

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Agenda ID #10175
and
Alternate Agenda ID #10176
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 09-12-020, INVESTIGATION 10-07-027

Enclosed are the proposed decision of Administrative Law Judge (ALJ) David K. Fukutome previously designated as the presiding officer in this proceeding and the alternate proposed decision of Commissioner Michael R. Peevey. The proposed decision and the alternate proposed decision will not appear on the Commission's agenda sooner than 30 days from the date they are mailed.

Pub. Util. Code § 311(e) requires that the alternate item be accompanied by a digest that clearly explains the substantive revisions to the proposed decision. The digest of the alternate proposed decision is attached.

This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM 10 days beforehand. When an RDM is held, there is a related ex parte communications prohibition period. (See Rule 8.2(c)(4).)

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

Parties to the proceeding may file comments on the proposed decision and alternate proposed decision as provided in Pub. Util. Code §§ 311(d) and 311(e) and in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 25 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ Fukutome at dkf@cpuc.ca.gov and Commissioner Peevey sponsoring the alternate, Commissioner Peevey's advisor Scott Murtishaw at sgm@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ KAREN V. CLOPTON
Karen V. Clopton, Chief
Administrative Law Judge

KVC:hkr

Attachment

Digest of Differences
Between ALJ David Fukutome's Proposed Decision
and Commissioner Michael R. Peevey's Alternate Proposed Decision

ATTACHMENT

The alternate proposed decision of Commissioner Peevey differs from ALJ Fukutome's proposed decision with respect to the authorized rate of return on the unamortized value of electromechanical meters that are replaced by SmartMeters. The alternate proposed decision sets an overall rate of return on the unamortized balance of 7.42% rather than the 5.73% stipulated in the ALJ's proposed decision. The difference in the authorized rate of return yields an annual revenue requirement that is approximately $6 million more than the revenue requirement in the ALJ's proposed decision.

(END OF ATTACHMENT)

Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER PEEVEY**
(Mailed 2/22/2011)

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 advice letter requirements for certain new non-tariffed products and services, 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 7.42% 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 $454 million, or 8.1%, over the current authorized level of $5,582 million. The authorized increase is comprised of $241 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's 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

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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.

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 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.

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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.

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 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

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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.

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 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 professionals and technical employees of PG&E. Merced ID, Modesto ID, and SSJID represent the interests of irrigation districts. WPTF represents the interests of its membership in encouraging competition in Western states electric markets. Finally, WEM represents women and men working for a rapid transition to an efficient, renewable energy system.

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 $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

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

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; 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 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,

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

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

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 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 the 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 will maintain an advice letter requirement. 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 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

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

[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.

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 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.

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[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.

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 the advice letter process, even for categories of NTP&S 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 may satisfy the requirements of NTP&S Rule VII of the Affiliate Transactions Rules, by filing a Tier 2 advice letter for approval to provide categories already approved for other California energy utilities. Such advice letters are deemed effective 30 days after filing, unless protested or the Commission staff is not satisfied and needs to suspend the advice letter for further review. The advice

letters must be served on parties to this proceeding as well as the parties in Rulemaking 05-10-030.

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.[14]

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,

[14] *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.[15]

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 . . . [16]
>
> 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.[17]

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

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

[17] 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.[18]

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 . . . [19]

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

[19] 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.[20]

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

[20] 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.[21]

By March 1, 2011:

- PG&E's authorized budgeted amounts[22] for 2011, as of December 31, 2010, by major work category (MWC), with an explanation of any differences with what is assumed in the Settlement Agreement for 2011.

By March 1, 2012:

- PG&E's authorized budgeted amounts for 2012, as of December 31, 2011, by MWC.
- The recorded amounts for 2011, by MWC, with explanations for significant deviations from PG&E's December 31, 2010 authorized budget for 2011.

By March 1, 2013:

- PG&E's authorized budgeted amounts for 2013, as of December 31, 2012, by MWC.
- The recorded amounts for 2012, by MWC, with explanations for significant deviations from PG&E's December 31, 2011 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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[21] 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.

[22] 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.[23]

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.[24] We will require PG&E to 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 should cover activity over six month periods and continue until further notice of the Commission.

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

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

[24] 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.

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 predicable 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 this issue, 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.[25]

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:[26]

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.07-012-009, and again it was unopposed. PG&E indicates the Commission approved it as follows:[27]

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.

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

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

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

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.[28] (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. 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

[28] 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.

> 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 . . . [29]

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 a lesser amount of 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.[30] That methodology was not specifically adopted in an ordering paragraph, however Conclusion of Law 50 of 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

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

[30] 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.

SmartMeter Upgrade is reasonable,[31] and PG&E's proposals with respect to retirements of plant are reflected in that model. Consequently, PG&E's meter retirement ratemaking proposal was implicitly adopted by that decision.

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) PG&E's proposal was implicitly adopted in D.09-03-026, which authorized the current 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 consider the ramifications of PG&E's proposed ratemaking in those prior proceedings.

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[31] 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.

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.[32]

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:

- 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).

[32] 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.

- 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.[33]

- 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."[34]
- 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."[35]
- 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 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

[33] 45 CPUC2d 274, 276.

[34] 64 CPUC2d 1, 62.

[35] 76 CPUC2d 627, 737.

return of 90% of the debt return is appropriate for the non-debt (i.e., equity) share of the stranded investment . . . "[36]

- 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."[37]
- 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."[38] However, the 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

[36] 64 CPUC2d 241, 272.

[37] 12 CPUC2d 150, 167.

[38] 16 CPUC2d 205, 230.

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."[39] 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."[40]

- 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."[41]
- 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

[39] 16 CPUC2d 205, 229.

[40] 16 CPUC2d 205, 228.

[41] 15 CPUC2d 123, 127.

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."[42] 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."[43]

- 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 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

[42] 20 CPUC2d 115, 143.

[43] 20 CPUC2d 115, 143.

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."[44]

- 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 . . . "[45] 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."[46]
- 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 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

[44] 18 CPUC2d 592, 599.

[45] 47 CPUC2d 143, 267.

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

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."[47]

- 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."[48]

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

[47] 57 CPUC2d 1, 54.

[48] 4 CPUC2d 725, 777.

be denied a rate of return on such assets by excluding such balances from rate base.[49] 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.[50]

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.

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

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[49] 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.

[50] 16 CPUC2d 205, 228.

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[51] 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.[52] 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 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

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

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

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:[53]

> "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,[54] 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 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.

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

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

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. 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 for rate of return)[55] 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 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.

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

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.[56]

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 6, 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:[57]

> Regulatory risk pertains to new risks that investors may face from future regulatory actions that we, and other regulatory agencies,

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

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

> 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)[58] 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 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.[59]

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[58] 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.

[59] 64 CPUC2d, 61 – 62.

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.

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, "PG&E is asking the Commission to approve a rate of return on two meters for every customer."[60] 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 for the electromechanical meters that is the average of PG&E's authorized embedded cost of long term debt and return on equity. This yields an overall after tax return of 7.42%.

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 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.

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[60] Aglet Reply Brief at 4.

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 entirely. 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.[61] In that way there would be no stranded costs as shown in the examples that were included in Appendix A to

[61] 12 CPUC2d 150, 167-168.

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.[62] 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, 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 year 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.

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

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 rates 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.[63] 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 . . . "[64] 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 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, 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:[65]

> With the burden of proof placed on the applicant in rate cases, the Commission has held that the standard of proof the applicant must

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[63] D.09-03-026 at 153.

[64] D.09-03-026 at 154.

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

> 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 provided sufficient reason for reversing the latest decision on this matter.

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 was implicitly approved by D.09-03-026. Subsequent to approval of a ratemaking calculation element, 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. Certainly, elements of the revenue requirement calculation can

be questioned in subsequent 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.

In contrast, the specific use of the current authorized rate of return that is reduced by imputing an equity cost equal to 90% of the long-term debt costs to reflect the certainty of cost recovery over an accelerated amortization period is supported by Commission precedents in similar circumstances. It is therefore preferable to the TURN and DRA alternative suggestions.

With respect to PG&E 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 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 7.42% results in a revenue requirement of approximately $91.7 million in 2011, $85.4 million in 2012, $79.0 million in 2013, $72.7 million in 2014, $66.3 million in 2015, and $60.0 million in 2013. An alternative calculation would result in 6 equal amounts of $78.2million/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 $78.2 million will be used for each of the years. 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 $59.3 million higher than TURN's recommendation of $18.9 million and $15.3 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 $469 million. This is $290 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 $128 million more in ratepayer costs when compared to TURN's 18-year amortization proposal, we have determined that, for the circumstances of this case, TURN's proposal should not be adopted.[66]

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[66] 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

Footnote continued on next page

Due to the manner in which this issue has been resolved, the authorized revenue requirement increase for test year 2011 will be $241 million (8.1%) 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 $454 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.

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.

PV cost is approximately $330 million. For PG&E's proposal, the PV cost is approximately $375 million. For TURN's proposal, the PV cost is approximately $145

Footnote continued on next page

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 _____ and reply comments were filed on _____ by _____.

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.

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million. If TURN's proposal were modified to amortize the balance over 6, rather than 18, years, the PV would be approximately $240 million.

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. There is a need for Commission review of new NTP&S to ensure compliance with Rule VII of the Affiliate Transaction Rules.

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. The 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 exceeded 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. 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.

31. 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.

32. 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.

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

34. 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.

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 file a Tier 2 advice letter for approval to provide NTP&S categories already approved for other California energy utilities.

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 the average of rate of return on long-term debt and the otherwise authorized return on equity in calculating the applicable rate of return for the unamortized net plant balance associated with electromechanical electric meters replaced by SmartMeters.

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 (PG&E) guidelines. Also, to the extent that this decision adopts a different ratemaking treatment than proposed by either PG&E 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 (PG&E) 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 PG&E 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 (PG&E) 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 PG&E'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 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.

7. Electric Research Development and Demonstration (RD&D) project costs shall be reasonably allocated between generation and distribution as Pacific Gas and Electric Company (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.

8. Pacific Gas and Electric Company shall create a new major work category 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 general rate case (GRC) cycle (2011-2013). Any unspent DIMP funds at the end of this GRC cycle shall be returned to customers in the next GRC.

9. Pacific Gas and Electric Company's (PG&E's) current postretirement benefits other than pensions/long term disability (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-general rate case (GRC) Unbundled Cost Categories). This total amount shall also apply to the attrition years. In compliance with Decision 92-12-015 and Decision 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.

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 (PG&E) 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 PG&E 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 (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, PG&E 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 (PG&E) 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 PG&E 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 (PG&E's) expense, Commission staff shall oversee an independent audit of PG&E'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 PG&E 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 (DA) and Community Choice Aggregation (CCA) fees shall be conditionally adopted as proposed. Pacific Gas and Electric Company (PG&E) shall file an application by January 1, 2012 to comprehensively reassess all of its DA and CCA service fees. PG&E is allowed to cease recording costs and revenues to the DA 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 (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 shall be undertaken by PG&E 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 (GRC) cycle, Pacific Gas and Electric Company (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.

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

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 (PG&E) requests for new balancing accounts for health care costs; New Business/Work at the Request of Others (WRO)/Rule 20A; renewable energy projects; uncollectibles; emergencies and catastrophic events; and RD&D expenses are denied. PG&E 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 (A&G) expenses allocated to the Unbundled Cost Categories (UCCs) adopted in this 2011 general rate case (GRC) shall be used in determining the A&G expenses in related proceedings in 2011 and future years until Pacific Gas and Electric Company's (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.

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 (RO) model in Pacific Gas and Electric Company's (PG&E's) Notice of Intent to file its next general rate case (GRC) application, the Division of Ratepayer Advocates 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.

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 (PG&E) shall suspend Allowance for Funds Used During Construction (AFUDC) accruals for the 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.

39. In its next general rate case, Pacific Gas and Electric Company (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.

40. Pacific Gas and Electric Company may file a Tier 2 advice letter for approval to provide non-tariffed products and services categories already approved for other California energy utilities. The advice letters shall be served on parties to this proceeding as well as the parties in Rulemaking 05-10-030.

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. PG&E'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 (PG&E) shall provide the following expense and capital expenditure information for electric distribution, electric generation, and gas distribution.

By March 1, 2011:

- PG&E's authorized budgeted amounts for 2011, as of December 31, 2010, by major work category (MWC), with an explanation of any differences with what is assumed in the Settlement Agreement for 2011.

By March 1, 2012:

- PG&E's authorized budgeted amounts for 2012, as of December 31, 2011, by MWC.
- The recorded amounts for 2011, by MWC, with explanations for significant deviations from PG&E's December 31, 2010 authorized budget for 2011.

By March 1, 2013:

- PG&E's authorized budgeted amounts for 2013, as of December 31, 2012, by MWC.
- The recorded amounts for 2012, by MWC, with explanations for significant deviations from PG&E's December 31, 2011 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 (PG&E) 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. PG&E 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 GRC. For activities and projects that were deferred and are now being re-requested, PG&E 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 7.42%. 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. Exhibit Pacific Gas and Electric Company 69 is received in evidence.

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

This order is effective today.

Dated _____, at San Francisco, California.

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated February 22, 2011, at San Francisco, California.

/s/ KE HUANG
Ke Huang

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to ensure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

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