NOTICE OF EX PARTE COMMUNICATION
OF PACIFIC GAS AND ELECTRIC COMPANY
(A.09-12-020/I.10-07-027)

ATTACHMENT A

Pacific Gas and Electric Company®

Brian K. Cherry
Vice President
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

415.973.4977
Fax: 415.973.7226

VIA EMAIL AND, TO NAMED RECIPIENTS, HAND DELIVERY
April 26, 2011

Commission President Michael Peevey
Commissioner Mark Ferron
Commissioner Mike Florio
Commissioner Catherine J. K. Sandoval
Commissioner Timothy Alan Simon
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: Application 09-12-020

Dear Commissioners:

I am writing on behalf of Pacific Gas and Electric Company (PG&E) as a follow-up to several matters relating to retired meter costs that were discussed at the All-Party Meeting in Phase 1 of PG&E's General Rate Case (GRC) held by Commissioners Sandoval and Ferron on April 20, 2011. We greatly appreciate the Commissioners' willingness to consider PG&E's concerns regarding the appropriate return to be authorized on retired assets when the Commission encourages utility assets to be replaced and finds the replacement to be cost effective.

At the meeting, PG&E representatives made reference to various materials that help to illustrate or explain PG&E's position on the proper treatment of the retired meter costs. With this letter, we are providing copies of the following materials:

1. Pacific Bell Decision, with markings (Tab A). During the meeting parties discussed the attached Pacific Bell decision (see marked portions) that addressed the problem of early retirements of equipment and stranded costs that resulted from those early retirements. The marked pages show that to the extent the early retirements were attributable to technological change, and not due to affirmative marketing practices of Pacific Bell and its affiliates (called "migration" strategies), the utility would continue to earn a full return on the stranded costs from the early retired assets. PG&E believes that concerning the current situation of utility replacements made on account of technological change, the Pacific Bell decision is the closest to being on point.

2. An early CPUC ruling and PG&E ratemaking testimony from two PG&E advanced metering proceedings, with markings (Tab B). At the meeting we also discussed an early ruling in the Commission's investigation regarding advanced metering that ordered the

utilities -- in their applications setting forth advanced metering proposals -- to identify how they planned to treat the retired meters from a ratemaking standpoint. (The applicable portion of this ruling is so marked.) In response to that request, in both PG&E's initial SmartMeter proceeding and PG&E's SmartMeter Upgrade proceeding, PG&E proposed to treat the retirements as an ordinary retirement with no reduction to net plant (i.e., rate base). The various places where the retirement of the meters was identified and discussed in PG&E's testimony are marked. PG&E's proposal engendered no controversy in either proceeding and was adopted.

3. <u>Excerpts from cross-examination by a consumer group in Southern California Edison's GRC two months before the hearings on PG&E's SmartMeter Upgrade (Tab C).</u> As discussed at the meeting, at least one consumer group has understood the utilities' proposals for some time, despite the fact that this group waited until after the investment was made to object to PG&E's proposed treatment. The attached cross-examination took place in June 2008, prior to the hearings on PG&E's SmartMeter Upgrade during which no such concerns were raised.

4. <u>Copies of PG&E's initial SmartMeter and Upgrade Decisions, marked to show the incremental cost-benefit analysis that justified replacement of the existing meters (Tab D)</u>. The purpose of this incremental cost-benefit analysis was to show that on an incremental present value revenue requirement ("PVRR") basis that the revenue requirements for the new meters (i.e., the incremental cost to customers) would be offset by incremental savings to customers that would also be reflected in rates (i.e., reduced meter reading costs and other savings). The adopted incremental PVRR cost-benefit analysis in both SmartMeter proceedings reflected a litigated outcome. In addition, the adopted incremental analysis reflected the approach that sunk costs (i.e., the cost of the existing meters) would be treated on a status quo basis (i.e., that even though the meters were being retired they would continue to be included in rate base). Had it been intended that the rate base treatment of the existing meters was to change, then that change should have appeared in the incremental cost-benefit analysis for customers.[1] For context, the incremental business analysis that was used to justify replacing the existing meters had been established earlier in the Commission directed investigation referenced in item 2 above.

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[1] In contrast, PG&E did provide that the tax benefits that were derived from early retirement (write-off) of the existing meters would be passed through to customers by a *reduction* to rate base. It would be fundamentally inconsistent to eliminate (or reduce) rate base recovery for retired meter costs while at the same time conferring on ratepayers (through a rate base *reduction*) the tax benefits derived from an immediate write-off of those same retired meter costs.

We hope these materials are helpful and should you have any questions please call.

Very truly yours,

/s/

Brian K. Cherry
VP, Regulatory Relations
Pacific Gas and Electric Company

cc : Mark S. Wetzell
Philip Weismehl
Paul Phillips
Angela Minkin
Carol Brown
All Parties on Service List A.09-12-020

TAB A

Pacific Bell Decision
D8308031
(See Marked Sections)

LEXSEE 12 CPUC 2D 150

In the Matter of the Application of THE PACIFIC TELEPHONE AND TELEGRAPH COMPANY, a Corporation, for authority to increase certain intrastate rates and Charges applicable to telephone service furnished within the State of California. In the Matter of the Application of THE PACIFIC TELEPHONE & TELEGRAPH COMPANY, a Corporation, for authorization to increase certain rates and charges applicable to telephone Service furnished within the State of California. Re Advice Letter (PT&T) No. 13640 to reprice Certain telephone terminal equipment and Besolution No. T-10292 granting approval of said Changes. In the Matter of Advice Letter filing No. 13641 of THE PACIFIC TELEPHONE AND TELEGRAPH COMPANY for authority to increase certain rates for key telephone service by $30.1 million. Investigation on the Commission's own motion into the rates; tolls, rules, charges, operations, costs, seperations, inter-company Settlements, Contracts, Service, and facilities of THE PACIFIC TELEPHONE AND TELEGRAPH COMPANY, a California Corporation; and of all the telephone corporations listed in Appendix A, attached hereto. Investigation on the Commission own motion into the rates, tolls, rules, charges, operations, Costs, Seperations, inter-Company Settlements, Contracts, Service, and facilities of THE PACIFIC TELEPHONE AND TELEGRAPH COMPANY, a California Corporation and of all the telephone corporations listed in Appendix A, attached hereto. Investigation of the Commission's Own motion into the Matter of Revision of the accounting for station Connections and related ratemaking effects and the economic Consequences of Customer-owned Premise Wiring.

Decision No. 8308031, Case No. 59849 (filed August 1, 1980; amended August 28, 1980 and October 14, 1980); 59269 (filed November 13, 1979; amended November 15, 1979); 59858 (filed August 1, 1980); 59888 (filed August 19, 1980); 63 (filed December 18, 1979); 81 (filed August 19, 1980); 84 (filed December 2, 1980)

California Public Utilities Commission

1983 Cal. PUC LEXIS 1071; 12 CPUC2d 150

08/03/83

(See Decisions 93367, 93728, and 82-08-01 for appearances.)

PANEL: **[*1]** Calvo, Victor; Grew, Priscilla C; Vial, Donald; Bagely, William T

OPINIONBY: Grimes, Leonard M

OPINION: OPINION ON ORDERING PARAGRAPHS 16.a, c, AND f OF DECISION 93367 AND REQUEST OF PACIFIC FOR ADDITIONAL DEPRECIATION ALLOWANCES

In Interim Decision (D.) 93367 dated August 4, 1981, the Commission ordered further hearings on three issues which are the subject of this decision. Those issues were set forth in Ordering Paragraphs 16.a, c, and f of D.93367 (mimeo. p.229) which ordered hearings concerning:

"a. An appropriate method for allocating to the proper user any net stranded investment as a result of Pacific's migration strategy and the establishment of nonregulated operations on March 1, 1982, as required by the FCC Computer Inquiry II decision."

* * *

"c. Studies by Pacific and the staff to determine the kinds of equipment which may have been retired prior to being fully depreciated, the associated amount of undepreciated or stranded investment, and a method for recovering fairly any stranded investment."

* * *

"f. Depreciation rates used for ratemaking."

In that same decision the Commission commented at mimeo. p. 42 on the **[*2]** overall percent condition of The Pacific Telephone and Telegraph Company's (Pacific) reserve account which the Commission considered to be too high.

In November 1981 Pacific filed new remaining life rates with this Commission for all of its depreciable plant. This filing was part of an annual eview of depreciation rates for Pacific under the Commission's determination of straight line remaining life depreciation for ratesetting purposes.

On January 28, 1982 the Federal Communications Commission (FCC), as a result of an earlier request by the affiliated Bell System companies including Pacific, approved represcribed customer premises equipment (CPE) depreciation rates. On February 4, 1982 this Commission adopted Resolution RRD-10 approving new 1981 remaining life rates for Pacific. This approval included new rates for CPE consistent with the CPE rates approved by the FCC in its January 28, 1982 order. In granting this approval the Commission noted that revenues to offset the increased depreciation expense were under consideration in the continued hearings in Application (A.) 59849, this proceeding.

As ordered by D.93367 further hearings were held during 1981 and 1982 on the three **[*3]** matters covered by Paragraph 16.a, c, and f, including a public hearing on July 12, 1982 in San Francisco. In response to Paragraph 16.f Pacific filed exhibits and gave testimony at the further hearings which adjusted upward the depreciation rates found reasonable for test year 1981 in D.93367. That upward adjustment of depreciation translated to a request by Pacific for an increase in revenue requirement for the test year 1981. The Commission staff (staff) and other parties maintained that Pacific had not satisfied the notice requirements applicable to rate increases and, therefore, its request for increased rates due to additional depreciation should be denied. A formal objection was made through a written motion filed by certain intervenors on February 3, 1982, joined in by a written response of the staff on February 26, 1982, and orally by the City and County of San Francisco at the March 18, 1982 hearing. Pacific opposed the motion primarily because the additional revenue requested was within the total amount requested in A.59849 less the amount granted by D.93367 and because D.93367 was an interim decision which ordered further hearings on the level of depreciation. The **[*4]** motion was denied by the presiding administrative law judge (ALJ). We affirm the ALJ's ruling.

Pacific later made a motion to the ALJ for leave to file a written amendment, its third, to A.59849; it included in that motion a request that the Commission or the ALJ approve its request as being consistent with the Commission's Regulatory Lag Plan under which A.59849 had been filed originally. By written ruling filed June 4, 1982 the ALJ granted Pacific's motion noting that its request met all applicable Commission rules and resolutions. We affirm the ALJ's ruling.

Thereafter, on June 7, 1982, Pacific filed its third amendment to A.59849 which requests the Commission to authorize additional revenues for Pacific of $69.9 million per year to cover these items: the increase in 1981 depreciation expense approved by the Commission on February 4, 1982, a change in how depreciation reserve balances are calculated for ratemaking purposes, and an increase to reflect adoption of a modified straight line depreciation method. Specifically, Pacific requests the following increases for test year 1981:

1. An increase of $46.5 million due to the represcription of terminal equipment and digital **[*5]** data system equipment depreciation to reflect shorter service lives and revised salvage factors as approved by the Commission on February 4, 1982.

2. An increase of $9.1 million to reflect the approval by this Commission on February 4, 1982 of 1981 straight line remaining life depreciation rates for all plant accounts other than terminal equipment and digital data system equipment.

3. An increase of $9.2 million to reflect the use of account average remaining lives in plant and depreciation reserve balances as of the beginning of the test year in which the rates are applicable (effective for year 1981 and thereafter) to replace the present method of calculating depreciation rates using account average remaining lives in plant and depreciation reserve balances as of the beginning of the year previous to the test year.

4. An increase of $5.1 million to reflect the proposed adoption of the straight line equal life group (SLELG or ELG) depreciation method for outside plant accounts beginning with 1981.

The Issues

In D.93367 we discussed extensively the matter of Pacific and the Bell System installed base migration strategy. In addition to what we view as a very high percent **[*6]** condition or net plant factor (NPF) n1 for Pacific's reserve account we found that as a result of Pacific's embracing the Bell System migration strategy there might be stranded investment n2 in Pacific's accounts for which there would be no reasonable recovery other than an increase in depreciation rates or some sort of write-off. The migration strategy involved coaxing Bell System equipment customers to replace installed equipment with newer, more modern, Bell System equipment. This was done through special marketing strategies and pricing structures. The displaced older equipment was not always fully depreciated or reusable at other locations. Under the group depreciation accounting method used by Pacific the undepreciated investment is left on the books as rate base even though the asset is retired. This comes about because under group depreciation retired equipment is considered fully depreciated regardless of its age at retirement. For example, if we have an investment account totalling $1,000 with a depreciation reserve of $200, the undepreciated investment is $800 and the percent condition of the account or NPF is 80%, $800/$1,000. Now assume that part of the $1,000 **[*7]** is a single unit which has an investment of $100 and a life of five years which is equal to the average of the entire group. under group depreciation, a percentage of the $1,000 is booked each year in the depreciation reserve, that percentage being determined by the average life of all units making up the $1,000, including our $100 unit with its life of five years. Further, assume the $100 unit is retired early, say after three years of service instead of five. Under unit depreciation it would have accumulated a reserve of $60, three years times $20 per year.

n1 Percent condition or NPF is the ratio of undepreciated investment to total investment.

n2 Pacific chooses to call it a reserve deficiency.

However, under group accounting when the item is retired, $100 is retired from the investment account and $100 from the depreciation reserve. So after its retirement, the investment account equals $900 and the reserve account $100 for an NPF of 89%, $800/$900. Note that the undepreciated investment (rate base) has not changed, remaining at $800, the NPF has increased, and the investment against which the depreciation percentage is applied has been reduced. We have disregarded **[*8]** salvage value and cost of removal in this example, neither of which would change the principles illustrated. Simplistically, one can say there is $40 of stranded investment in the account or, when the asset was retired, there was a reserve deficiency of $40. What happens now? Under our remaining life theory of depreciation for ratemaking purposes, we would reevaluate the depreciation percentage we have been applying based on the estimated overall remaining life for the account, a process called "represcription." Under our example, the percentage we have been applying would be raised, that is, the remaining life of the group as a whole would be reduced, which also is what has been happening in actual practice with Pacific. Suppose we had been applying a depreciation rate of 20% to the account. The depreciation would be $200 per year, 20% of $1,000. With no additions or retirements to the account, the undepreciated investment would have been written off in four years, $800/$200. After the retirement of our unit, there is only $900 to apply the 20% rate to, resulting in $180 per year of depreciation. Now it will take 4.4 years to write off the remaining investment, $800/$180. **[*9]** If we still want to write it off in four years, the depreciation rate must be represcribed to 22.2%, $200/$900. Where we formerly had an indicated average life of five years for the total account, 100%/20%, the indicated average life is now 4.5 years, 100%/22.2%.

Pacific's witnesses, in particular Roger H. Bohl, an assistant vice president for Pacific, readily acknowledge there is a reserve deficiency. That deficiency is explained as an underaccrual of depreciation in past years resulting in a lower than adequate depreciation reserve. No matter what one calls it, the record is clear that Pacific's reserves are too low because the NPF is too high. That could result from several things. First, inaccurate estimates of the average service life and net salvage value of equipment. Second, premature retirement of equipment because of improvements in the state of the art. Third, for the terminal equipment, premature retirements resulting from the migration strategy, i.e. raising prices on older equipment in hopes users would buy new equipment, thereby causing the older equipment to have an earlier than normal retirement, and, fourth, the increasing growth rate.

Other issues have **[*10]** come up during these proceedings because of the FCC Computer Inquiry II (CI-II) decision requiring the establishment of fully separated subsidiaries to handle the sale and furnishing of equipment formerly provided by the operating companies such as Pacific n3 and the modified final judgment (MFJ) in the antitrust case now before Federal Judge Harold H. Greene. Some of the issues resulting from those actions we are addressing outside these proceedings, for example, our filings in the MFJ matter with Judge Greene.

n3 By FCC order this was done effective January 1, 1983.

Our concern with the above issues prompted our ordering the further hearings to cover the matters noted by Ordering Paragraphs 16.a, c, and f of D.93367. The main issue in this phase may well be whether the parties, in particular Pacific and the staff, have answered all of the questions we posed by way of those paragraphs.

Pacific's Showing

William M. Turk, a division staff manager, testified for Pacific concerning differences in depreciation methods and the depreciation changes which would be made if the Commission were to grant Pacific's request. Turk also detailed the calculations underlying the revenue **[*11]** requirement increase of $69.9 million. He testified that depreciation is a process to account for capital consumption with the two principal objectives of assuring that capital invested in depreciable plant is fully recovered over the plant's useful life and is allocated as accurately as possible to the accounting periods in which the capital is consumed.

Pacific presently employs the straight line vintage group (VG) whole life method of depreciation for its books of account kept in accordance with FCC rules; for intrastate ratemaking purposes in California the straight line vintage group remaining life (VGRL) method is required by this Commission. Turk testified that neither VG nor VGRL achieve the two objectives of depreciation accounting he identified because they do not correctly attribute depreciation to the time periods in which plant is consumed and in the case of VG full recovery of the original cost of assets is not assured.

Turk testified that Pacific's book depreciation reserve declined from 24% of depreciable plant in 1950 to 22% in 1970. Since 1970 the depreciation reserve percent has declined at an even faster rate; by the end of 1980 the reserve was only 19% of **[*12]** depreciable plant investment. n4 Turk testified that, on the other hand, depreciation reserve for Standard and Poor's 400 industrials is approximately 38%.

n4 The comparable NPF would be: 1950 - 76%; 1970 - 78%; 1980 - 81%.

Turk stated that competition and accelerating technology are shortening the service lives of Pacific's plant. He expects those underlying forces to continue and become even more pronounced, further accelerating the reduction in service lives. He believes a more timely response to those forces is needed to improve the capital recovery process and recommends review of capital asset life characteristics on a yearly basis rather than every three years.

Turk stated that the FCC has recently approved the SLELG depreciation method for plant additions. He claims this method, which Pacific is asking the Commission to accept for ratemaking purposes, will assure that depreciation accruals will more accurately match the consumption of capital over time; he claims that, in the long run, the revenue requirement is less.

The following will serve as an example of how the three methods discussed differ. n5 Assume four groups of equipment are put into service January **[*13]** 1 of any year; estimated lives for the four groups and investment are as follows:

	Life	Investment
Group 1	1 Yr.	$100
Group 2	2 Yrs.	100
Group 3	3 Yrs.	100
Group 4	4 Yrs.	100
Total		$400

n5 Appendix A contains a more detailed illustration of the differences and is taken from Turk's Exhibit 415.

Straight Line Vintage Group Whole Life (SLVGWL)

Average Service Life = 1+2+3+4 / 4 = 2.5 Yrs.

Depreciation Rate = 100% / 2.5 = 40%

Year	Investment	Book Depreciation at 40%
1	$400	$160
2	300	120
3	200	80
4	100	40
Total		$400

Straight Line Vintage Group Remaining Life (SLVGRL)

Year	Investment	Depreciation Reserve a	Depreciated Investment	Average Remaining Life b	Book Depreciation
	(1)	(2)	(3)=(1)-(2)	(4)	(5)=(3)/(4)
1	$400	$0	$400	2.5	$160
2	300	60	240	2.0	120
3	200	80	120	1.5	80
4	100	60	40	1.0	40
		Total			$400

a End-of-year reserve less retirements

Yr. 2 = 0 + 160 - 100 = 60.

Yr. 3 = 60 + 120 - 100 = 80, etc.

b Yr. 1 = 1+2+3+4 / 4 = 2.5, Yr. 2 = 1+2+3 / 3 = 2.0, etc.

Straight Line Equal Life Group (SLELG)
Straightline Depreciation By Equal Life Group

Year	Group 1	Group 2	Group 3	Group 4	Total All Groups
1	$100	$50	$33	$25	$208
2		50	33	25	108
3			34	25	59
4				25	25
	Total				$400

[*14]

Comparison of Straight Line Book
Depreciation By Method

Year	Vintage Group Whole Life	Vintage Group Remaining Life	Equal Life Group
1	$160	$160	$208
2	120	120	108
3	80	80	59
4	40	40	25
Totals	$400	$400	$400

It will be noted that VGWL and VGRL are identical in the above example. In actual practice, VGWL will not recover full investment if the average service lives are reduced from those estimated when the assets were put into service. Appendix A of this order illustrates this point.

Turk claims the SLELG method is superior to SLVG primarily because it more accurately matches capital recovery with capital consumption. He believes capital recovery by the SLVG method is too low in the early years of assets and too high in the later years. This is because SLVG reflects the average life of all groups in a vintage. In contrast, the subgrouping of a vintage into equal life groups makes it possible to attribute the capital consumption for each equal life group on a straight line basis over the life of each group. Thus, the capital cost of each equal life group is booked over the same time period the group actually **[*15]** provides service. This also results in timing the amount of capital recovery more closely to match the timing and amount of capital consumption over the life of the entire vintage and there is no lag in capital recovery as occurs with SLVG depreciation.

Turk commented on a possible recordkeeping problem in the actual calculation and implementation of SLELG. He claims that modern data processing methods give Pacific the ability to implement SLELG depreciation at very little cost in relation to the benefits of SLELG.

Turk pointed out that for intrastate ratemaking purposes Pacific will continue to use the SLVG remaining life method for plant put in service prior to Commission approval of SLELG. Pacific plans a phase-in approach similar to that approved by the FCC. Pacific would apply SLELG for outside plant additions in 1981, central office equipment in 1982, and all other applicable accounts in 1983.

In summarizing his recommendations Turk stated there are five depreciation accrual increases which come about as a result of his recommendations:

1. Replacement of 1980 remaining life depreciation rates with 1981 rates. The 1980 rates were used in A.59849 results of operations **[*16]** for the 1981 test year.

2. Elimination of the lag in reserve, remaining life estimates, and plant balances used in computation of current year remaining life rates.

3. Implementation of a reserve allocation filed by Pacific with the FCC.

4. Represcription of CPE lives.

5. Implementation of the SLELG method.

Bohl summarized the filings of Pacific in this phase of the proceedings and, most importantly, offered rebuttal testimony on the contentions of Users Group and California Interconnect Association (Interconnect Association) concerning stranded investment. Bohl's rebuttal testimony will be discussed after a summary of the staff and intervenor's testimony.

Staff's Showing

Kevin P. Coughlan, senior utilities engineer in the Commission's Revenue Requirements Division, testified for the staff. He stated that if there were no legal obstacles to the recovery of revenues associated with the changes in depreciation expense requested by Pacific, he would have no objection to the changes except for the change to equal life group depreciation accounting. Coughlan is not opposed to equal life group depreciation if it is applied to single units of plant but is opposed to its **[*17]** application to groups of plant. He stated that depreciation is not simply a process of feeding retirement data into a computer and generating mortality curves upon which equal life group depreciation can be determined. He prefers to continue the use of straight line remaining life depreciation which, in his opinion, more correctly matches the life characteristics and depreciation for Pacific's plant.

Coughlan claims that Pacific's witness Turk compared only total dollars of revenue requirement in attempting to show that the revenue requirement under equal life group depreciation would be less than under straight line vintage group depreciation. Coughlan points out that Turk did not take into account the time value of money. He discounted the revenue requirement flow of Turk's exhibit at 12.91% interest, the rate of return granted Pacific in D.93367, and thereby showed that when present worth of future payments required from customers under the two depreciation methods is considered, VG is less costly in the long run for Pacific's customers than the ELG method. Coughlan claims generalizations regarding depreciation practices for a single unit are not always appropriate for groups **[*18]** of property. A single unit may be considered to have a finite life but groups of plant undergoing continuous replacement may be considered to have an indefinite life.

Coughlan believes Turk's comparison of the depreciation reserve of Pacific with Standard and Poor's 400 industrials has no relevance to the proceeding. He cites as one of the reasons for Pacific's depreciation reserve decline from 24% in 1950 to 19% in 1980, Pacific's large annual construction program. He pointed out that Pacific's construction budget had increased at an annual rate of approximately 10%, 1946 through 1975. However, since 1976 the budget has increased at an annual rate of approximately 16%. He claims that new plant added at an increasing rate tends to drive the relative depreciation reserve lower. He pointed out that Pacific's depreciable plant has increased from $8.2 billion in 1976 to $14.9 billion in 1982, not including station connections, a compound growth of about 10.5% per year. He further stated the Commission has recently approved higher depreciation rates for Pacific raising its composite depreciation rate from 4.3% in 1976 to 5.6% in 1981 excluding station connections. He also stated **[*19]** that (1) depreciation reserve as a percent of investment will tend to stabilize at a certain level even under growth, (2) the higher the growth rate the higher the NPF, and (3) the NPF will vary with the type of life curve used. He offered a National Association of Regulatory Utility Commissioner's committee on depreciation paper published in 1960 which shows such a phenomenon. See Chart I for an example. This lends some support to the contention by intervenors that the increase in NPF is due to factors other than growth, factors such as earlier than anticipated retirements. However, it appears possible that the NPF will increase to some extent if the growth rate increases.

CHART 1

DEPRECIATION RESERVE BASED ON GROUP PLAN, STRAIGHT LINE METHOD

Clase of Plant with Following Characteristics:

1. Consisting of numerous similar units undergoing continual replacements at rates of growth specified below
2. Life characteristics defined by No. 1 life table and average service life of 10 years

Users Group Showing

Dr. Lee L. Selwyn of Economics and Technology, Inc. testified for Users Group. Selwyn believes Pacific has attempted to sidestep the stranded investment **[*20]** issue in this proceeding by asserting it does not exist, a position taken at the same time Pacific was asking the Commission to approve increased depreciation allowances of almost $70 million and negotiating with the FCC and the staff for even higher rates. Selwyn asserts the requirement for higher depreciation is a direct and inescapable consequence of the Bell System's migration strategy.

In our recent decision on costing procedures for telephone companies, D.83-04-012, we included Selwyn's discussion and example of how stranded investment occurs. Selwyn had two customers, A and B, coming on line at Pacific at the same time, each taking a $10,000 piece of equipment. Using straight line depreciation and a five-year life, the equipment would be depreciated at $4,000 per year. By the end of the third year, $12,000 of the original investment of $20,000 would have been depreciated and the net undepreciated investment would be $8,000. Selwyn assumed customer A discontinued service and his equipment was retired at the end of three years because it was no longer used or useful in Pacific's business. As noted in a similar example earlier in this decision, under group accounting procedures, **[*21]** the investment for A's piece of equipment, $10,000, is retired from the capital and reserve for depreciation accounts leaving $10,000 capitalized with a reserve against it of $2,000. The customer that remained with Pacific, B, would now be faced with an NPF in the account of 80%, $8,000 of undepreciated investment out of a total of $10,000. The $8,000 would have to be recovered from B over the two years remaining life of his equipment; that would amount to $4,000 per year, double the previous depreciation accrual. If B continues to pay the $2,000 per year because of no change in rates, then some other ratepayers must pick up the difference in order for Pacific to recover its authorized revenue requirement. If B is charged for the stranded investment, he will have paid $14,000 in depreciation for a $10,000 piece of equipment and A would have paid the other $6,000 of the $20,000 total. Selwyn claims the stranded investment in this example was caused by A's departure from Pacific, for whatever reason, and that departure leaves stranded investment to be recovered through rates charged by Pacific. Selwyn maintains that if customer A's decision to discontinue service were influenced **[*22]** by an affirmative effort by Pacific to migrate A to another Pacific service, then the cost causer is really Pacific and not its customers. Under the revenue requirement approach to ratemaking, coupled with Pacific's ability to seek higher depreciation charges, Pacific would not be held responsible for any of the costs of the premature retirement of A's equipment even if that retirement were a result of the migration strategy. Thus Pacific escapes responsibility for any negative aspects of its marketing practices. Selwyn believes the stranded investment problem occurs whenever equipment is retired prior to being fully depreciated. He claims that Pacific's solution for the treatment of stranded investment, that is, represcription of equipment lives through the remaining life theory of depreciation accounting, assigns no responsibility to early-departing customers or Pacific for the premature retirements.

Selwyn's example, of course, has the infirmities inherent in an isolated situation. But even though the size of Pacific's customer base is several hundred thousand and, in some cases, several million, the example serves to illustrate the problem. Under the group depreciation **[*23]** methods used by Pacific, Selwyn concedes that some units of equipment will be retired prior to the average service life for a given group and others will serve beyond that point. If, however, some event occurs which effectively shortens the life expectancy after the depreciation rate has been set, a disproportionately high number of units could be retired ahead of their expected service life and, unless the depreciation rate is represcribed, the total investment will not be recovered. In any case, earlier than normal retirements will produce stranded investment which has to be recovered somehow.

Selwyn was the only witness in this phase of these proceedings to make an attempt at quantifying stranded investment. He introduced two estimates, each arrived at by different methods, and each covering different periods. The broadest estimate was made from Pacific's witness Turk's Exhibit 417. Here Selwyn estimated the stranded investment might be as high as $95.7 million on January 1, 1981 for the account 234-Other, which is the bulk of the investment for large PBX installations excluding the newer electronic equipment; it is, therefore, a more "seasoned" account. Selwyn used Turk's **[*24]** estimate of a theoretical depreciation reserve for the account of $169.6 million and compared that to actual book reserve of $73.9 million to obtain the $95.7 million. Selwyn made a more limited estimate for the total 234 account by estimating what 1980 and 1981 retirements would have been based on a 1970-79 retirement trend and then comparing that to actual 1980-81 retirements; by this method, Selwyn concluded that about $19 million of the total 234 account retirements could be directly attributed to Pacific's marketing programs.

Selwyn opposes Pacific's proposal for ELG depreciation. His opposition centers mainly on the effects ELG depreciation would have on customers when used in concert with the revised equipment costing procedures proposed by Pacific, procedures which have, in the main, been rejected by the Commission in D.83-04-012. Selwyn disputes Pacific's claims that under ELG costs to customers can be reduced because even though depreciation charges in the early years will be increased, in the long run depreciation and rate base will be reduced requiring less revenue to support return on investment. According to Selwyn the customers will never really be afforded the **[*25]** opportunity to benefit from the lower levels of depreciation and rate base because Pacific will always operate under conditions of growth and inflation. He believes the present so overshadows the future that the theoretical benefits will not be felt to any meaningful extent in future periods.

Selwyn testified that aside from his specific opposition to ELG, Pacific, in general, should not be granted any increases in depreciation allowances at this time. He believes the recovery of increased depreciation sought by Pacific is a direct consequence of Pacific's marketing programs; approval of increased depreciation, which could lead to increased monthly rates for Pacific's terminal equipment prior to the resolution of the migration issue, will only result in a further stimulation of premature discontinuances of services creating additional stranded investment and upward pressure on Pacific's revenue requirement. Also, Selwyn cited the impending changes in Pacific's investment, reserve, and depreciation expense in relation to its revenue requirement resulting from FCC decisions and the antitrust settlement as a further reason to make no changes in Pacific's depreciation allowances at **[*26]** this time.

Selwyn further testified that Pacific's equipment retirement practices were not in the best interests of ratepayers. He believes the Commission should require Pacific to dispose of equipment at the best possible salvage price rather than junk most of it as is now being done. As discussed above, when equipment is retired from service, any unrecovered book value remains in the rate base. Also, any salvage value received is deducted from rate base and any cost of removal is added to the rate base by Pacific's accounting procedures. Therefore, claims Selwyn, Pacific has an incentive to accept minimal salvage values coupled with high costs of removal when retiring equipment. Until Pacific adopts the practice of disposing of used equipment at the highest possible price based on arm's length transactions in the public marketplace, Selwyn urges the Commission to reject any increases in revenue requirement based on increases in depreciation levels. Selwyn recommends the Commission require Pacific to retain at stockholder's expense, an independent appraiser to value Pacific's used equipment at fair market prices; if Pacific persists in its policy of selling such equipment **[*27]** only for scrap value, then the difference between the scrap value and the appraised fair market value should be considered a below-the-line expense and charged to Pacific's stockholders.

Interconnect Association's Showing

John W. Wilson, president of J.W. Wilson & Associates, Inc., testified for Interconnect Association. Wilson testified that one problem with Pacific's proposal is that in the 234 account (large PBX) remaining lives would be represcribed for each depreciation reserve subgroup based on Pacific's marketing objectives. He believes this would increase the premature obsolescence problems associated with Pacific's customer premises equipment migration strategy and contribute significantly to the cost burdens of Pacific's local exchange monopoly ratepayers. He reasons that represcription of service lives to carry out marketing objectives would result in higher depreciation rates for older equipment and make it even more likely that customers would migrate to the Bell System's newer and more modern equipment. This would enlarge the stranded investment problem leaving monopoly ratepayers to pick up the associated costs because of the pending divestiture in 1984 under **[*28]** present agreements. Wilson concludes that Pacific's current pricing strategy would assist the Bell System's objective of obtaining a competitive terminal equipment sales advantage at the expense of local exchange monopoly ratepayers.

Wilson stated that Pacific and other operating telephone companies in the Bell System have, in the past, determined plant depreciation lives based on studies designed to reflect the engineering properties of equipment. Now Pacific is proposing to shift from engineering service life estimates to a depreciation approach that reflects marketing circumstances and considerations. He stated that according to the Bell System its new product life cycle forecasts are based on:

1. The changing needs of customers.
2. The introduction of planned replacement products.
3. Bell System's marketing plans for pricing and promotion of current products.
4. Both current and anticipated future technology.
5. Competitiveness in the products market segment.
6. Strategic long-term company objectives.
7. Potential for customer ownership.

Wilson believes that to accurately assess the impact of the proposed depreciation revisions it is essential to evaluate them **[*29]** in connection with the Bell System's marketing strategies. He claims the new market forecast approach to determining equipment remaining lives gives the Bell System almost total discretion over the determination of depreciation expenses charged to competitive and monopoly ratepayers. He believes the specific depreciation proposals advanced by the Bell System serve to favorably position the Bell System in potentially competitive business terminal equipment markets at the expense of monopoly utility ratepayers. With the aid of the proposed new depreciation rates, the Bell System would be able to achieve its market goals and effectively subsidize the changeover of terminal equipment by leaving behind the burden of undepreciated retired plant in the monopoly utility service rate base. He claims that represcriptions resulting in shorter service lives on older equipment will lead to grossly higher tariffs on that equipment making the migration strategy a self-fulfilling prophesy. He claims that shortening service lives indicates that an error in judgment was made in the past and, in an unregulated market, the burden of past mistakes should be borne by shareholders. However, in a monopoly **[*30]** situation it can be shifted to the ratepayers unless regulators such as this Commission recognize what is happening and make appropriate allowances. One way to do this, claims Wilson, is to take the unrecovered capital costs associated with premature retirement of equipment resulting from the migration strategy and directly allocate those costs to the services which replaced the prematurely retired equipment. He concedes that there are, of course, circumstances where early retirements of rate base properly ascribed to the franchised monopoly should be borne by the ratepayers using the franchise service because overall there would be a benefit to the ratepayers; but he believes charging the monopoly ratepayers for mistakes made by management or extraordinary write-offs resulting from marketing practices is totally improper and unfair to general ratepayers and the Bell System's competitors. He stated that no competitor of the Bell System would be able to enjoy the unfair advantage of spreading the costs of early retirement to some other product line.

Wilson recommended that the Commission order Pacific to file a report of the equipment retirements that have resulted from its dimension **[*31]** PBX and horizon installations. A detailed report of this type would allow the Commission to assess the costs of early equipment retirement resulting from Dimension and Horizon service installations thereby preventing the spreading of such retirement costs to general telephone ratepayers as he believes is now being done. Alternatively he believes that shareholders, not monopoly ratepayers, should bear the cost of premature customer premises equipment retirements especially since such premature retirements are being used to position the Bell System in competitive markets. He believes that if the Commission were to adopt this policy it would only be prescribing a course that would automatically take place if the Bell System were already deregulated and all of its markets were competitive. Under competitive conditions shareholders would bear the risks of obsolescence and would have to pay for the cost of the Bell System's competitive repositioning.

Rebuttal Showings and Discussion

Bohl summarized the filings of Pacific in this phase of the proceedings and also offered rebuttal testimony concerning the contentions of Users Group on stranded investment. The primary purpose **[*32]** of Bohl's rebuttal testimony was to refute certain contentions made in the presentations of Selwyn and Wilson appearing for Users Group and Interconnect Association. Essentially Bohl does not quarrel with the fact there is a reserve deficiency or stranded investment on Pacific's books. However, Bohl claims there is no stranded investment as a result of the alleged migration strategy. Bohl offered a long series of tables containing calculations to prove that Selwyn's estimates of stranded investment were erroneous and that the method used by Selwyn would indicate stranded investment even where lives of equipment did not deviate from the original forecast made when first setting depreciation lives for a group of equipment.

Bohl disputed the charge that depreciation deficiencies, and hence anticipated increases in depreciation allowances, are a direct consequence of Pacific's marketing programs and practices, that is, the embedded base migration strategy. Bohl claims the decline in lives is a result of competition brought about by technological advances coupled with changes in regulatory policies; he offered an exhibit which showed a steadily increasing pattern of retirements expressed **[*33]** as a percent of gross investment beginning long before any alleged migration strategy is claimed to have existed. Bohl's presentation can be summed up as a statement by Pacific that it has not engaged in any migration strategy, that any reserve deficiency or stranded investment on the books is a result of forces and factors existing for many years, forces which existed long before any migration strategy is alleged to have guided Pacific's terminal equiment marketing activities.

Bohl testified that the depreciation rates for which Pacific is seeking rate relief reflect increased depreciation expenses resulting from a longstanding pattern of shortening lives. He believes the evidence cited by witnesses Selwyn and Wilson to support their contention that Pacific has somehow created the problem does not withstand careful analysis. He believes Selwyn's testimony regarding the computation of stranded investment is not logical and does not support Selwyn's contentions. On the contrary, Bohl believes careful consideration of the totality of the evidence points very clearly to the conclusion that a changing marketplace and its effect on product lives bears the primary responsibility for **[*34]** the low level of the depreciation reserve for terminal equipment. Bohl believes that ELG depreciation has elements that, if adopted, will serve to reduce the extent to which the Commission will have to contend with the inordinately low depreciation reserve levels in the future.

In Exhibit 507, Bohl's rejoinder testimony on stranded investment, he states that the prescribed remaining lives for account 234 property (large PBX), have decreased from over ten years in 1973 to 4.5 years in 1981. Two-thirds of this decrease occurred prior to the date cited as the initiation of the migration strategy, which Selwyn claims to have been about April 30, 1980. It appears we can conclude that in the eight-year period from 1973 to 1981 two-thirds of the decrease in lives for account 234 occurred in a 6 1/2-year period and one-third in a 1 1/2-year period. This would support Selwyn's testimony.

Bohl disputes Selwyn's computation of his $19 million stranded investment estimate which Selwyn calculated by using the deviation from the straight trend line over the period 1979 through 1981 that occurred for the actual retirements made during that period. He computed these at 1.5% points in 1980 **[*35]** and 3.3% points in 1981. Bohl contends that this is not a valid approach because it fails to consider the numerous factors that could cause an increase in the rate of retirements. Bohl claims the increase in retirements is attributable to the growth of competition in the marketplace and proceeded to make some computations based on stations in service for large customer premise systems in Pacific's territory over the period 1974 through 1981. Bohl claims that it was an incursion of Pacific's competitors that caused the premature retirements, not Pacific's marketing practices.

Bohl calculated that the replacements of station lines that Pacific lost equate to about 4.8% points of the additional retirements over the two years used by Selwyn in his analysis; he claimed that this amount essentially matches the deviation from Selwyn's trend line for the years in question. He concludes that almost all of the additional retirements computed by Selwyn are attributable solely to market share losses by Pacific rather than to Pacific's marketing strategy. Bohl also testified that an analysis of engineering records of PBXs removed from 1981 to August 1982, shows that for both 1981 and 1982, **[*36]** 38% of the Pacific PBX systems removed were replaced by PBXs of Pacific's competitors.

Bohl goes on to state that technological change has contributed to the ability of Pacific's competitors to increase their rate of success in replacing Pacific's PBXs. He claims reductions in cost and increases in capability from advancing technology enable Pacific's competitors to meet the telecommunications needs of customers now served by Pacific.

In summary, Bohl said that comparisons drawn by Selwyn provide no support for Selwyn's conclusion that a migration strategy caused Pacific's account 234 to have a high NPF. Bohl claims Selwyn simply failed to recognize nearly ten years of depreciation history preceding the date Selwyn alleges the migration strategy began. Bohl claims that competitive activity began in 1978 and it caused the recent increase of retirements from account 234.

Taking Bohl's presentation at face value indicates to us that we have done a very poor job determining remaining lives for some accounts; and it is obvious that a triennial represcription may not be adequate and Pacific's suggestion that it be done each year should be considered.

Witness Turk for Pacific testified **[*37]** that the NPF, or percent condition, of Pacific's 234 account is 81%, meaning, conversely, only 19% of it has been depreciated. Chart I from Coughlan's Exhibit 447 shows that depreciation reserve based on group plan, straight line, depreciation over a long period of time (18-20 years) becomes constant if no other factors are working on the account. That is, if all of the equipment that is being depreciated lives out its life as predicted when it was first put into service, then the reserve account reaches a constant level. As an example, Chart I shows that if plant growth is static, the undepreciated investment becomes about 58% and stays at that level forever. If the growth rate is 5%, it equals 62%, 10% = 65%, 15% = 68%, and 20% = 71%. If we were to assume a depreciation reserve growth rate of 15% is reasonable for Pacific, the undepreciated investment in account 234 should be at a constant 68%. It is not -- it is 81%. This example indicates that there are about 13% points reserve deficiency in the account; perhaps it is better to say 13% more of the plant investment balance should have been depreciated but was not.

Discussion

The record in this proceeding indicates **[*38]** 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. However, ratepayers should not bear the full cost of increasing the depreciation reserve if Pacific's migration strategy contributed to the resulting increased revenue requirement in ways which would not benefit ratepayers as a group.

Some of the existing stranded investment is certainly attributable to Pacific's marketing practices. We noted in D.93367 that Pacific had embraced the marketing strategies of its parent, AT&T. The evidence is quite clear that there have been early retirements of equipment because of marketing strategies which were designed to secure **[*39]** embedded equipment market customers against competition. Selwyn provided two estimates of the cost attributable to the migration strategy. Both were disputed by Pacific.

We believe that Selwyn's analysis comparing estimated 1980-81 retirements with actual 1980-81 retirements for Account 234 is a reasonable one for purposes of this proceeding. Based on that analysis, $19 million of Account 234 retirements are attributable to Pacific's migration strategy, thus overstating the rate base by understating the reserve in like amount. In essence, $19 million of Pacific's existing rate base is overstated as a result of Pacific's marketing strategy, and yet that rate base is still earning a return.

We find that $19 million of Pacific's rate base should not earn a return from ratepayers. We will order Pacific to remove that amount from rate base, an adjustment which lowers the annual revenue requirement, as determined for purposes of this proceeding, by $3.5 million which allows for 75% of the adjustment to California intrastate, and a net to gross factor of 1.896 and the 12.9% return granted in D.93367. We expect this adjustment to rate base to be included as part of Pacific's pending **[*40]** general rate case proceeding (A.83-01-22).

As noted earlier, one of our problems is the frequency of our depreciation reviews, every three years on a committee basis -- Pacific, the FCC, and our own staff. We believe now this should be done more often. The depreciation rates we use for ratemaking purposes, that is, straight line remaining life, would then be more in line with the actual consumption of Pacific's assets; Pacific recommends a yearly review which may be too often for our staff resources. An alternative we want Pacific, our staff, and the parties to consider would eliminate estimating remaining life for accounts susceptible to group accounting methods such as 234 in favor of maintaining such accounts at an agreed-upon NPF.

This would automatically determine annual depreciation allowances for ratemaking. As an example we canassume an NPF of 70% is reasonable for an account and that, at the beginning of a given year, the NPF is at that level. Additions and retirements to the plant account and net retirements to the reserve account would be made during the year; depreciation for the year would be the amount necessary to bring the NPF to 70%. Safeguards could be built **[*41]** into such a scheme such as an annual review of the target NPF, growth rates, plant additions, retirements, and salvage values.

The two developments which are going to affect what we do in this proceeding and in Pacific's current major rate case are the FCC CI-II decision and the MFJ in the antitrust case. As we understand the Modified Final Judgment as approved by Judge Greene those assets of Pacific which go to American Telephone & Telegraph Company (AT&T) sometime early in 1984 will be transferred at book value based on FCC accounting and not on this Commission's notation reserves we use for ratemaking purposes. This creates a ratemaking problem for AT&T, this Commission, and the FCC and will affect the California payers of interstate and intrastate rates for services furnished by AT&T. This should be carefully considered as we move through divestiture, FCC Docket No. 81-893, and the current Pacific rate case.

We will grant Pacific's request for increased depreciation allowances with the exception of ELG. We, in effect, approved most of the request in RRD-10 in February 1982 and it only remained to determine the proper revenue requirement adjustment in this proceeding. Also, **[*42]** Pacific has been booking most of the request since January 1981 although it is for book purposes and represents no real cash drain such as a corresponding increase in wage costs might.

We are persuaded by the staff's showing that, in the long run, ELG is more costly to the ratepayers with no corresponding benefit to Pacific. Our present straight line remaining life method recovers all of Pacific's investment (even, eventually, any stranded investment) and Pacific, in the meantime, receives a return on its undepreciated investment (rate base) so that, in the long run, Pacific loses nothing. Although it is true that granting ELG along with the other adjustments Pacific proposes could help alleviate what we see as too high an NPF, the amount of help from ELG would be small and does not appear to offset the reduced benefits to ratepayers.

Rate Design

Pacific offered a rate design through its witness G. W. McBee and the staff through witness Emily Marks. Pacific conceded that it would adopt the staff proposal. Marks put in two proposals, one with the ELG revenue requirement and one without. Table 1 is the staff proposal without ELG which we will adopt for this decision; it **[*43]** must be scaled down to comport with the following discussion.

TABLE 1
SUMMARY OF GUIDELINE RATES
BASIC EXCHANGE SERVICE
ZONE USAGE MEASUREMENT SERVICE

BASIC EXCHANGE (Flat Rate)	Present D.93367	Guideline
Business Service		
Individual Line	$14.55	$15.60
2-Party Line	10.75	11.55
4-Party Suburban	11.00	11.80
Farmer Line	4.15	4.35
PBX Trunk	21.75	23.40
Centrex Line	2.20	2.30
Foreign Exchange	15.50	16.55
Residence Service		
Individual Line		
ZUM Areas	7.00	7.60
SMRT Areas	6.70	7.60
Unmeasured	6.70	7.60
2-Party Line	4.75	5.00
4-Party Suburban	4.90	5.00
Farmer Line	2.20	2.35
PBX Trunk		
ZUM Areas	10.50	11.40
SMRT Areas	10.05	11.40

TABLE 1
SUMMARY OF GUIDELINE RATES
BASIC EXCHANGE SERVICE
ZONE USAGE MEASUREMENT SERVICE

BASIC EXCHANGE (Flat Rate)	Present D.93367	Guideline
Unmeasured	10.05	11.40
Foreign Exchange		
ZUM Areas	8.50	9.10
SMRT Areas	8.20	9.10
Unmeasured	8.20	9.10
ZONE USAGE MEASUREMENT		
Initial Period		
One-Minute Units		
Zone 1	3	3
Zone 2	6	6
Zone 3	8	8

We have two matters requiring refunds that we brought over to this decision, the last decision involving rates in these proceedings. n6 These are the $12.8 million dollar adjustment **[*44]** as a result of the stipulation authorized by D.82-05-044 on the rate base adopted by D.93367 and the $3.6 million Economic Recovery Tax Act adjustment ordered by D.82-12-046 retroactive to January 1, 1982 as provided for in D.93850 dated December 15, 1981. We find it most practicable to meld those two refunds with the increase authorized by this decision in the following way. The increase resulting from this decision will go into effect when the amount of the refunds noted above have been equaled by the increased revenues from this decision. Table 2 is an example of how we intend this to work and should serve as a guide for Pacific in an advice letter filing to accomplish our intent. The advice letter filing should reflect the actual number of days involved and appropriate interest as provided for in the following order.

n6 We recognize there is one final decision to be issued in these proceedings; that one involves OII 84 and the matter of inside wiring now consolidated with these proceedings as A.82-10-23. Other than the effect of the stipulation noted in the text on revenue requirement as a result of our decisions on inside wiring writeoffs, revenue changes, if adopted, will be a wash.

[*45]

In devising and ordering the above refund schedule we take note of *California Manufacturers Association v CPUC (1979) 24 C 3d 836* where the court found that rate refunds should be distributed to utility customers in accordance with *PU Code § 453.5* which requires the Commission to order refunds paid to all current utility customers, and, when practicable, to prior customers. However, the court found in that decision that both the history and language of § 453.5 are persuasive that the statutory term "rate refunds," as therein employed, refers to specific amounts held by utilities as rebates from their suppliers and earmarked for customer refunds by prior Commission orders and utility tariffs. Further, that case involved a balancing account adjustment of the rate refunds which would have returned the rebates on a basis that discriminated between business and residential customers. That will not be the case here. We believe the most practicable means of refunding is what we propose above. In the past where we ordered refunds to be made retroactively based on prior billings we have found the process cumbersome, time consuming, and, in some cases, a near impossible task **[*46]** for the utilities with the possibility that some of the refunds due never would get to utility customers, certainly, a process much less than practicable. See *Kenneth Cory, as State Controller, v CPUC (1983) 33 C 3d 522.* The process we propose will put the refunds into the hands of customers immediately and without the adverse effects of a possible refund on the one hand and a certain rate increase on the other.

TABLE 2
(Millions $)

Item	Effective Date	Annual Revenue Adjustment
D.82-05-044	8/29/81	-12.8
D.82-12-046	1/1/82	- 3.6
This Decision	5/1/83 *	** 61.4
	Net Change	+45.0

* For illustrative purposes.

** 19 X 75% X 12.91% X 1.896 = 3.5

64.9 - 3.5 = 61.4

9/81 - 5/83 = 20 mos. X 12.8 / 12 = 21.3

1/82 - 5/83 = 16 mos. X 3.6 / 12 = 4.8 / 26.1

45.0 / 12 = 3.75/mo.

26.1 / 3.75 = 7.0

7.0 months after 5/1/83, the assumed effective date of the rate increase authorized by this decision, rates would be adjusted to produce an increase in revenue of $45.0 million.

In the calculation called for in the order in this decision:

a. Days would be used instead of months.

b. Interest on the two refund orders would be taken into **[*47]** account.

c. Any effective surcharges would be accounted for.

The issue of a rate base adjustment reflecting cost savings from Pacific's PhoneCenter program which was raised by Cities of San Francisco and San Diego will be addressed in a separate decision.

Findings of Fact

1. In Interim D.93367 dated August 4, 1981, the Commission ordered further hearings on the issues of:

a. An appropriate method for allocating to the proper user any net stranded investment as a result of the migration strategy and the establishment of nonregulated operations.

b. Studies to determine the kinds of equipment which may have been retired prior to being fully depreciated and the associated stranded investment.

c. A method for recovering fairly any stranded investment.

d. Depreciation rates used for ratemaking.

2. On February 4, 1982 this Commission adopted Resolution RRD-10 approving new 1981 remaining life rates for Pacific.

3. Further hearings in these proceedings were held in 1981 and 1982 on the issues enumerated in Finding of Fact 1 where all interested parties were afforded the opportunity to appear and be heard.

4. On June 7, 1982 Pacific filed a third amendment to A.59849 **[*48]** requesting the Commission to authorize additional revenues of $69.9 million per year to cover the increases in depreciation expense approved by the Commission in RRD-10 and other changes involving additional applicability of approved rates to other equipment, a change in the periods used for test year account averaging, and adoption of ELG depreciation methods.

5. Pacific is required by this Commission to use straight line vintage group remaining life depreciation for retemaking purposes.

6. Pacific's book depreciation reserve declined from 24% of depreciable plant in 1950 to 19% by the end of 1980.

7. The decline in Pacific's book depreciation reserve as a percent of plant for the terminal equipment accounts is primarily due to earlier than expected retirement of assets.

8. The terms "stranded investment" and "reserve deficiency" are interchangeable and describe an underaccrual of depreciation in past years resulting from earlier than anticipated retirements.

9. Depreciation reserve as a percent of investment tends to stabilize even when the reserve is growing.

10. Although the shortening of asset lives for depreciation purposes through the represcription process recovers **[*49]** total investment, it assigns no responsibility to those customers who do not keep equipment for its average estimated original life nor to Pacific for such premature retirements.

11. The most likely customers to pay the costs of stranded investment caused by premature retirements are those who take service after such retirements.

12. Estimates of the amount of stranded investment on Pacific's books range from $19 to $95.7 million.

13. The record supports the removal of $19 million from Pacific's rate base, an amount which lowers the annual revenue requirement, as determined for purposes of this proceeding, by $3.5 million.

14. Remaining life estimates or represcription for Pacific's assets is now made on a triennial basis after conferences among the Commission staff, Pacific, and the FCC staff.

15. A less than triennial represcription of the lives of Pacific's assets would respond more timely to the rapidly changing technology in the telecommunications industry.

16. The technical staff of the Commission does not oppose Pacific's request for depreciation changes except for the ELG method.

17. When the time value of money is taken into account at the rate of return authorized **[*50]** Pacific in D.93367 the straight line vintage group remaining life method of depreciation is less costly for ratepayers in the long run than the SLELG method.

18. Pacific's request for additional depreciation allowances as put forth in this decision, with the exception of adoption of the ELG method and the $19 million adjustment to rate base to account for stranded investment, are reasonable and should be adopted.

19. The increased revenue requirement to accomplish the additional allowances noted in Finding of Fact 18 is $61.4 million based on the results of operations adopted in D.93367 dated August 4, 1981.

20. The general rate design shown on Table 1 should be used by Pacific in the filing to accomplish the change in rates authorized by this decision.

21. It is most practicable to meld the rate decrease ordered in D.82-05-044 and D.82-12-046 with the increase authorized by this decision into one net increase as shown, for example, on Table 2.

Conclusion of Law

Based on the foregoing findings of fact and under *Public Utilities Code § 454* this Commission may grant Pacific authority to increase rates as provided for in the following order to enable Pecific to earn additional **[*51]** annual revenues of $45 million ($61.4 - 12.8 - 3.6).

SIXTH INTERIM ORDER

IT IS ORDERED that:

1. The Pacific Telephone and Telegraph Company (Pacific) shall perform a calculation of the effective date to increase its revenue requirement by $45 million annually after taking into account the revenue reductions ordered by D.82-05-044 and D.82-12-046 in a manner similar to that shown on Table 2 of this decision and file an original and 18 copies of that calculation with the Commission's Docket Office and all parties 30 days after the effective date of this decision.

2. Pacific shall file with the Commission, 30 days prior to the effective date determined in Ordering Paragraph 1, in conformity with General Order 96-A, revised tariff schedules with rates, charges, and conditions modified in general conformance with Table 1 of this decision and designed to produce an increase in revenue requirement of no more than $45 million based on the results of operations adopted in D.93367 with an adjustment of the present 6.66% surcharge to recognize the larger revenue base to which the surcharge will be applied in the future.

3. Interest on amounts subject to refund shall be computed **[*52]** by applying the Federal Reserve Board Commercial Paper Rate, 3-month prime, published monthly in Federal Reserve Board Statistical Release G-13 with monthly compounding.

4. The rates authorized in this decision shall be subject to refund upon further order of the Commission only on any accumulated reserve in connection with the AAA/AA treatment of accelerated depreciation.

5. No later than 60 days after the effective date of this decision the Commission staff and Pacific shall file a plan, jointly, if possible, for changing the triennial represcription process to a more frequent review.

This order becomes effective 30 days from today.

Dated August 3, 1983, at San Francisco, California.

Legal Topics:

For related research and practice materials, see the following legal topics:
Communications LawBroadcastingRate RegulationCommunications LawTelephone ServicesCellular Services

APPENDIX A
Table 1
SLVG - DETERMINATION OF
AVERAGE SERVICE LIFE

Year a	Surviving Investment b	Weight c	Area d = b X c
1	$1000	1 year	$1000 years
2	900	1 year	900 years
3	800	1 year	800 years
4	700	1 year	700 years
5	600	1 year	600 years
6	500	1 year	500 years
7	400	1 year	400 years
8	300	1 year	300 years
9	200	1 year	200 years
10		1 year	100 years
	Total Area Under Curve =		$5500 years
	Average Service Life =		$5500 years / $1000
		=	5.5 years

[*53]

APPENDIX A
Table 2
SLVG DEPRECIATION ILLUSTRATION
DETERMINATION OF ANNUAL ACCRUALS AND DEPRECIATION RESERVE AMOUNT

Year n	Beg. of Year Investment a #	End of Year Retirements b #	End of Year Investment c = n - b	Annual Accruals d = 0.182 * X a	Depreciation Reserve Net Change e = d - b	Depreciation Reserve End of Year f = e + f **
1	$1,000	$100	$900	$ 182	$82	$82
2	900	100	800	163	63	145
3	800	100	700	146	46	191
4	700	100	600	127	27	218
5	600	100	500	109	9	227
6	500	100	400	91	-9	218
7	400	100	300	73	-27	191
8	300	100	200	55	-45	146

APPENDIX A
Table 2
SLVG DEPRECIATION ILLUSTRATION
DETERMINATION OF ANNUAL ACCRUALS AND DEPRECIATION RESERVE AMOUNT

Year	Beg. of Year Investment	End of Year Retirements	End of Year Investment	Annual Accruals	Depreciation Reserve Net Change	Depreciation Reserve End of Year
n	a #	b #	c = n - b	d = 0.182 * X a	e = d - b	f = e + f **
9	200	100	100	36	-64	82
10	100	100	0	18	-82	0
				$1,000		

Columns a and b are based on retirements following the survivor curve in Table 1.

* Whole Life Depreciation rate = 100% - Average Net Salvage % / Average Life = 100% - 0% / 5.5 years = 18.2%/year

Remaining Life Depreciation Rate (%) = 100 - Future Net Salvage - Depr. Res. % / Average Remaining Life = 100% - 0% - 0% / 5.5 = 18.2%/year

** Prior year

APPENDIX A
Table 3
SLVG WHOLE LIFE DEPRECIATION ILLUSTRATION
DETERMINATION OF ANNUAL ACCRUALS AND
DEPRECIATION RESERVE AMOUNT
ESTIMATED SERVICE LIFE CHANGES AT THE END OF YEAR 3
($000)

Year	Beg. of Year Investment	End of Year Retirements	End of Year Investment	Annual Accruals	Depreciation Reserve Net Change	Depreciation Reserve End-of-Year
n	a #	b #	c = a - b	d = a X rate *	e = d - b	f = e + f **
1	$1,000	$100	$900	$182	$82	$ 82
2	900	100	800	163	63	145
3	800	100	700	146	46	191
4	700	100	600	155	55	246
5	600	100	500	133	33	279
6	500	500	0	111	-	-
7	0	-	-	-	-	-
8	-	-	-	-	-	-
9	-	-	-	-	-	-
10	-	-	-		-	-
				$890		$ -110

[*54]

Columns a and b are based on retirements following the survivor curve in Table 1.

* Depreciation rate used in Column d:

Years 1 - 3: rate = 100% - 0% / 5.5 Years = 18.2%/year

Years 4 - 6: rate = 100% - 0% / 4.5 years = 22.2%/year

** Prior year

APPENDIX A
Table 4
SLVG REMAINING LIFE DEPRECIATION ILLUSTRATION
DETERMINATION OF ANNUAL ACCRUALS AND
DEPRECIATION RESERVE AMOUNT
ESTIMATED SERVICE LIFE CHANGES AT THE END OF YEAR 3

Year n	Beg. of Year Investment a #	End of Year Retirements b #	End of Year Investment c = a - b	Annual Accruals d = a X rate *	Depreciation Reserve Net Change e = d - b	Depreciation Reserve End of Year f = e + f **
1	$1000	$100	$900	$ 182	$82	$82
2	900	100	800	163	63	145
3	800	100	700	146	46	191
4	700	100	600	198	98	289
5	600	100	500	170	70	359
6	500	500	0	141	-359	0
7	0	-	-	-	-	-
8	-	-	-	-	-	-
9	-	-	-	-	-	-
10	-	-	-	-	-	-
				$1000		

Columns a and b are based on retirements following the survivor curve in Chart 1.

* Depreciation rate used in Column d:

Years 1 - 3: rate = 100% - 0% - 0% / 5.5 Years = 18.2%/year

Years 4 - 6: rate = 100% - 0% - 27.38% / 2.57 years = 28.3%/year

** Prior year

[*55]

APPENDIX A

Table 5

SLVG DEPRECIATION ACCRUALS VS. CAPITAL CONSUMPTION

VINTAGE: 3 units of plant at $100 with lives of 5, 10 & 15 years, respectively.

ASL = 5 years + 10 years + 15 years / 3 = 10 years

ASSUME: 0% Salvage

Year n	Beg. Yr. Plant Balance (a)	Retire-ments E.O.Y. (b)	Deprec. Accrual (c)=(a)X10%	Deprec. Reserve (d)	Capital * Consumption (e)	SLVG Reserve Deficiency (f)=(e)-(d)
1	$300		$30	$30	$36.67	$6.67
2	300		30	60	73.33	13.33
3	300		30	90	110.00	20.00
4	300		30	120	146.67	26.67
5	300	$100	30	# 50	# 83.33	33.33
6	200		20	70	100.00	30.00
7	200		20	90	116.67	26.67

Year n	Beg. Yr. Plant Balance	Retire-ments E.O.Y.	Deprec. Accrual	Deprec. Reserve	Capital * Consumption	SLVG Reserve Deficiency
8	200		20	110	133.33	23.33
9	200		20	130	150.00	20.00
10	200	100	20	# 50	# 66.67	16.67
11	100		10	60	73.34	13.34
12	100		10	70	80.00	10.00
13	100		10	80	86.67	6.67
14	100		10	90	93.34	3.34
15	100	100	10	# 0	# 0	0

Year n	Net Plant Balance (E.O.Y.) SLVG Basis (g)=(a)-(d)	Capital Con-sumption Basis (h)=(a)-(e)	Excess Rate Base SLVG Basis (i)=(g)-(h)
1	$270	$263.33	$6.67
2	240	226.67	13.33
3	210	190.00	20.00
4	180	153.33	26.67
5	150	116.67	33.33
6	130	100.00	30.00
7	110	83.33	26.67
8	90	66.67	23.33
9	70	50.00	20.00
10	50	33.33	16.67
11	40	26.66	13.34
12	30	20.00	10.00
13	20	13.33	6.67
14	10	6.66	3.34
15	0	0	0

[*56]

* 1/5 of unit #1 for each of first 5 years; 1/10 of unit #2 for each of first 10 years; 1/15 of unit #3 for each of 15 years.

Reflects retirements at 0% salvage.

APPENDIX A
Table 6
SLELG DEPRECIATION
DEVELOPMENT OF ANNUAL DEPRECIATION RATES

ELG Group	Capital Recovery for Years 1 - 10: 1	2	3	4	5	6	7	8	9	10	Total
1	$100	-	-	-	-	-	-	-	-	-	$100
2	50	50	-	-	-	-	-	-	-	-	100
3	34	33	33	-	-	-	-	-	-	-	100
4	25	25	25	25	-	-	-	-	-	-	100
5	20	20	20	20	20	-	-	-	-	-	100
6	17	17	17	17	16	16	-	-	-	-	100
7	15	15	14	14	14	14	14	-	-	-	100
8	13	13	13	13	12	12	12	12	-	-	100
9	12	11	11	11	11	11	11	11	11	-	100

APPENDIX A
Table 6
SLELG DEPRECIATION
DEVELOPMENT OF ANNUAL DEPRECIATION RATES

	ELG Group	Capital Recovery for Years 1 - 10: 1	2	3	4	5	6	7	8	9	10	Total
	10	10	10	10	10	10	10	10	10	10	10	100
Total Accruals		$ 296	$194	$143	$110	$ 83	$ 63	$ 47	$ 33	$ 21	$ 10	$1000
Average Investment		$1000	$900	$800	$700	$600	$500	$400	$300	$200	$100	
Depreciation Rate		29.6%	21.6%	17.9%	15.7%	13.8%	12.6%	11.8%	11.0%	10.5%	10.0%	

[*57]

APPENDIX A
Table 7
SLELG DEPRECIATION
DETERMINATION OF ANNUAL ACCRUALS AND DEPRECIATION RESERVE AMOUNT

Year	Beg.-of-Year Investment	End-of-Year Retirements	End-of-Year Investment	Depreciation Rate	Annual Accruals	Depreciation Reserve Net Change	Depreciation Reserve End-of-Year
n	a	b	c = a - b	d	e = a X d	f = e - b	q = f + q *
1	$1000	$100	$900	0.296	$296	$196	$196
2	900	100	800	0.216	194	94	290
3	800	100	700	0.179	143	43	333
4	700	100	600	0.157	110	10	343
5	600	100	500	0.138	83	-17	326
6	500	100	400	0.126	63	-37	289
7	400	100	300	0.118	47	-53	236
8	300	100	200	0.110	33	-67	169
9	200	100	100	0.105	21	-79	90
10	100	100	0	0.100	10	-90	0
					$1000		

* Prior year

APPENDIX A
Table 8
SLVG VERSUS SLELG
COMPARISON OF ACCRUALS AND RESERVE

	Annual Depreciation Accruals SLVG	SLELG	Difference	End-of-Year Depreciation Reserve SLVG	SLELG	Difference
Year	a	b	c = a - b	d	e	f = d - e
1	$ 182	$ 296	$ -114	$82	$196	$ -114
2	163	194	-31	145	290	-145
3	146	143	3	191	333	-142
4	127	110	17	218	343	-125
5	109	83	26	227	326	-99
6	91	63	28	218	289	-71
7	73	47	26	191	236	-45
8	55	33	22	146	169	-23
9	36	21	15	82	90	-8
10	18	10	8	0	0	0
Total	$1,000	$1,000	$ 0			

[*58]

APPENDIX A
Table 9
SLVG versus SLELG
COMPARISON OF REVENUE REQUIREMENTS
SLVG

Year	Annual Accruals a	EOY Net Plant b	Capital Costs on Average Net Plant c	Total Revenue Requirement # d = a + c
1	$ 182	$818	$136.35	$ 318.35
2	163	655	110.48	273.48
3	146	509	87.30	233.30
4	127	382	66.83	193.83
5	109	273	49.13	158.13
6	91	182	34.13	125.13
7	73	109	21.83	94.83
8	55	54	12.23	67.23
9	36	18	5.40	41.40
10	18	0	1.35	19.35
	$1,000		$525.03	$1,525.03

APPENDIX A
Table 9
SLVG versus SLELG
COMPARISON OF REVENUE REQUIREMENTS

Year	Annual Accruals e	EOY Net Plant f	SLELG Capital Costs on Average Net Plant q	Total Revenue Requirement # h = e + q	SLVG-SLELG Total Revenue Requirement # l = d - h
1	$ 296	$704	$127.80	$ 423.80	$ -105.45
2	194	510	91.05	285.05	- 11.57
3	143	367	65.78	208.78	24.52
4	110	257	46.80	156.80	37.03
5	83	174	32.33	115.33	42.80
6	63	111	21.38	84.38	40.75
7	47	64	13.13	60.13	34.70
8	33	31	7.13	40.13	27.10
9	21	10	3.08	24.08	17.32
10	10	0	0.75	10.75	8.60
	$1,000		$409.23	$1,409.23	$115.80

[*59]

For the purpose of this example, revenue requirement equals annual accruals plus estimated capital costs on average net plant as defined in Columns c and g.

a = Page 9, Column d

b = Page 9, Column c - Column f

c = b + b * / 2 X 0.15 where b = $1,000 in year 0

e = Page 20, Column e

f = Page 20, Column c - Column g

$g = f + f^{*} / 2 \times 0.15$ where $f = \$1,000$ in year 0

* Prior year

(END OF APPENDIX A)

TAB B

ffi CPUC Ruling Dated 11/24/2004
R02-06-001
(See Marked Page 4)

1. PG&E Testimony in Initial AMI Proceeding (A.05-06-028)
(See Marked Pages 3-4 to 3-5; 4-2 to 4-3; and 5-5)

2. PG&E Testimony in AMI Upgrade Proceeding (A07-12-009)
(See Marked Pages 1-4 and 2-4)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING CALLING FOR A TECHNICAL CONFERENCE TO BEGIN DEVELOPMENT OF A REFERENCE DESIGN, DELAYING FILING DATE OF UTILITY ADVANCED METERING INFRASTRUCTURE APPLICATIONS, AND DIRECTING THE FILING OF RATE DESIGN PROPOSALS FOR LARGE CUSTOMERS

On October 15, 2004, Pacific Gas and Electric Company (PG&E) filed its preliminary advanced metering infrastructure business case analysis in compliance with our July 21, 2004 ruling. San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) filed their preliminary analyses on October 22, 2004. The July 21, 2004 ruling identified numerous scenarios to analyze and assumptions to be described or specified. None of the utilities have fully complied with our directives in the July 21, 2004 ruling although all three have completed much of the analysis that was required.

Our July 21, 2004 ruling had established December 15, 2004 as the date by which each utility was to file an application for a particular advanced metering infrastructure deployment strategy and the associated justification, timing, costs, and cost recovery based on the results of their analysis. PG&E has since filed a motion seeking delay of the application until March 15, 2005. SCE supports the request. After reviewing the preliminary analyses, we conclude that additional analytical work is necessary before the utilities will be ready to file their applications for advanced metering infrastructure deployment. Thus, we move back the filing date for the applications to March 15, 2005.

This delay will have the added benefit of allowing the California Energy Commission to host a technical conference to begin the process of developing open architecture standards for advanced metering infrastructure. In particular, we are focused on the need for a reference design that will accomplish uniform business practices and data exchange standards. Free flow of data (subject to security and privacy concerns, of course) is crucial to the economics of the investment we are considering and the long-term viability of the systems the utilities will consider installing. Ideally, we would like to see national standards for data exchange so that providers of advanced metering communications infrastructure will see the same standards in all venues where they seek to market. This uniformity helps lower costs to consumers everywhere.

As a first step, the California Energy Commission has agreed to host a technical conference on a reference design for uniform business practices and data exchange standards and report back to us on the utilities' progress towards developing such standards by January 30, 2005. The technical workshop may also consider a reference design for meter hardware, if appropriate. The California Energy Commission should provide notice of the technical conference to the service list for this (or successor) proceeding.

By January 12, 2005, the utilities should complete the analysis that was required by our July 21, 2004 ruling that was not included in their October filings. For example, some utilities did not perform analysis of outsourcing funding and implementation approaches as required, include a description of the functionality of the meter and network systems they analyzed and discuss the tradeoffs they made to reach their decision on meter and network functionality, or identify the costs/benefits to customers greater than 200 kW. At a minimum, by January 12, 2005, the utilities should complete, file, and serve the analysis that was required by the July 21, 2004 ruling.

Although the utilities will file new applications, now due March 15, 2005, laying out their preferred advanced metering infrastructure deployment strategy, we expect that the applications be handled in a consolidated fashion. After reviewing the preliminary analyses, we have concluded that in the applications, in addition to its preferred advanced metering infrastructure deployment strategy, each utility should include the benefit-cost results for at least one full and one partial advanced metering infrastructure deployment scenario. The utilities may, at their discretion, collapse the numerous cost categories set forth in the July 21, 2004 ruling into the six larger heading groups but benefits should still be described at the more detailed level required in the ruling. However, the utilities should provide an estimate of the purchase and installation costs of the advanced metering infrastructure system proposed in each scenario by customer class and on a per customer basis (for each class).

We note that SCE's preliminary analysis suggests that SCE will not recommend either full or partial deployment as a result of its analysis. SCE should still file an application on March 15, 2005 that, at a minimum, contains the best full and partial deployment scenarios analyzed and any recommended steps that SCE will take to capture the system and customer benefits that we have identified as coming from deployment of advanced metering infrastructure.

In addition to the elements of the application that we described in the July 21, 2004 ruling and elsewhere in this ruling, we believe that some additional information would be useful to the Commission's analysis of the business case application that will be filed in March. In particular, for each scenario in the application, we direct the utilities to provide:

1. A breakdown of the expected demand response benefits between those customers who currently have meters and those who would receive meters under the proposed deployment plan;

2. The expected values (in addition to the range) of the costs and benefits from the proposed deployment strategy that are the outputs of the Monte Carlo simulation analysis;

3. An analysis of customer bill impacts if customers stay on the default rate assumed in the scenario, assuming customer usage patterns do not change, both with and without fixed meter charges and the AB1X rate constraint;

4. Sensitivity analyses (both high and low) around the capacity and energy values utilized;

5. The annual energy use impacts associated with each rate utilized;[1]

6. The costs assumed for residential control technologies used in the analysis, including smart thermostats and load control switches, and the assumed level of benefits, on a per household basis, associated with use of these control technologies;

7. A clear description of the assumptions regarding accelerated cost recovery, ratebase, and tax treatment of existing metering and communication systems that would be replaced under the utility's proposed deployment of advanced metering infrastructure.

Because deployment of advanced metering infrastructure is a significant cost and operational undertaking, as part of the cost recovery proposals the utilities will present in their applications, we are open to reviewing proposals about how the risks and rewards from deploying these systems should be allocated between ratepayers and shareholders.

By approving the delay to March 15, 2005, the parties will have additional time to review the preliminary data, the utilities will have additional time to complete the analytical work that they did not complete before October 15 and 22, 2004 respectively and reflect the results of the 2004 Statewide Pricing Pilot results and 2004 load impact studies in their analysis, and reflect an open architecture approach to infrastructure deployment. We recognize that this delay means that a decision on deployment of advanced metering infrastructure will not be possible by Summer 2005 as we had hoped.

In addition, it is clear from reviewing the preliminary analyses, that the utilities believe that it will not be cost effective to deploy an advanced metering infrastructure

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[1] In other words, does the tariff structure assumed result in overall reduced energy usage (conservation impact), shift of load (no overall impact), or increased energy usage?

without implementing significant changes to rate design in order to capture potential demand response benefits. Most large customers already have interval meters in place, but the communications and billing infrastructure associated with these meters is not necessarily in place yet. Independent of any Commission decision on their upcoming advanced metering infrastructure applications, the utilities should move immediately to fully utilize and integrate the capabilities of the existing advanced meters installed at large customer premises into their operations.

The March 15, 2005 applications will not contain technical rate design proposals, but clearly the rate design assumptions they utilize will impact the cost benefit analysis. In addition, the parties have pointed out that the Commission's interpretation of Assembly Bill 1X may limit our ability to make significant changes to rates or rate design for all customer classes, should that be desirable, in the near term. We recognize that the rate design framework modifications that are required to achieve maximum benefits from installation of advanced metering infrastructure likely require rethinking the proper default tariff, the objectives of the rate design (maximum price response vs. cost-based pricing), proper planning horizons, and many other complex and difficult issues. Utilizing the most recent cost allocation to customer classes adopted in the utilities' rate design proceedings, we must make it a priority to tackle these issues. A subsequent ruling will lay out our planned timeframe for pursuing rate design changes.

Therefore, **IT IS RULED** that:

1. By January 12, 2005, the utilities shall complete, file, and serve the analysis that was required by the July 21, 2004 ruling.

2. The filing date for the applications for a particular advanced metering infrastructure deployment strategy and the associated justification, timing, costs, and cost recovery is moved to March 15, 2005.

3. The California Energy Commission shall host a technical conference on a reference design for uniform business practices and data exchange standards and report

back to us on the utilities' progress towards developing such standards by January 30, 2005.

4. The utilities shall move immediately to fully utilize and integrate the capabilities of the advanced meters installed at large customer premises into their operations.

Dated November 24, 2004, at San Francisco, California.

/s/ MICHAEL R. PEEVEY	/s/ MICHELLE COOKE
Michael R. Peevey	Michelle Cooke
Assigned Commissioner	Administrative Law Judge

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design, Delaying Filing Date of Utility Advanced Metering Infrastructure Applications, and Directing the Filing of Rate Design Proposals for Large Customers on all parties of record in this proceeding or their attorneys of record.

Dated November 24, 2004, at San Francisco, California.

/s/ FANNIE SID
Fannie Sid

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 insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, *e.g.,* sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074,
TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.

Application No.: ____________________
(U 39 M)
Exhibit No.: (PG&E-5)
Date: June 16, 2005
Witness: James L. Meadows
Jasmin Ansar
Lee V. Jacobs
Jack A. Battin
Paul R. Prudhomme
Daniel R. Pease
Shaun E. Halverson

PACIFIC GAS AND ELECTRIC COMPANY

AMI PROJECT COST BENEFIT ANALYSIS AND RATEMAKING

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
AMI PROJECT COST BENEFIT ANALYSIS AND RATEMAKING

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

BUSINESS CASE RESULTS AND PRESENT VALUE MODEL METHODOLOGY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
BUSINESS CASE RESULTS AND PRESENT VALUE MODEL METHODOLOGY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
BUSINESS CASE RESULTS AND PRESENT VALUE MODEL METHODOLOGY

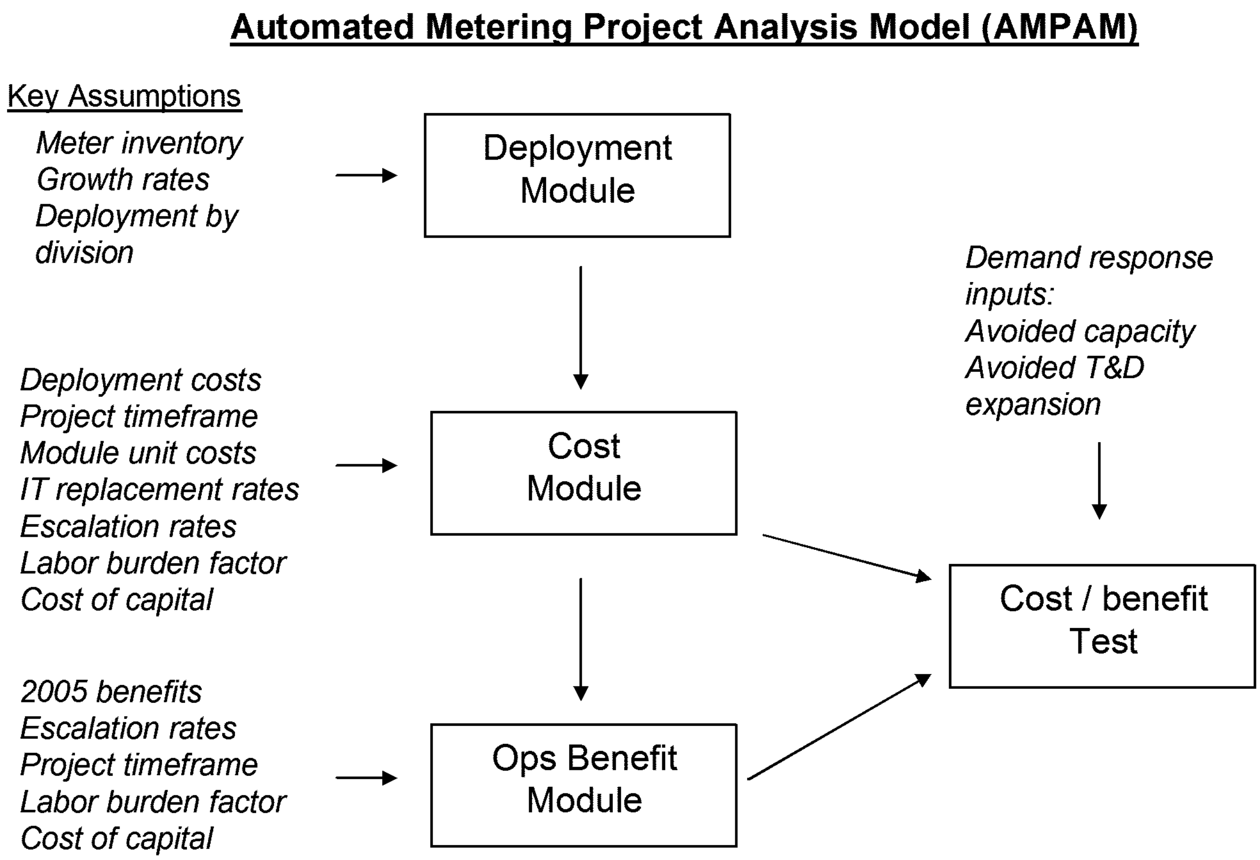
A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) approach to analyze the economics of its proposed Advance Metering Infrastructure (AMI) Project and to summarize the results of the AMI Project business case. PG&E's AMI Project business case includes a detailed analysis of two major elements:

a. A comparison of the present value of estimated costs to fully deploy PG&E's selected AMI technology with the present value of forecast operational benefits resulting from the AMI Project; and
b. An assessment of potential demand response benefits based on PG&E's projections of customer response to demand-based energy programs.

PG&E retained Financial Strategies Group (FSG) to analyze the economics of its AMI Project business case. FSG developed a cash flow based analysis tool referred to as the Automated Metering Project Analysis Model (AMPAM) to provide a quantitative basis for its economic assessment. A summary level illustration of the AMPAM components and methodology is provided in Figure 1-1.

FIGURE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
AMPAM MODEL DESIGN



AMPAM relies on estimated AMI Project cost and benefit data compiled by PG&E and summarized in Exhibits 2, 3, and 4 of this application. The source chapters for the costs are shown in Table 1-1, and the source chapter for the benefits are shown in Table 1-2. FSG applied these estimates to the proposed meter deployment schedule outlined in Exhibit 2. FSG used the effects of meter growth, cost escalation and other factors to calculate the annual costs and benefits over the 20-year asset life of AMI. These annual values were adjusted for tax impacts, and were discounted to a 2005 value using PG&E's tax-adjusted weighted average cost of capital. The economic results, shown on a present value basis, demonstrate that a full AMI Project deployment to all customers in PG&E's service area is the most cost effective strategy for PG&E to pursue.

The following sections of this chapter outline the Present Value of Revenue Requirement (PVRR) methodology used by FSG and describe the assumptions needed to determine the AMI Project cost effectiveness using AMPAM. Each assumption provided for deployment or operations and maintenance is used to derive its impact on PG&E's cost of distribution over the life of the assets. The present value of the resulting revenue requirement for the deployment costs are compared to the present value of the utility operational benefits over the same asset life. The results of the operational PVRR are then compared to the expected value of benefits of a demand response program for the final test of cost effectiveness.

B. Summary of Results

1. Results of PVRR Analysis

AMPAM results indicate a net gap between the present value of the revenue requirements for costs and the present value of the revenue requirements of operational benefits of $201 million.

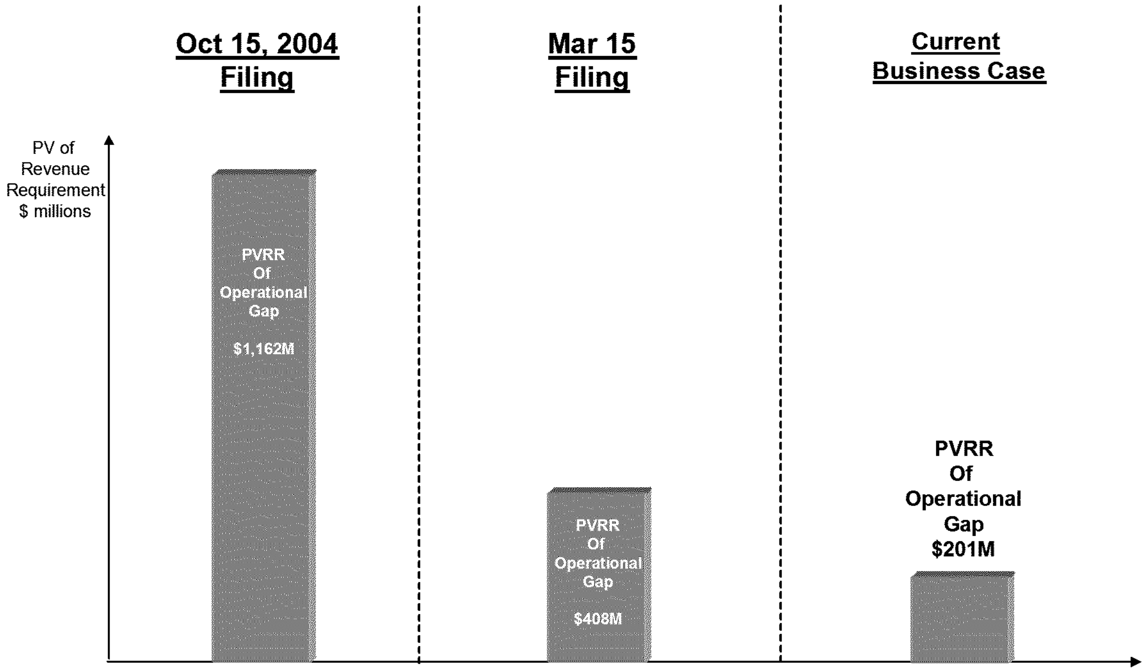
As described in Exhibits 1, 2, 3 and 4, AMI Project deployment costs incorporate the latest cost quotes submitted by the selected vendors along with PG&E's current estimates of its own deployment costs.[1] The update of cost quotes by vendors, as well as PG&E's updates to other assumptions of costs and benefits, yielded an improvement of $207 million in the net operational gap over PG&E's Updated Preliminary AMI Business Case Analysis filed on March 15, 2005, and an improvement of $961 million over the PVRR presented in PG&E's October 15, 2004 Preliminary Business Case Analysis. The previous analyses were based on preliminary cost and benefit assumptions.

Figure 1-2 provides an illustration of the overall reduction in the AMI operational cost/benefit gap resulting from PG&E's ongoing vendor selection process and further refinements in its business case between October 15, 2004, and this application. It is important to note that PG&E is still in negotiations with its selected AMI technology and System Integration

[1] To ensure the completeness of PG&E's project cost-effectiveness test, the total AMI Project costs include the $49.1 million of pre-deployment costs submitted as part of the PG&E's March 15, 2005 AMI Project Pre-Deployment Cost Recovery pleading in Application 05-03-016.

vendors, thus, PG&E anticipates that the actual costs will vary somewhat from those estimated herein.

FIGURE 1 - 2
PACIFIC GAS AND ELECTRIC COMPANY
OPERATIONAL GAP
THE EVOLUTION OF THE AMI PROJECT BUSINESS CASE



2. Total Cost and Benefits

Table 1-1 provides a summary of estimated AMI Project costs between 2005 and 2010 (described in Exhibits 1 through 4). This table also includes a summary of the PVRR of total AMI Project deployment costs, forecast Operations and Maintenance (O&M) costs over the 20-year asset life period. As shown in Table 1-1 the total costs for full AMI Project deployment have a PVRR of $2,227 million. Table 1-2 provides a summary of estimated AMI benefits in terms of the annualized benefit at full AMI implementation described in Exhibits 2 and 3. This table also includes a summary of the PVRR of total AMI benefits over the 20-year asset life period. The total benefits have a PVRR of $2,026 million. The business case estimate includes a PVRR of $1,846 million of deployment-related costs, such as meters, networks, Information Technology (IT) hardware and software, a PVRR of operations and maintenance costs of $381 millionand PG&E's

forecast of total quantifiable PVRR of operational benefits of $2,026 million. The forecast operational benefits exclude any customer demand response benefits. The estimated costs minus the forecast operational benefits yield the current PVRR operational gap of $201 million.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATED AMI PROJECT COSTS

Line No.	Cost Category	Estimated Costs 2005-2010 ($ in millions)	PVRR ($ in millions)(a)	Reference
1	Project Management Costs	$85.6	$87.2	Exh. 1, Chapter 2
2	Risk-Based Allowance	128.8	135.0	Exh. 1, Chapter 2
3	Meters and Modules	628.3	862.1	Exh. 2, Chapter 1
4	Network Materials	64.4	77.0	Exh. 2, Chapter 1
5	AMI Operations	30.0	82.2	Exh. 2, Chapter 1
6	Interface and Systems Integration	115.9	196.3	Exh. 2, Chapter 2
7	Interval Billing System	83.5	107.1	Exh. 2, Chapter 3
8	Meters/Modules Installation	254.4	287.4	Exh. 2, Chapter 4
9	Electric Network and WAN Installation	47.2	54.6	Exh. 2, Chapter 4
10	Gas Network and Other Installation	11.3	13.9	Exh. 2, Chapter 4
11	Meters/Modules QA Sample Testing	2.8	2.3	Exh. 2, Chapter 4
12	Meter Operations Costs	38.2	172.4	Exh. 3, Chapter 3 workpapers
13	Customer Contact-Related Costs	26.2	33.0	Exh. 3, Chapter 4
14	Customer Exceptions Processing	4.9	4.1	Exh. 3, Chapter 5 workpapers
15	Marketing and Communications	20.4	22.5	Exh. 4, Chapter 2 workpapers
16	Customer Acquisition	53.3	44.0	Exh. 4, Chapter 3 workpapers
17	Other Employee-Related Costs	21.9	45.7	Calculated, See paragraph D-3.
18	Total Estimated Project Costs (*Totals subject to rounding error*)	$1,617.0(b)	$2,226.7	

(a) Includes pre-deployment costs of $49 million requested in A.05-03-016.

(b) Includes $1,470 million of deployment costs and $147 million of operations and maintenance expenses. The $1,470 million of deployment costs consists of $1,259 million of capital expenditures and $211 million of expenses.

TABLE 1-2
PACIFIC GAS AND ELECTRIC COMPANY
ESTIMATED AMI PROJECT BENEFITS

Line No.	Benefit category	Annualized Benefit After Implementation (2005 $ million)	PVRR ($ in millions)	Reference
1	Operational Meter Reading	$86.2	($1,085.2)(a)	Exh. 3, Chapter 1
2	Electric Transmission and Distribution	12.8	(179.1)	Exh. 3, Chapter 2
3	Meter Operations	7.0	(104.2)	Exh. 3, Chapter 3
4	Customer Contact	2.7	(40.3)	Exh. 3, Chapter 4
5	Billing Benefits	18.6	(218.3)(a)	Exh. 3, Chapter 5
6	Gas Transmission and Distribution	1.2	(10.2)	Exh. 3, Chapter 7
7	Reduced Software License Expense	5.0	(47.8)	Exh. 2, Chapter 3
8	Remote Turn-On/Shut-Off	11.5	(103.1)(a)	Exh. 2, Chapter 4
9	Other Employee-Related Costs	18.9	(220.7)	Calculated, See paragraph D-3.
10	Total Annual Benefit	$163.8	($2,008.8)	
11	Reduced Equipment Replacement (2011 $)	8.5	(10.2)	Exh. 3, Chapter 1
12	Deferred Meter Testing	1.6	(7.0)	Exh. 3, Chapter 3
13	Total One-Time Benefits	$10.1	($17.2)	
14	Total Benefits (*Totals subject to rounding error*)		($2,026.0)	

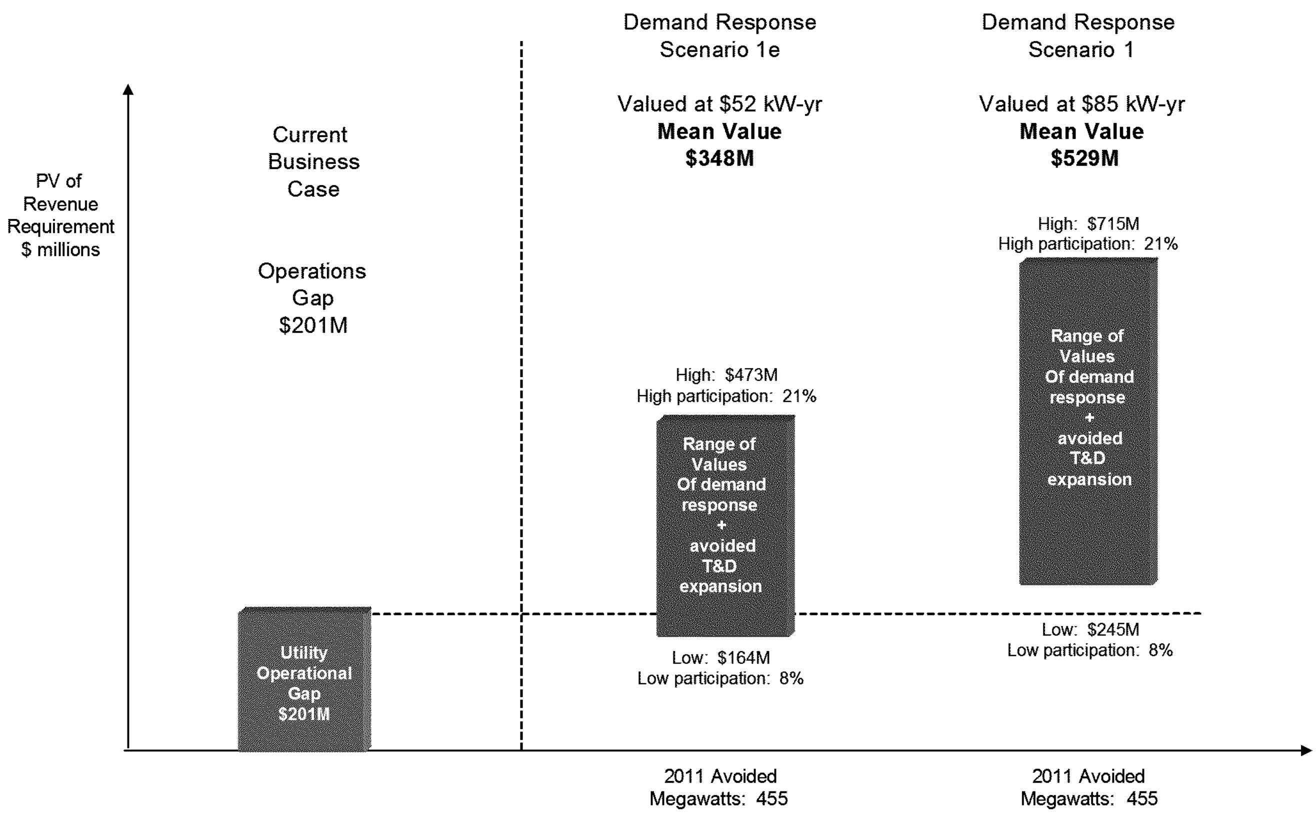
(a) PVRR totals for these benefits are net of severance costs discussed in Exhibit 3, Chapter 6. PVRR values in parentheses means a reduction in PG&E's revenue requirement.

In addition to the operational benefits summarized in Table 1-2, PG&E expects the AMI Project will result in savings derived from customer response to demand response tariffs and programs. As discussed in Exhibit 4, customer demand response savings are uncertain. PG&E analyzed various demand response scenarios and currently forecasts demand response benefits as a range of benefits with a mean value of $348 million or $529 million, depending on the cost of avoided capacity assumption. As described in Exhibit 4, PG&E's demand response analyses have two main drivers—the customer participation rates and the avoided cost of capacity.

Figure 1-3 compares PG&E's projected operational gap against the benefit of demand response calculated with two possible values of avoided capacity cost. In Exhibit 4, Chapter 4, PG&E developed a range of avoided generation capacity costs based on the net capacity cost of alternative supply and demand-side resources. In Figure 1-3, PG&E uses the low end of that range, a levelized rate of $52 per kilowatt (kW)-year based on the net cost of new combustion turbine capacity, and a levelized $85 per kW-year cost provided in Appendix B of the July 21, 2004 Administrative Law Judge and Assigned Commissioner Ruling. The $85 per kW-year rate is lower than the net cost of capacity from other preferred demand-side alternatives shown in Exhibit 4, Chapter 1.

Figure 1-3 demonstrates that either valuation, along with other assumptions, produces significantly higher value of demand response than the amount needed to cover the PVRR of the projected operational gap of $201 million.

FIGURE 1-3
PACIFIC GAS AND ELECTRIC COMPANY
OPERATIONAL GAP VS. DEMAND RESPONSE VALUES



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C. Analytical Methodology

1. Process

FSG's analysis examined the estimated costs and forecast benefits of PG&E's proposed AMI Project, as measured in terms of the PVRR. The PVRR methodology is a specific example of the more general Discounted Cash Flow (DCF) analysis. DCF analysis is the standard financial tool used to evaluate any project involving expenditures and receipts that occur over a number of years. DCF involves determining the relevant cash outlays and cash receipts on a year-by-year basis and then applying an appropriate discount factor to equalize the value of these cash flows to a single time period.

The PVRR methodology inherent in AMPAM takes into account the tax effects that expenditures for capital assets (with an expected useful life of more than one year) or common expenses have on rates. PG&E has historically applied the PVRR methodology used here in AMPAM to evaluate other possible project proposals.

The major assets to be deployed in the AMI Project have an expected life of 20 years. AMPAM calculates the costs and benefits associated with the deployment of these assets over the expected 20-year life. As depicted in Figure A-1 in Appendix A, the model tracks the AMI assets installed in 2006 until 2025, assets installed in 2007 are tracked until 2026, and so forth, until the final conversion year of 2010 is tracked through 2029. Deployment costs are combined with on-going operations and maintenance requirements to describe the total system costs over the 20-year asset life. One-time (and/or limited-time) operational benefits are combined with annual benefits, recurring each year after AMI deployment, to create the forecasted total benefits of the AMI Project. Each of these cash streams is then adjusted to present value terms using PG&E's cost of capital.

Finally, the difference between the present value of operational benefits and the present value of system deployment and annual operating costs equals the operational net gap. The operational net gap is compared to the present value of the demand response benefits, as described in Exhibit 4, to complete the cost/benefit analysis of the AMI Project.

2. Model Architecture

Figure 1-1 depicts the overall architecture of AMPAM and the cost and benefit source assumptions for the model. The three major sections of AMPAM are the Deployment Module, the Cost Module and the Benefits Module. The Deployment Module uses a detailed month-by-month and division-by-division[2] schedule of AMI meter deployment over the five-year plan. PG&E projects its AMI Project deployment will be completed by December 2010. The output of the Deployment Module is then used by the Cost Module and the Benefits Module in calculations that extrapolate the costs and benefits over the 20-year asset life in the analysis.

3. Costs and Benefits

Exhibits 1 through 4 detail the assumptions to AMPAM provided by PG&E subject matter experts. FSG used these inputs in the Deployment Module to reflect a detailed month-by-month and division-by-division schedule of AMI meter deployment. For the Cost Module, PG&E subject matter experts provided specific unit costs to purchase meters and modules, to retrofit existing meters with modules, to install and maintain these meters, etc. FSG compiled the estimated cost data and other assumptions regarding the materials costs, labor, systems, communications links and others and input this data to AMPAM.

FSG combined the deployment costs with the unit cost assumptions to calculate the annual capital and expense costs of the AMI Project. AMPAM also calculates the incremental costs of equipping future customer growth with AMI functionality and the operations and maintenance expenditures required through the 20-year asset life. These deployment and O&M costs are detailed in Table A-2 in Appendix A.

Benefits assumptions included in AMPAM were based on the testimony provided in Exhibit 2 and 3. PG&E's benefit witnesses indicated when the benefits would accrue and the projected value of benefits at full AMI Project deployment. AMPAM then calculates the annual value of benefits for the 20-year asset life, adjusted for the percentage of meters activated and remaining in service. PG&E estimates the AMI meter activation date will

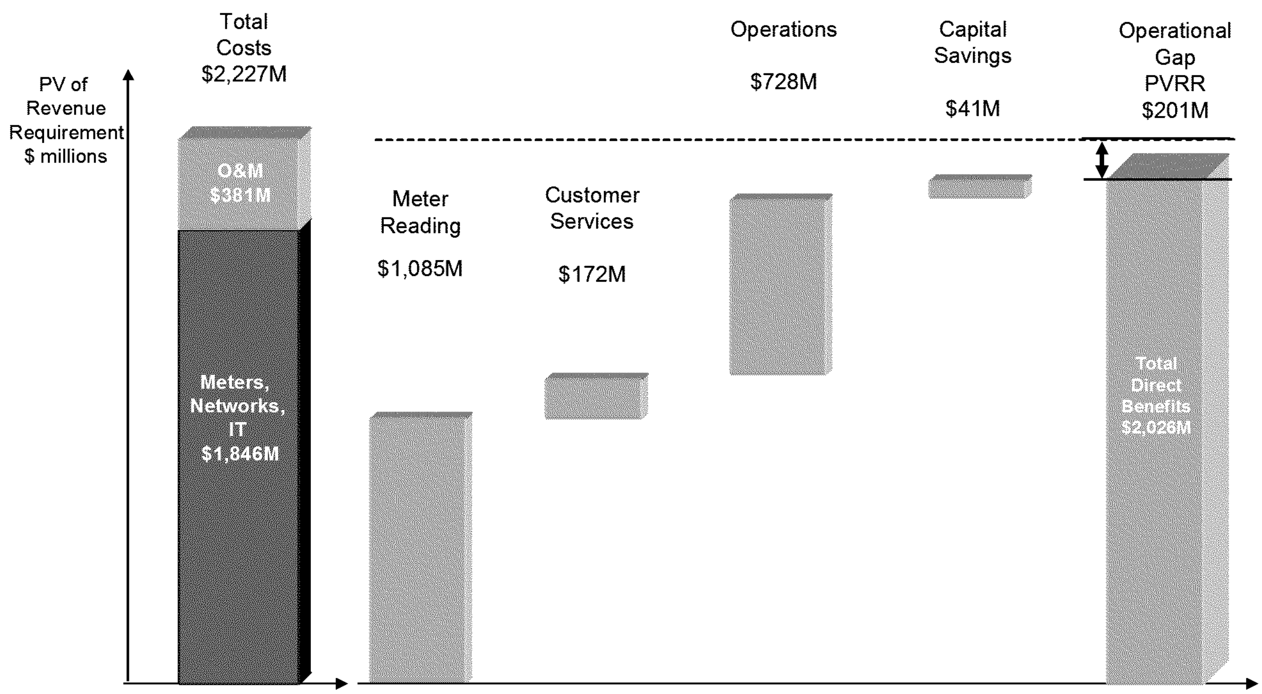
[2] PG&E's service area is divided among 18 geographic operating divisions.

occur approximately three months after meter installation. The operational date of the AMI Project is estimated to be July 1, 2006.

FSG combined escalation rates, loading factors, and the deployment of meters by division in AMPAM to estimate the annual amount of benefits projected by PG&E through the 20-year asset life. PG&E subject matter experts also provided assumptions on the expected escalation in labor rates, the frequency of employee turn-over in certain job classifications, and the expected cost of retraining or severance for displaced employees.

The detailed amount and timing of these benefits are illustrated in Table A-3 in Appendix A.

FIGURE 1-4
PACIFIC GAS AND ELECTRIC COMPANY
OPERATIONAL GAP



4. Discussion of Operational Gap vs. Demand Response Values

Figure 1-4 illustrates that 91 percent of the cost of the AMI Project is paid for over time through operational cost savings. The remainder of the cost savings shown in the analysis derives from the projected longer-term procurement, transmission and distribution capacity savings achieved through the demand response benefits described in Exhibit 4. Those savings are dependent on customer response and carry a higher degree of uncertainty. Therefore, they are expressed as a possible range of benefits that have a mean value of $348 million (based on a $52 kW-year avoided capacity assumption) at the low end of the avoided cost valuation range. The mean value of demand response savings supports PG&E's conclusion that the AMI Project is cost effective, because it is greater than the net operational gap.

Tables 1-3 and 1-4 summarize, at two different avoided capacity valuations, the total value of demand response, as discussed in detail in Exhibit 4:

TABLE 1-3
PACIFIC GAS AND ELECTRIC COMPANY
VALUE OF DEMAND RESPONSE – $85 KW-YEAR

Line No.	Benefit category	Mean PVRR ($ in millions)	Low PVRR ($ in millions)	High PVRR ($ in millions)	Reference
1	Demand response, Gross TRC Benefits – Base Case @$85 kW-year	($460)	($210)	($622)	Exh. 4, Chapter 5
2	T&D Capacity Benefits	(69)	(35)	(93)	Exh. 4, Chapter 6 workpapers
3	Total Demand Response	($529)	($245)	($715)	

TABLE 1-4
PACIFIC GAS AND ELECTRIC COMPANY
VALUE OF DEMAND RESPONSE – $52 KW-YEAR

Line No.	Benefit category	Mean PVRR ($ in millions)	Low PVRR ($ in millions)	High PVRR ($ in millions)	Reference
1	Demand response, Gross TRC Benefits – Scenario 1e @$52kW-year	($279)	($129)	($380)	Exh. 4, Chapter 5
2	T&D Capacity Benefits	(69)	(35)	(93)	Exh. 4, Chapter 6 workpapers
3	Total Demand Response	($348)	($164)	($473)	

D. Detailed Assumptions Included in AMPAM

1. Escalation Factors

PG&E used the average utility labor wage increase forecast for 2005-2011, as derived from industry sources,[3] to derive an escalation factor of 3.28 percent for PG&E labor. No escalation was included in the capital cost of AMI meters, modules or network equipment, nor in the outside contracted labor.

2. Meter Growth Rates

PG&E provided meter growth rates by year, by climate zone, and by class of meter. Electric meters are growing at an average of 1.5 percent. Gas meters are also growing at an average of 1.5 percent.[4]

3. Other Employee-Related Expenses

Other employee-related costs are expenses that are included as a burden on labor or as an additional benefit to labor savings, and are applied to straight-time internal labor. The items included in this benefit are pensions, post-retirement medical and life insurance benefits, long-term disability, workers compensation expense, and other miscellaneous costs per employee. The factor used in this analysis, based on 2004 reported results, is 23.42 percent.[5]

4. Project Timeframe

AMPAM is based on a 20-year asset life for the meters, modules, and other capital assets purchased for the AMI Project. This life span is based on representations made by the equipment vendors and analyzed by PG&E

[3] Forecasts of labor escalation rates were developed using extracts of forecasts of utility employee wage increases from Global Insight's (1) Utility Cost Information Service (UCIS). UCIS forecasts wage and salary increases for utility service workers; managers and administrators; and utility professional and technical workers. These projections were drawn from the first quarter 2005 UCIS forecast release. These labor escalation rates are consistent with those that PG&E's intends to file in its 2007 General Rate Case NOI. PG&E has used the Global Insight forecast in many regulatory proceedings.

[4] Meter sets growth forecast is based on extracts of projections of building activity provided by the California Building Industry Association (CBIA), Economy.com and Global Insights.

[5] Based on PG&E's 2004 third-party billing rates for non-burden benefits and insurance and casualty expenses.

subject matter experts. The analysis assumes each AMI Project meter module will have a 20-year life. Thus, meters placed in service during 2010 have a proportional amount of operational costs and benefits through and including 2029. The annual amount of cash flows through 2029 is discounted back to 2005 dollars by AMPAM.

5. Weighted Average Cost of Capital

FSG discounted the present value calculation of projected cash flows of operational costs, operational benefits, and demand response benefits to 2005 values using PG&E's weighted average cost of capital (WACC) of 7.6 percent.[6] The after-tax WACC used in AMPAM is based on the allowed rate of return for PG&E of 8.77 percent, adjusted for the after-tax cost of debt.

E. Alternatives Examined

1. Partial Deployment

PG&E studied the cost effectiveness of an AMI Project deployment for a subset of its customers—a partial deployment case—in previous business case presentations.[7] The partial deployment case focused on deployment for a subset of PG&E's customers in the warmest portions of PG&E's service territory. Due to the extensive communication network and systems infrastructure necessary regardless of the number of AMI devices installed, and the fact that some of the expected operational benefits would not be realized unless full deployment is reached, the partial deployment scenario does not produce the best results for customers.

2. Other Alternatives

In addition to the partial deployment alternative, PG&E considered multiple AMI technology, deployment, installation labor, vendor selections,

[6] In Decision 04-12-047, the CPUC approved PG&E's cost of capital at a pre-tax rate of 8.77 percent for 2005. This pre-tax rate is adjusted to an after-tax rate of 7.6 percent (rounded to the nearest tenth). This calculation was explained in Section B.2, Table 11, of PG&E's Updated Preliminary AMI Business Case Analysis filed on March 15, 2005.

[7] PG&E's discussed the partial deployment case in Section II.C. and Appendix C of PG&E's March 15, 2005 Updated Preliminary AMI Business Case Analysis.

and other strategies before determining the preferred case articulated in this application (discussed in Exhibit 2). PG&E believes that the preferred case presented here is the best alternative and will produce the best results for customers.

3. Sensitivities

Key assumptions used in the analysis were tested through sensitivity analysis to determine the potential impact on PVRR and the operational gap. The impact is summarized in Table 1-5 below.

TABLE 1-5
PACIFIC GAS AND ELECTRIC COMPANY
SENSITIVITY IMPACT ON OPERATIONAL GAP

Line No.	Variable tested	Sensitivity	Impact to operational gap/revised PVRR
1	Meter Reading Benefit	Two-month delay in release of meter readers	+ $21M / $223M
2	Customer Billing Benefit	One-year delay in realizing benefit	+ $5M / $206M
3	AMI Operations	AMI meter modules fail 50% more often	+ $3M / $204M
4	Interval Billing	Interval billing costs 30% more to implement	+ $24M / $225M

F. Project Plan Timing and Expenditures

As stated in Exhibit 2, Chapter 4, PG&E's plan reflects expeditious deployment beginning in 2006 and project completion by December 2010. The expenditure timeline is included in Appendix A, Table A-1.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

COST RECOVERY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
COST RECOVERY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
COST RECOVERY

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) proposal for cost recovery, including recognition of benefits in the form of offsets to the Advanced Metering Infrastructure (AMI) Project costs, for the Project. In this application, PG&E requests ratemaking treatment for all AMI Project costs for the 2006-2009 period.

Specifically, PG&E proposes the following regulatory ratemaking treatment for AMI Project costs and benefits:

ffi Rates will be set initially to recover forecast project costs, with true-up to actual costs achieved through the proposed new balancing accounts;

ffi The California Public Utilities Commission (CPUC or Commission) will review forecast costs in this application, and as a result of that review, these forecast costs will be deemed reasonable and will not be subject to after-the-fact reasonableness review. If actual costs exceed the forecast, then PG&E proposes to file for recovery of the difference through a traditional after-the-fact reasonableness review filing;

ffi Benefits or incremental cost reductions will also be reviewed in this proceeding, and pre-approved forecast benefits will be incorporated into rates through balancing accounts as project milestones are met;

ffi Rate components covering this AMI Project will be revised annually in the Annual Gas True-up and Annual Electric True-up advice letters, or as otherwise authorized by the Commission.

PG&E believes this proposal fairly balances risks between shareholders and customers, while allowing the project to proceed in a timely manner, consistent with Commission direction. PG&E is committed to the AMI Project, and is willing to take on some risk to ensure project implementation. By agreeing to credit forecast benefits as meters are activated and when milestones are achieved, PG&E assumes the risk of achieving these substantial cost reductions. Thus, customers will be assured of receiving pre-approved benefits as long as the project proceeds and meters are activated. Furthermore, with this proposal, PG&E's shareholders will also receive assurance of cost recovery in a timely manner. Timely recovery of costs is one of the most important factors affecting credit quality and capacity, and the ability of PG&E to carry out its obligation to serve its customers.

This chapter describes, in detail, the proposed balancing account mechanisms for PG&E's cost recovery and benefit recognition. In addition, this chapter describes the relationship of this proposal with the cost recovery mechanism of PG&E's Pre-deployment Cost Application (A.05-03-016), the AMI Memorandum Accounts Advice Letter 2632-G/2664-E filed on May 13, 2005, the AMI Business Case, PG&E's next General Rate Case (GRC) (scheduled to be filed later this year), and future proceedings. This chapter will also outline the benefit calculation and describe when benefits will begin to accrue in the proposed balancing accounts.

B. Interaction With Other Proceedings

PG&E's proposals in this application interact with various other current or anticipated CPUC proceedings.

1. Pre-deployment Cost Application (A.05-03-016)

PG&E filed an application for recovery of pre-deployment costs for the AMI Project (A.05-03-016) on March 15, 2005. In that filing, PG&E requested cost recovery of up to $49 million in pre-deployment expenditures for the initial stage of the AMI Project, which must occur prior to the deployment phase described in this application.

In this application, PG&E is seeking rate treatment for additional pre-deployment activities[1] beyond those requested in Application 05-03-016, to allow for the completion of the pre-deployment or Year 0 phase. As shown in Exhibit 5, Chapter 5, PG&E is asking that the revenue requirements for these additional pre-deployment costs, covering pre-deployment activities in 2006, be included in the rates PG&E requests

[1] In PG&E's AMI Pre-deployment Cost Application (A.05-03-016) filed on March 15, 2005, PG&E stated that in its full AMI Project Application, "PG&E may also seek additional interim funding for any additional pre-deployment costs or other Project costs necessary to prevent delay in an AMI Project." (lines 22-27, p. 4-2)

here, and that the costs and revenues for those pre-deployment activities be recorded in the balancing account mechanisms described in this chapter.

2. AMI Memorandum Accounts Advice Letter 2632-G/2664-E

On May 13, 2005, PG&E filed the AMI Memorandum Accounts Advice Letter 2632-G/2664-E to establish two memorandum accounts to record and recover AMI Project costs.[2] PG&E took this action in order to preserve future cost recovery, pending CPUC decisions in Application 05-03-016 and this docket. Upon approval of Application 05-03-016, the balances of the AMI memorandum accounts, up to the approved expenditure level, will be recovered in the cost recovery mechanism outlined in Application 05-03-016.

PG&E requests that these AMI Memorandum accounts be closed upon approval of the application herein, and that any remaining balances be recovered through the cost recovery mechanism proposed in this chapter.

3. General Rate Case

PG&E will file its next GRC for rates recovering base costs in 2007 through 2009, later this year. Because the Commission will not have had time to review and rule on this application before the 2007 GRC is filed, the GRC forecast will reflect neither costs nor benefits expected as a result of the AMI Project. All incremental base costs and benefits (or decremental costs) from the AMI Project for the period 2006 through 2009 will be dealt with in this application. In this way, neither costs nor benefits will be double counted and all AMI Project base costs and benefits can be examined together in this proceeding. For the remaining deployment year of 2010 (or thereafter if deployment is delayed), PG&E may seek to extend this cost recovery mechanism or it may address it in its more traditional recovery request in the 2010 GRC.

C. Cost Recovery Proposal

As described in Exhibit 1, Chapter 1, in this application, PG&E is seeking authority to proceed with full deployment of an AMI Project. To begin this deployment phase, PG&E requests that the Commission establish rates to begin

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[2] The CPUC has issued a draft resolution on this advice letter, scheduled for a vote on the CPUC's June 30 agenda. If adopted as written, the resolution would approve the establishment of these accounts.

recovering the cost of the AMI Project. As explained more fully in Exhibit 1, Chapter 2, to begin the actual project work, PG&E must sign contracts with and make commitments to various vendors for a substantial percentage of the total project costs. To make these contractual commitments, PG&E must have regulatory authorization both to proceed with the AMI Project and to collect project costs from customers. In addition, the investments in the AMI Project become used and useful and begin service as the equipment is installed, and not at the end of the AMI Project. If cost recovery is deferred, interest will compound and this will increase the total cost of the AMI Project unnecessarily.

PG&E proposes that initial rates for the project be set based on the forecast of costs for Years 0 and 1 not covered by Application 05-03-016 (as shown in Exhibit 5, Chapter 5), and that these costs be included in the total gas and electric distribution rates charged to customers. Although initial rates would be set based on this forecast, PG&E proposes that customers ultimately pay the actual costs of the project, and not the forecast costs. PG&E proposes to create new regulatory gas and electric balancing accounts—the Advanced Metering Infrastructure Balancing Accounts for Gas (AMIBA-G) and Electric (AMIBA-E)—to true-up actual costs with actual revenues received, as well as to capture the benefits achieved through the AMI Project (see next section for benefit discussion). Draft preliminary statements for the AMIBA-G and AMIBA-E accounts proposed herein are attached in Appendix B.

Upon Commission approval of this application, PG&E will file an advice letter for approval of the preliminary statements and to include in rates the forecast AMI gas and electric revenue requirements for all AMI project costs for Years 0 and 1 not covered by Application 05-03-016. The gas and electric forecast revenue requirements are shown in Exhibit 5, Chapter 5, Table 5-2. In Exhibit 5, Chapters 6 and 7, Appendix F and Table 7-1 show the electric and gas rate impacts, respectively, resulting from the forecast 2006 AMI Project revenue requirement in rates.

Table 5-2 also reflects PG&E's incremental 2007-2009 AMI Project revenue requirements, for future recovery in gas and electric distribution rates. For years 2007 through 2009, PG&E will recover the adopted forecast AMI Project revenue requirements combined with the projected year-end balance recorded in the AMIBA in gas and electric rates as part of the Annual Gas True-up and

Annual Electric True-up advice letters, or as otherwise authorized by the Commission. Exhibit 5, Chapters 6 and 7, present the projected electric and gas rate impacts, respectively, resulting from the forecast 2007-2009 AMI Project revenue requirements in rates.

Finally, for illustrative purposes, PG&E provides forecast AMI annual revenue requirements in its workpapers supporting Exhibit 5, Chapter 5, for the period 2010-2011 based on PG&E's full AMI Project deployment proposal. However, recovery of those revenue requirements is not requested at this time. PG&E will request recovery for the 2010-2011 revenue requirements either through an extension of the mechanism proposed in this proceeding, through its 2010 GRC, or through another mechanism available to PG&E at that time.

1. Monthly Calculation

As described in detail in the specific tariff language in Appendix B, each month, PG&E will record the following items into the AMI balancing accounts:

1. Capital-related revenue requirements (debit), calculated on actual recorded plant additions;
2. Actual O&M costs (debit), calculated on recorded expenses;
3. Calculated benefits (credit), as described below; and
4. Actual AMI Project revenues (credit), from rates set to recover the revenue requirements approved in this proceeding.

2. Cost Reasonableness

PG&E requests that the Commission find AMI Project costs to be reasonable so long as the actual cost of the AMI Project is equal to or less than the cost estimate proposed herein. If, however, actual costs exceed the adopted cost estimate, then PG&E proposes to seek recovery of the difference through a traditional after-the-fact reasonableness review process. The AMI Project costs would still be subject to review and verification to ensure that recorded expenditures were correctly assigned to AMI Project activities.

This approach is similar to the one adopted by the Commission for PG&E's Diablo Canyon steam generator replacement project in Decision 05-02-052. As explained in Exhibit 1, Chapter 2, PG&E has undergone a rigorous process of obtaining proposals for the AMI Project that gives it a high degree of confidence in many of the cost elements. By reviewing both PG&E's process and the cost estimates presented in this application, the CPUC can assure itself of the reasonableness of PG&E's project management and of the cost estimates themselves. The CPUC can therefore state its intention, at the conclusion of this proceeding, of not conducting an after-the-fact reasonableness review as long as costs are within the limit evaluated here. Such an assurance is an essential part of the timely cost recovery needed to ensure PG&E's credit quality.

D. Benefits Recognition Proposal

PG&E proposes to recognize benefits resulting from the AMI Project monthly, as meters are activated and project milestones are achieved. Exhibit 5, Chapter 1, details the benefits or cost reductions PG&E forecasts from the AMI Project. PG&E is confident enough in these benefits to propose crediting them to customers without true-up to actuals. As long as these forecast benefits are linked to achieving actual project deployment milestones, PG&E proposes to credit them when the milestones are reached. This way, customers are assured of benefits when the project is implemented.[3]

Most of the benefits forecast by PG&E and shown in Exhibit 5, Chapter 1, are proportional to the number of meters installed and activated. Through 2009, benefits that accrue in proportion to meter activation average $1.2832 per activated meter per month. For these benefits, PG&E will calculate the monthly benefits to be recorded in the balancing accounts by multiplying the actual number of activated meters by $1.2832 (monthly calculation A, Appendix C). Two benefit categories, however, are not proportional to overall meter activation. The first category, interval meter benefits, is proportional not to total meter activation but to conversion of interval meters to the AMI system, as explained in Exhibit 3, Chapter 5. These benefits average $0.0821 per converted interval meter per month. For this category, PG&E will calculate the monthly benefits to

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[3] As noted in Exhibit 5, Chapter 5, demand response-related benefits (avoided procurement, transmission and distribution) are not included in PG&E's net revenue requirements since these benefits are dependent on customer behavior and should not be viewed as utility cost savings unless they materialize in the future. To the extent these savings occur, they will be reflected in customer rates at that time through future GRCs and other filings.

be recorded in the balancing accounts by multiplying the actual number of converted interval meters by $0.0821 (monthly calculation B, Appendix C). Finally, benefits for reduced software licensing expenses are related not to meters but to the upgrade of PG&E's customer care and billing system (CC&B), as explained in Exhibit 2, Chapter 3. These costs will be avoided in two stages. Starting in January after the completion of Phase 3 of the CC&B system, PG&E expects to stop paying for certain software licenses supporting the former CC&B system. These savings will equal $116,667 per month and will continue for the remainder of the project. In addition, beginning in October following the completion of Phase 3 of the CC&B system, an additional software license will expire, and from that point on, software license savings will total $5 million per year or $416,667 per month through to the end of 2009, the period covered by this application. These specified benefits will be credited at the monthly rate once the milestone of completing Phase 3 of the CC&B system is completed (monthly calculation C, Appendix C).

The method of allocating the benefits to the AMIBA-G or AMIBA-E is described in Exhibit 5, Chapter 5.

PG&E will address any benefit savings achieved post-2009 in either the PG&E Test Year 2010 GRC or in another mechanism available at that time.

E. Potential for Interim Cost Recovery

If the CPUC has not determined its final decision in this application prior to PG&E's need for funding to continue AMI Project development, PG&E will ask the CPUC to create an interim funding review process so that the AMI project can continue on schedule. The CPUC has already indicated that it is important for PG&E to continue striving to meet aggressive AMI Project implementation goals, and a continual delay in funding would delay the progress of AMI Project deployment activities.

If this or a future Commission should change its view about the deployment of AMI, or if for some other reason PG&E is not allowed to continue with the AMI Project, then there is a possibility that parts of the AMI Project would be abandoned and would not meet the traditional "used and useful" standard for rate recovery. PG&E's shareholders should not be at risk for having all or part of their investment stranded because such an outcome would not be due to any imprudent action by PG&E. To provide reasonable certainty that PG&E will recover its costs of the AMI Project, the CPUC should adopt a policy that the utility should be allowed to recover all AMI-related costs so long as the expenditures were pursuant to and consistent with the specific AMI spending authority and guidance provided by this Commission.

F. Conclusion

PG&E requests cost recovery for the AMI Project costs through the creation of new gas and electric balancing accounts. Entries into these accounts would cover actual costs incurred net of forecast benefits as described in this chapter. A full review of forecast costs and benefits will take place as part of this application process, and once these forecasts have been reviewed and adopted, no further reasonableness review need occur, unless PG&E seeks cost recovery in excess of the amounts reviewed here. For 2006, PG&E will file an advice letter to include in rates the forecast AMI Project gas and electric revenue requirements once the Commission adopts this application. For the years 2007 to 2009, PG&E will recover the forecast AMI Project revenue requirements and the projected year-end balance recorded in the AMIBA in gas and electric rates in the Annual Gas True-up and Annual Electric True-up advice letters, or as otherwise authorized by the Commission.

PG&E seeks approval of this proposed cost recovery process.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

PLANT AND DEPRECIATION

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PLANT AND DEPRECIATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
PLANT AND DEPRECIATION

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E) expected plant and depreciation for PG&E's Advanced Metering Infrastructure (AMI) Project is reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

Plant and accumulated depreciation are primary components of the AMI Project rate base included in the calculation of the AMI Project revenue requirements. Depreciation expense is also included in the AMI revenue requirements. Estimated plant additions are developed from the capital expenditure forecasts presented in Exhibits 2 and 3. AMI Project plant includes the cost of assets, such as electric and gas meters, meter modules, metering communications network and associated information technology (IT) systems.

2. Summary of Dollar Request

PG&E requests that the Commission adopt PG&E's estimated expected plant additions as shown in Table 3-1.

TABLE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
EXPECTED PLANT ADDITIONS
($000s)

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5
1	Electric Plant	$83,297	$156,139	$171,664	$205,884	$127,072
2	Gas Plant	49,618	108,296	129,582	119,906	51,216
3	Total	$132,915	$264,435	$301,246	$325,790	$178,288

3. Support for Request

PG&E's expected AMI Project plant is reasonable and fully justifiable, because PG&E:

- Forecasted plant balances using the most currently available metering technology.
- Used the Request for Price (RFP) process to select the best available vendor in terms of technology and cost minimization;
- Accurately forecasted the plant additions consistent with the current technology and vendor selection; and
- Appropriately assigned depreciation rates to expected AMI Project plant balances consistent with past Commission decisions.

B. Plant Balance

As discussed in Exhibit 2, electric and gas meters or modules will be placed in service beginning in the first quarter of Year 1 with on-going installation expected to continue through the end of Year 5. Additionally, capital additions for IT infrastructure, hardware and associated operating system changes, and software will also be placed in plant-in-service as they become fully operative. At that time, they are considered used and useful and are functional in providing real-time interval data for both PG&E and PG&E's customers.

In preparation of this AMI Project Application, PG&E Program Managers estimated total expected capital additions for Year 1 to Year 5 consistent with PG&E's full deployment proposal. These capital additions were developed in terms of total financial costs. Total financial costs may include labor, material, material burden, external contracts, escalation, capitalized Administrative and General (A&G), Allowance for Funds Used During Construction (AFUDC) and other related costs that are incurred while purchasing or constructing AMI Project assets. Capitalized A&G represents a percentage of utility A&G expenses, including pensions and benefits, workers compensation, and administrative and staff costs that support capital project development.

AFUDC may be included in the cost of specific AMI Project capital work having a duration of greater than 30 days from the start of construction to the operative date, the date the AMI Project asset is transferred into service.

Capital expenditures for AMI Project capital work having a duration of less than 30 days is considered operative as installed and does not accrue AFUDC.

C. Depreciation

This section describes the depreciation expense and accumulated reserve for depreciation of AMI Project assets.

1. Depreciation Expense

Depreciation expense is an allocation of the cost of an asset whose usefulness has declined in service potential. Depreciation expense is developed using depreciation accrual rates based on the straight-line, remaining life method in accordance with CPUC Standard Practice U-4, <u>Determination of Straight-Line Remaining Life Depreciation Accruals</u>, dated January 3, 1961. The remaining life method allocates net plant balance (original plant less accumulated depreciation) over the estimated remaining life of the plant assets.

Group depreciation aggregates individual assets into groups. All assets in a group are depreciated using a single rate, which is based on the expected average life for all assets in the group. Implicit in the use of an average life to calculate depreciation expense is that some of the assets in the group are being depreciated with a life <u>shorter than the group average</u>, and some of the assets are being depreciated with a life <u>longer than the group average</u>. Accordingly, when assets are retired they are considered fully depreciated.

PG&E separately classifies AMI Project capital additions into unique asset classes, e.g., IT Equipment, IT Software, Electric and Gas Meters – AMI, or Electric and Gas Meter Communication Devices – AMI. For each asset class an estimate of depreciation expense is obtained by multiplying the weighted average plant for a given asset class by depreciation rates from PG&E's May 1, 2005 depreciation rate schedules filed with the CPUC.

PG&E proposes that new AMI Project meter modules without depreciation parameters authorized by the CPUC in PG&E's 2003 GRC Decision (D.04-05-055) accrue depreciation expense based on the meter module's economic (useful) life. The economic life is consistent with warranty parameters stipulated by third-party manufacturers or vendors.

The AMI Project book depreciation service lives and depreciation accrual rates are listed in Table 3-2 below.

TABLE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
DEPRECIATION LIFE AND RATES
($000s)

Line No.	Description	Average Life	Annual Rate (%)
1	Electric Meters	27	3.76
2	Electric Communication Devices	15	6.93
3	Gas Meters	24	4.90
4	Gas Communication Devices.	15	6.67
5	IT Equipment	15	6.67
6	IT Software	15	6.67
7	IT Programming and Project Management	15	6.67
8	Site Costs – Poles	15	6.67

2. Accumulated Depreciation

Accumulated depreciation is the sum of all depreciation expense accrued from the first day AMI Project assets are placed in plant-in-service (used and useful) until these assets are retired at the end of their economic life. The annual depreciation expense and accumulated deprecation for expected AMI Project assets are listed in Table 3-3 below.

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION
($000s)

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5
1	Depreciation Expense					
2	Electric	$4,708	$12,488	$23,024	$35,201	$46,014
3	Gas	2,869	8,118	16,015	24,299	29,982
4	Accumulated Depreciation					
5	Electric	4,708	17,197	40,220	75,421	121,435
6	Gas	2,869	10,987	27,002	51,301	81,283

3. Retirements of Plant

The ongoing retirement of meters, IT hardware and infrastructure is simply a reduction to plant for the original cost installed of these assets with an equal offsetting entry to accumulated depreciation. As a result, there is no impact to the net book value or undepreciated plant value (plant less accumulated deprecation reserve) for this entry, i.e., assets are considered fully depreciated when retired as a result of group depreciation.

D. Conclusion

PG&E requests that the Commission approve the expected capital additions, depreciation expense, and accumulated depreciation for the AMI Project.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

INCOME TAXES

PACIFIC GAS AND ELECTRIC COMPANY
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INCOME TAXES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
INCOME TAXES

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E) treatment for income taxes related to the acquisition and operation of Advanced Metering Infrastructure (AMI) assets, are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission). The tax expense amounts PG&E is requesting are necessary components of the cost of providing efficient and reliable gas and electric service to PG&E's customers.

2. Summary of Request

PG&E requests that the Commission adopt its estimate for income tax expense, which is a calculated amount dependent on: (1) the revenue and expenditure estimates provided by other witnesses in this case; and (2) the tax laws.

3. Support for Request

PG&E's forecast for income tax expense is reasonable and fully justifiable, because PG&E:

ffi Accurately reflects the tax laws in its calculation of tax expense;

ffi Uses Commission-mandated accounting and ratemaking methods; and

ffi Calculates Federal Income Tax (FIT) and California Corporate Franchise Tax (CCFT) taxable income using appropriate deductions and adjustments equivalent to, or forecasts from amounts filed in its federal and state tax returns.

B. Federal Tax Adjustments

FIT is computed in accordance with the requirements of the Internal Revenue Code (IRC). The following tax adjustments are applied to pre-tax book income to arrive at federal taxable income.

1. Capitalized Software

PG&E currently deducts the cost of self-developed software under Revenue Procedure 2000-50.[1] Pursuant to Decision 93848,[2] PG&E used flow-through tax accounting treatment for the amounts that are deductible under Revenue Procedure 2000-50.

PG&E capitalizes and depreciates acquired software on a straight-line basis over three years under section 167(f)[3] of the IRC. Pursuant to Decision 88-01-061,[4] PG&E used normalized tax accounting treatment for amounts that are capitalized under Section 167(f).

2. FIT Depreciation

The IRC specifies tax depreciation rules for FIT. These rules are based on the Modified Accelerated Cost Recovery System method (MACRS).[5] The depreciation lives for the AMI assets are listed in Chapter 5, Table 5-4.

Accelerated depreciation under the MACRS is permissible only if the FIT effects of life, method, and salvage timing differences between the book and tax methods of recovering MACRS tax basis are normalized. The MACRS depreciation on AMI Project assets will be normalized pursuant to Decision 93848 and Decision 88-01-061.

3. FIT Loss on Retirement of Existing Meters

Under the Accelerated Cost Recovery System (ACRS) and MACRS methods (applicable to property placed in service after 1980), PG&E may claim a loss on retirements of existing meters equal to the remaining tax basis in the retired property. As a result of recognizing a loss for tax purposes, but not for book purposes, a deferred tax liability is created that reduces rate base pursuant to Decision 93848 and Decision 88-01-061.

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[1] Rev. Proc. 2000-50, 2000-2 CB 601.

[2] D.93848, 7 CPUC 2d 332.

[3] The Omnibus Budget Reconciliation Act of 1993 (Pub. L. 103-66) added Section 167(f) to the IRC, effective for capitalized software purchased after August 10, 1993.

[4] D.88-01-061, 27 CPUC 2d 310.

[5] The MACRS determines tax depreciation of property placed in service after 1986, except for property subject to ACRS rules.

This deferred tax liability reverses as the un-depreciated book balance is recovered through book depreciation.

Under the ADR method of depreciation (applicable to property placed in service prior to 1981), a loss is not recognized on ordinary retirements. Instead, the remaining tax basis in the retired property is depreciated over its remaining tax depreciable life.

C. California Corporate Franchise Tax Adjustments

CCFT taxable income is computed in accordance with the statutory requirements of the California Revenue and Taxation Code (R&TC). The following tax adjustments are applied to pre-tax book income to arrive at California taxable income.

1. Capitalized Software

The CCFT treatment for software costs is the same as the FIT treatment described in Section B.1.

2. CCFT Depreciation

The R&TC specifies tax depreciation rules for CCFT. These rules are based on the Asset Depreciation Range method (ADR)[6] of depreciation. The depreciation lives for the AMI assets are listed in Chapter 5, Table 5-4. Decision 93848 provides for flow-through tax accounting for this adjustment, which PG&E follows in this proceeding.

3. CCFT Loss on Retirement of Existing Meters

Under ADR, a loss is not recognized on ordinary retirements.[7] Instead, the remaining tax basis in the retired property is depreciated over its remaining tax depreciable life.

[6] The ADR system of depreciation determines the CCFT depreciation of property placed in service after 1970.

[7] A loss would be recognized if the retirements were extraordinary; however, this is not expected to be the case for the retirement of existing meters. Under the ADR method of depreciation, all retirements other than extraordinary retirements are ordinary retirements. Certain retirement events will result in extraordinary retirements when the unadjusted basis of the assets retired from a vintage year account exceeds 20 percent of the unadjusted basis of such account immediately prior to the retirement event.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

COST OF SERVICE

(GAS AND ELECTRIC)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
COST OF SERVICE
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
COST OF SERVICE
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A. Introduction

The purpose of this chapter is to present forecasted, incremental annual revenue requirements needed to fund Pacific Gas and Electric Company's (PG&E) recommended Advanced Metering Infrastructure (AMI) deployment case for a 15-year period. These revenue requirements are incremental additional required revenues beyond those included in PG&E's 2003 General Rate Case (GRC) or anticipated to be requested (later this year) in PG&E's 2007 GRC.

The gas and electric revenue requirement calculations presented here compile all capital-related costs, operating expenses and savings into an income statement format to estimate the additional amount of revenue needed from customers to recover the cost of AMI Project deployment. This amount of revenue is known as the revenue requirement or cost of service; and, because of the income statement format, the model is known as the Results of Operations (RO).

PG&E is presenting these forecasted revenue requirements for several reasons:

- PG&E requests that initial rates for project deployment, to be effective July 1, 2006, be set based on the revenue requirements presented here, although ultimately PG&E proposes to recover actual costs of the project;
- PG&E also requests that AMI rates be changed January 1 of 2007, 2008, and 2009, based on the revenue requirements presented here for those years, plus balancing account balances calculated at the time the rates changes are requested with the electric and gas annual true-up filings;
- PG&E asks that the assumptions and methods used to calculate the capital revenue requirements shown here be approved for calculating monthly capital revenue requirements based on recorded AMI plant.

- The forecasted revenue requirements shown in this chapter were used to calculate and evaluate rate impacts of the AMI Project, shown in Chapters 6 and 7;

Although PG&E's cost recovery proposal seeks to recover the actual costs of the AMI project, PG&E requests that the California Public Utilities Commission (CPUC or Commission) approve the use of the revenue requirements set forth here, in combination with balancing account balances, to establish a streamlined method for setting and changing AMI rates from 2006 to 2009.

B. Summary of Revenue Requirement Results

PG&E estimated incremental AMI Project annual revenue requirements for the deployment phase of this project, beginning in the summer of 2006, and continuing for 15 years. For the initial rate change requested for July 1, 2006, PG&E has calculated a $77.5 million electric revenue requirement increase and a $35.5 million gas revenue requirement increase, as shown in Table 5-1 below.

TABLE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
INITIAL RATE REVENUE REQUIREMENTS ($000s)

Line No.		Electric	Gas
1	Year 1 Revenue Requirement	$40,803	$19,415
2	Year 0 Revenue Requirement	60,753	31,035
3	Less: Amount Requested in A.05-03-016	24,024	14,954
4	Estimated AMIMA Balance	$36,729	$16,081
5	Total Initial Request	$77,532	$35,496

In the above table, Year 1 is the first year of deployment, currently assumed to begin in 2006. The Year 1 revenue requirements include not only the first year revenue requirement for AMI deployment, but also the ongoing revenue requirements associated with pre-deployment capital expenditures. Year 0 represents the pre-deployment phase. While a portion of the revenue requirements for the pre-deployment period were requested in Application 05-03-016, additional pre-deployment dollars not identified in

Application 05-03-016, are being requested in this proceeding.[1] These additional dollars are shown in the table above as "Estimated AMIMA Balance."

As discussed in Chapter 2, "Cost Recovery," PG&E proposes ultimately to recover the recorded AMI Project revenue requirements, based on actual project costs net of benefits credited against those costs in the Advanced Metering Infrastructure Balancing Accounts (AMIBA) for electric and gas. To accomplish this, PG&E proposes that rates be set each year based on the forecasted revenue requirements presented here, plus balancing account balances to true up for actual costs and credited benefits during the previous year. A summary of the revenue requirements for the first five years of deployment is shown in Table 5-2, below.

TABLE 5-2
PACIFIC GAS AND ELECTRIC COMPANY
FORECASTED REVENUE REQUIREMENTS FOR AMI PROJECT ($000s)

Line No.	Description	Year 1	Year 2	Year 3	Year 4	Year 5
1	Electric RRQ	$40,803	$55,221	$65,525	$72,940	$54,265
2	Gas RRQ	19,415	29,105	39,737	52,878	53,405
3	Total RRQ	$60,218	$84,326	$105,262	$125,818	$107,670

These revenue requirements, along with the balances in the AMIBA for electric and gas, will be used to set the AMIBA rates under PG&E's proposal in Chapter 2. Forecasted revenue requirements for the remaining years are found in PG&E's workpapers.

C. Description of Incremental AMI Costs and Benefits

1. Summary

The net incremental AMI Project revenue requirements reflect the capital costs, operating expenses and benefits as computed in the net present value (NPV) model, described in Chapter 1, "Business Case Results

[1] PG&E filed its pre-deployment proposal on March 15, 2005 in Application 05-03-016. For this application, pre-deployment also includes the entire time period and expenditures before the "operational" date for the first meters. Application 05-03-016 only addresses the first six months of the pre-deployment period. Additional pre-deployment costs have been identified and are included in the pre-deployment period (Year 0) for this application.

and Present Value Model Methodology." The NPV analysis uses a cash-flow approach in analyzing the cost and benefits from the AMI Project. In this chapter, PG&E presents the costs and benefits in a regulatory (cost recovery) format. For this analysis, PG&E regroups the costs and benefits into capital-related and expense-related categories.

Demand response-related benefits (avoided procurement, transmission and distribution) discussed in Exhibit 4 are not included in PG&E's net revenue requirements, since these benefits are dependent on customer behavior and should not be viewed as a utility cost saving unless they materialize in the future. To the extent these savings occur, they will be reflected in customer rates at that time through future general rate cases, or other proceedings.

2. Capital Costs

This section describes the capital additions related to the AMI Project. Capital costs are grouped by the following classifications: (1) meters; (2) communication equipment; (3) information technology (IT) equipment; (4) IT software; (5) site costs (poles and building attachments); and (6) IT programming and project management.

PG&E has separated the costs between gas and electric, directly assigning capital assets to gas or electric rate base, as appropriate. Common plant additions, such as billing system hardware or the AMI server, have been allocated between gas and electric. For simplicity and consistency with the methods used in GRC proceedings, PG&E has allocated all common capital in proportion to the percentage of gas and electric meters deployed.

The NPV model includes some economic benefits that are typically recovered in other proceedings. For example, the revenue requirement analysis excludes timing differences associated with future capital additions or replacements such as, the avoided replacement of handheld equipment or load research surveys. These capital savings refer to delayed or non-expenditures, and until these investments need to be replaced in the future, there is no immediate customer savings. Therefore, costs and savings for these items will be captured in future general rate cases and other cases where the then planned capital expenditures will be captured.

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.[2] In the revenue requirements calculations, no adjustments were made for salvage and removal costs of these retired existing meters, thus assuming that salvage value equals removal costs. However, when the recorded costs are included in the AMIBA, recorded salvage values and recorded removal costs will be reflected.

For the new AMI assets, including meters and communication devices, because their expected lives exceeds the 15-year planning period, no specific adjustments were made for retirement or replacement of these assets. However, because some of the new assets are expected to fail during the planning period, replacements are included in the revenue requirement calculations based on the probability of failure for each type of equipment.

4. Operating Expenses and Benefits

This section describes the incremental operating expenses and savings related to the AMI Project. The majority of these expenses and savings support: (1) IT; (2) meters and communication equipment; (3) customer support; and (4) meter reading and billing. PG&E has categorized the cost components by functional group: (1) distribution; (2) customer accounts; (3) customer services; (4) IT hardware and software; and (5) administrative and general (A&G).

After categorizing the expenses, PG&E either directly assigned or allocated them to the electric or gas cost of service. As with the capital

[2] There may be a deferred tax benefit associated with some of the existing meters upon retirement. PG&E will capture these benefits in recorded data.

additions, the allocation for those expenses common to both electric and gas is computed by taking the cumulative number of AMI meters for each year and calculating the corresponding percentage of gas and electric meters. These percentages are multiplied by the total expenses and savings for a given year, creating a gas and electric breakdown for each individual category.

The NPV model has adjusted these estimates to include the appropriate overhead loaders, contingencies, and escalation. In addition, operating expenses and savings from the NPV model include provisions for non-burden benefits, and insurance and casualty costs. These costs and savings are shown as additional A&G costs in calculating the revenue requirements, and are estimated as a percentage of straight-time labor. The percentage used for non-burden benefits is 16.85 percent; the percentage for insurance and casualty costs is 6.58 percent. Both of these percentages are calculated using recorded 2004 data.

To estimate the incremental net AMI-related revenue requirement impacts, the expected expense savings or benefits derived from AMI implementation are deducted from the (gross) revenue requirement. These operating savings include: (1) revenue cycle services benefits, (2) reductions in meter reading costs, (3) reduced working cash requirements from synchronizing summary billing accounts to an earlier bill date; and (4) operational and administrative savings. In the revenue requirements calculations, these savings are reflected as negative operating expenses.

D. Elements of the Results of Operation Calculation

The AMI revenue requirements calculations show the revenues PG&E needs to cover the expense-related and capital-related costs expected to be incurred over the AMI Project planning horizon. In addition to the expenses described above, expense-related costs also include property, business and other taxes, which are based on the currently effective tax rates. PG&E applied franchise fees and uncollectible (FF&U) factors of 0.0117 (gas) and 0.0095 (electric) to the entire revenue requirement. These FF&U factors were adopted in PG&E's 2003 GRC Settlement Agreement (Decision 04-05-055). The various capital-related components of the RO calculation are discussed below. These revenue requirements calculations follow the plant depreciation and income tax assumptions described in Chapter 3, "Plant and Depreciation," and Chapter 4, "Income Taxes," respectively.

1. Depreciation

Depreciation is included in the cost of service calculations as both depreciation expense and accumulated depreciation.

Depreciation expense is calculated using depreciation accrual rates based on the straight-line, remaining life method in accordance with the CPUC Standard Practice U-4, *Determination of Straight Line Remaining Life Depreciation Accruals*. Depreciation measures the loss of value in tangible assets that occurs as the assets are used up over time. Depreciation expense represents the amount of that value recognized in a given year for recovery of prior capital investment. It is through depreciation expense, net of salvage value, that a utility recovers its original capital investment through rates.

PG&E classified the capital additions by plant type, thereby assigning the appropriate depreciation rate and service life. These classifications include: (1) meters; (2) communication equipment; (3) IT equipment; (4) IT software; (5) site costs; and (6) IT programming and project management. For each classification, PG&E estimates depreciation expense by multiplying the weighted average plant in service by the corresponding book depreciation rates from the May 1, 2005, depreciation accrual rate schedules filed with the CPUC. Table 5-3 summarizes the depreciable lives and depreciation rates that PG&E proposes for its AMI assets.

TABLE 5-3
PACIFIC GAS AND ELECTRIC COMPANY
BOOK DEPRECIATION ASSUMPTIONS

Line No.	Asset	Life	Rate
1	Electric Meters	27	3.76
2	Electric Communication Devices	15	6.93
3	Gas Meters	24	4.90
4	Gas Communication Devices	15	6.67
5	IT Equipment	15	6.67
6	IT Software	15	6.67
7	IT Programming & Project Management	15	6.67
8	Site Costs - Poles	15	6.67

Accumulated depreciation is calculated by adding estimated depreciation expense and net salvage value to the prior year's end-of-year reserve balance and subtracting the forecast asset retirements.

2. Rate Base

The elements of rate base included for AMI Project costs are: utility plant-in-service plus working capital, less deferred taxes, less accumulated depreciation. Utility plant-in-service consists of the accumulated original undepreciated investment in plant and equipment that is used and useful in rendering the services that are required by the AMI Project. In developing the associated rate base, certain deductions are made. A deduction is made for the accumulated deferred taxes associated with these assets. These deferred taxes result from following the Modified Accelerated Cost Recovery System (MACRS) tax depreciation method for federal income tax purposes. Due to the timing differences that result from the use of this tax depreciation method, taxes that have been paid for by the customer are not paid to the Internal Revenue Service (IRS) until a later date. Finally, plant is reduced by the amount of depreciation reserve, i.e., the accumulated depreciation already taken in prior years. Note, that for ease of calculation and presentation, working cash savings are reflected as negative operating expenses.

3. Rate of Return

PG&E multiplies the currently adopted composite rate of return of 8.77 percent by the AMI average rate base for each year to calculate the return on rate base. This calculation uses the rate of return and capital ratios adopted in PG&E's 2005 cost of capital decision (D.04-12-047).

4. Income Tax Depreciation Assumptions

This section describes the assumptions and calculations used in the revenue requirements calculations to estimate income tax depreciation. PG&E estimates California Corporation Franchise Taxes (CCFT) and federal income taxes on net operating income before income taxes. Federal income tax expense is the product of the currently effective corporate income tax rate (35 percent) and federal taxable income. Likewise, state income tax expense is the product of the statutory rate (8.84 percent) and the state taxable income.

Federal income taxes are computed on a normalized basis. This allows PG&E to recognize the timing differences between book and federal tax depreciation. This difference times the federal tax rate is called deferred federal income taxes, and is included as a credit to rate base.

State income taxes are calculated on a flow-through basis. Therefore, the ratepayers receive an immediate benefit from the use of accelerated state tax depreciation. There is no associated rate base deduction for deferred state taxes.

As described in Chapter 4, "Income Taxes," PG&E followed MACRS and Asset Depreciation Range (ADR)[3] guidelines for classifying AMI Project capital additions and calculating federal and state tax depreciation. While only software that exceeds a $5 million threshold is capitalized for book depreciation, all acquired software is capitalized for tax depreciation, and therefore, generates tax depreciation and deferred tax expense. Internally-developed software is expensed for tax purposes. Table 5-4 summarizes the federal and state tax depreciation methods used in the RO calculations.

[3] Uses sum of years digits (SYD) method.

TABLE 5-4
PACIFIC GAS AND ELECTRIC COMPANY
TAX ASSUMPTIONS

Line No.	Asset	Federal Tax Method	State Tax Method
1	Electric Meters	20 year MACRS	30 year ADR_SYD
2	Electric Communication Equipment	20 year MACRS	30 year ADR_SYD
3	Gas Meters	20 year MACRS	35 year ADR_SYD
4	Gas Communication Equipment	20 year MACRS	35 year ADR_SYD
5	IT Hardware	5 year MACRS	6 year ADR_SYD
6	IT Software (Acquired)	3 year Straight Line	3 year Straight Line
7	Site Costs –Poles	20 year MACRS	35 year ADR_SYD
8	Site Costs –Building Attachment	15 year Straight Line	15 year Straight Line

E. Conclusion

In calculating the revenue requirements presented in this chapter for the AMI Project, PG&E has used methods and factors consistent with those used in preparing its general rate cases. Only the size, scope, and timing of this project require it to be presented separately. Once the AMI project is deployed, it will be PG&E's metering standard and will be rolled into PG&E's general rate case requests. While PG&E recommends separate cost and revenue accounting for the AMI Project, the costs and savings will be recorded into the appropriate (Federal Energy Regulatory Commission) functional accounts. In a general rate case, these AMI Project costs would be presented for recovery in PG&E's distribution unbundled cost categories, since these types of costs are typically considered part of the distribution revenue requirements.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ELECTRIC COST ALLOCATION AND RATE PROPOSAL

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ELECTRIC COST ALLOCATION AND RATE PROPOSAL

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to specify the electric rate changes Pacific Gas and Electric Company (PG&E) requests initially to recover the costs of the Advanced Metering Infrastructure (AMI) project, and to provide illustrative electric rates based on the forecasted revenue requirements from Table 5-1 of this exhibit.

PG&E proposes to recover the cost of the AMI Project that is allocated to electric customers through electric distribution rates. This increase to distribution rates results in an increase to total rates for bundled customers, and an increase to total utility charges paid by direct access customers. PG&E's illustrative rates are based on forecast sales for 2006 and on revenue allocation and rate design methods used to change rates in 2004 and 2005. However, if the California Public Utilities Commission (CPUC or Commission) adopts a different standard for implementing distribution rate changes,[1] PG&E will adjust its proposed approach in this proceeding to be consistent.

2. Summary of Request

PG&E requests that the CPUC adopt PG&E's electric cost allocation and illustrative electric rates as reasonable.

B. Revenue Allocation

Unless revised in Phase 2 of its 2003 GRC, PG&E proposes relatively straightforward changes to electric rates to implement the AMI Project revenue requirement adopted in this proceeding. PG&E proposes to allocate the AMI Project revenue requirement in the same manner as other distribution revenue

[1] For example, in Phase 2 of its General Rate Case (GRC), PG&E has filed a settlement with the Commission regarding revenue allocation issues that would control how revenue requirement changes are implemented prior to a decision in Phase 2 of PG&E's 2007 GRC.

since the types of costs associated with the AMI Project are typically recovered in the distribution revenue requirement as described in Chapter 5. As noted above, PG&E intends to apply the revenue allocation method adopted by the Commission for distribution at the time of this rate change to reflect the AMI Project revenue requirement. PG&E has based its illustrative revenue allocation and rate design in this proceeding on the current revenue allocation methods for distribution. Specifically, PG&E proposes to allocate the AMI Project revenue requirement in proportion to each rate schedule's current share of distribution revenue. This approach is consistent with the current allocation practice set forth in the Rate Design Settlement Agreement (RDSA) approved by Decision 04-02-062. Paragraph 10 of the RDSA which provides:

> In the event that additional rate changes are needed prior to the adoption of the rates in phase 2 of PG&E's 2003 GRC due to changes in PG&E's total revenue requirement … such additional interim rate changes will be implemented based on the following principles: Changes in the revenue requirement of any given component will be recovered as an equal percent change in the component that is changing.

Specifically, PG&E first determines the distribution revenue at present rates for each rate schedule.[2] Then, PG&E increases each schedule's responsibility by the same percentage (e.g., the percent change in the distribution revenue requirement relative to distribution revenue at present rates). The proposed change to distribution revenue requirement amounts to an increase of $77.5 million, or 2.9 percent, relative to current June 1, 2005 rates in the first year, and an increase of $72.9 million, or 2.8 percent, relative to June 1, 2005 rates in the fourth year, which is also the year with the second highest AMI Project electric revenue requirement.

C. Rate Design

Once the revenue allocation for distribution is complete, rates for distribution are designed. Generally, total rates are then determined by summing the applicable rate components. However, in the residential class, total charges for Tier 1 and Tier 2 usage (i.e., usage up to 130 percent of baseline) are constrained at levels as adopted by the Commission as of February 1, 2001.

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[2] Revenue at present rates was determined using rates effective June 1, 2005, and forecast sales for 2006.

1. Distribution Rate Design

Consistent with past practice, PG&E proposes no adjustment to distribution customer and meter charges. Accordingly, distribution demand and energy charges are increased by the percent change required to collect the change in distribution revenue allocated to each rate schedule.

2. Total Rate Design

After determining the rate components for each rate schedule, total rates are determined by simply summing the rates that are not changing in this proceeding (such as the nuclear decommissioning) and the proposed rates for distribution.

In general, this step is straightforward. However, in the residential class, total charges for Tier 1 and Tier 2 usage cannot be increased.[3] Therefore, to implement an increase for the residential class, PG&E proposes to offset the increase in distribution rates with an equal and opposite change to Tier 1 and Tier 2 generation rates to ensure that total Tier 1 and Tier 2 rates are not increased. Then, to ensure that the proper total revenue is collected, Tier 3 and Tier 4 rates are increased proportionally to collect the remaining revenue allocated to the class.[4]

In the event that the AMI Project revenue requirement is implemented at the same time as other revenue requirement changes such that the residential class receives an overall reduction, PG&E proposes that Tier 1 and Tier 2 rates for usage less than 130 percent of baseline be maintained at their current level. PG&E proposes to proportionally reduce Tier 3 and Tier 4 rates to reflect the full reduction allocated to the class.

3. The Automated Meter Infrastructure Balancing Account Rate

As discussed in Chapter 2, the electric Automated Meter Infrastructure Balancing Account (AMIBA) will require an entry for electric AMI revenue. AMI revenue will be collected from customers as part of the electric

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[3] Water Code Section 80110 prohibits increases to total charges for residential usage up to 130 percent of baseline until such time as the California Department of Water Resources (DWR) has recovered the costs of power it has procured for the electrical corporation's retail end-use customers.

[4] The method described above adjusts residential rates such that the incremental surcharges for Tier 3 and Tier 4 are the same for all residential rate schedules.

distribution charge and then separated into subcomponents, including AMI revenue. AMI revenue will be determined by multiplying a rate per kilowatt-hour (kWh) by all applicable sales (usage subject to distribution rates). The AMIBA rate is included in Preliminary Statement Part I, Rate Summary, and is derived by dividing the AMI Project revenue requirement by test year sales. The electric AMIBA rate for Year 1, based on the forecast of 2006 sales, is $0.00092 per kWh.[5]

D. Illustrative Revenue Allocation and Rate Design

Illustrative average revenue allocation results for Year 1, based on forecast sales for 2006, are shown for bundled service customers and for direct access customers in Appendix D. Illustrative rates for each rate schedule for Year 1 are shown in the Appendix E. Finally, Appendix F includes class-level illustrative average revenue allocation results and sample residential bundled customer bill changes, projected through Year 5 based on the net revenue requirements shown in Table 5-1 and Table 5-2.

[5] The AMIBA rate = $77.5 million/83,864 gigawatt-hours (GWh).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

GAS COST ALLOCATION AND RATE PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
GAS COST ALLOCATION AND RATE PROPOSAL

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
GAS COST ALLOCATION AND RATE PROPOSAL

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) cost allocation and rate proposal for the Advanced Metering Infrastructure Project (AMI Project) gas revenue requirement as set forth in Chapter 5. PG&E requests that the revenue requirements shown on Chapter 5, Table 5-2, for Years 1 through 5, be adopted for setting rates for recovery of AMI Project costs. Upon approval of this application, initial rates will be set to recover the Year 1 forecast project revenue requirements, plus the balance in the gas Advance Metering Infrastructure Balancing Account (AMIBA), as shown on Table 5-1. As discussed in Chapter 2, the gas AMIBA will be trued-up each month to record actual costs, actual revenues and benefits. At the end of each year, the forecasted amount for the subsequent year, plus the balance in the Gas AMIBA will be reflected in core distribution rates in conjunction with the Annual True-up of Balancing Accounts (Annual True-up). PG&E files its annual true-up no later than 40 days prior to each January 1st rate change.

2. Summary of Request

PG&E requests that the California Public Utilities Commission (CPUC or Commission) adopt PG&E's gas cost allocation proposal and illustrative gas rates as reasonable.

B. Gas Cost Allocation and Rate Proposal

PG&E proposes to allocate the authorized gas AMI Project revenue requirement to core customer classes based upon each class's respective share of distribution marginal cost revenues. An allocation of the AMI Project revenue requirement using distribution marginal cost revenues is consistent with PG&E's current methodology for allocating customer and distribution related costs. Gas AMI Project costs allocated to each core customer class will be reflected in the distribution component of core rates. This will allow for consistency with the eventual treatment of gas distribution AMI Project costs in the general rate case (GRC), in the future.[1] As discussed in Chapter 5, the AMI Project is being implemented for core gas customers only, and not for noncore gas customers.[2] Thus, there is no direct allocation of AMI Project costs to noncore gas customers.

Residential gas customers who qualify for PG&E's California Alternate Rates for Energy (CARE) program, receive a 20 percent discount on their transportation and procurement rates.[3] The cost of providing the CARE discount is allocated to all non-CARE core and noncore industrial customers on an equal cents per therm basis. This practice results in an allocation of incremental gas AMI Project costs to noncore industrial customers.

The following Table 7-1 shows the allocation of the Year 1 AMI Project gas revenue requirement among customer classes and the illustrative class average rate impacts under PG&E's proposal, compared to illustrative present rates. The Years 2 through 5 AMI Project revenue allocation to gas customer classes and illustrative class average rate impacts are presented in Appendix G.

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[1] GRC authorized gas distribution costs are allocated to gas customer classes in Biennial Cost Allocation Proceedings (BCAP), based on customer and distribution marginal cost studies.

[2] PG&E has installed or is in the process of installing AMI or AMR meters for all noncore gas customers. Noncore customer AMI/AMR meter purchase and installation was addressed in the Gas Accord II – 2004 Decision (D.) 03-12-061.

[3] CARE eligibility and certification criteria are set forth in PG&E Gas Rules 19.1, 19.2, or 19.3.

TABLE 7-1
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
ALLOCATION OF YEAR ONE GAS AMI PROJECT REVENUE REQUIREMENT TO CUSTOMER CLASSES AND ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES
($THOUSANDS, $/THERM)

Line No.	Customer Class	Year 1 Gas AMI Project Revenues (000's)	Present Rates ($/therm)	Year 1 Proposed Rates ($/therm)	% Change
1	Bundled – Retail Core(a)				
2	Residential	$26,278	$1.117	$1.129	1.1%
3	Small Commercial	6,487	1.082	1.092	0.9%
4	Large Commercial	105	0.899	0.904	0.5%
5	Transportation Only – Retail Core(b)				
6	Residential	367	0.386	0.398	3.1%
7	Small Commercial	1,610	0.359	0.369	2.9%
8	Large Commercial	25	0.201	0.206	2.2%
9	Transportation Only – Retail Noncore(b)				
10	Industrial – Distribution	53	0.120	0.120	0.1%
11	Industrial – Transmission	259	0.042	0.043	0.4%
12	Industrial – Backbone	0	0.024	0.024	0.0%
13	Electric Gen. – Dist/Transmission	0	0.016	0.016	0.0%
14	Electric Gen. – Backbone	0	0.001	0.001	0.0%
15	Transportation Only – Wholesale(b)	0	0.017	0.017	0.0%
16	Total	$35,184			

(a) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG); (ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy, low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(b) Transportation Only rates include: (i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy, low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transport only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(c) Percentage change differences are due to rounding of rates to three digits for illustrative presentation.

Illustrative present rates are based on the core illustrative procurement rates filed in Advice 2600-G, the core transportation and gas public purpose program (PPP) surcharges filed in Advice 2612-G, and the noncore transportation and gas PPP surcharges filed in Advice 2613-G, effective March 1, 2005. Present and proposed bundled core rates presented in this chapter include an illustrative average WACOG of $0.615 per therm, filed in Advice 2600-G.

If the Commission approves PG&E's AMI Project request, a residential gas customer using 45 therms per month in Year 1, would see an average monthly gas bill increase of $0.54, or 1.1 percent, from $50.28 to $50.82. Individual bills may differ, however.

C. Conclusion

PG&E requests that the Commission approve PG&E's cost allocation and rate proposal for annual authorized AMI Project gas revenue requirements.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

BUSINESS CASE RESULTS TABLES

TABLE A-1
PACIFIC GAS AND ELECTRIC COMPANY
AMI PROJECT FIVE YEAR COST BY MONTH[a]

	Jan	Feb	Mar	Apr	May	Jun	Sub Total	July	Aug	Sep	Oct	Nov	Dec	Sub Total	Annual Total
2005 / YEAR 0								*Year 0*							
Capital								0.0	1.0	12.3	0.0	0.0	0.0	13.3	
Expense								2.6	2.5	4.0	15.9	5.2	5.6	35.8	
														49.1	$49
2006 / YEAR 0/1	*Year 0*							*Year 1*							
Capital	4.2	4.3	4.7	5.4	5.9	6.4	30.9	47.6	6.6	7.9	11.4	12.9	14.0	100.4	
Expense	7.9	7.9	8.0	8.9	9.3	9.6	51.6	4.7	4.8	4.9	4.9	4.8	5.0	29.1	
							82.5							129.5	$212
2007 / YEAR 2	*Year 2*							*Year 2*							
Capital	13.9	16.8	17.8	18.6	19.7	20.6	107.4	21.4	22.5	23.0	22.5	21.6	23.7	134.7	
Expense	3.9	3.9	3.9	3.9	4.1	4.1	23.8	4.1	4.1	4.3	4.3	4.4	4.5	25.7	
							131.2							160.4	$292
2008 /YEAR 3	*Year 3*							*Year 3*							
Capital	23.3	22.5	22.5	21.8	22.5	23.5	136.1	23.4	22.6	22.5	24.3	23.5	24.6	140.9	
Expense	4.5	4.6	4.7	5.0	5.1	5.2	29.1	5.4	5.6	5.7	5.9	6.0	6.3	34.9	
							165.2							175.8	$341
2009 / YEAR 4	*Year 4*							*Year 4*							
Capital	23.1	23.9	25.8	24.8	26.2	23.5	147.3	35.6	22.9	23.9	23.8	22.5	20.0	148.7	
Expense	6.3	6.2	6.2	6.2	6.2	6.1	37.2	6.0	5.9	6.0	5.9	5.8	5.7	35.3	
							184.5							184.0	$369
2010 / YEAR 5	*Year 5*							*Year 5*							
Capital	18.1	18.2	18.2	18.1	17.1	13.5	103.2	11.7	9.6	9.6	9.5	9.6	7.6	57.6	
Expense	5.6	5.7	5.6	5.6	5.5	5.5	33.5	5.4	5.4	5.3	5.3	5.2	5.2	31.8	
							136.7							89.4	$226
Capital	82.6	85.7	89.0	88.7	91.4	87.5	524.9	139.7	85.2	99.2	91.5	90.1	89.9	595.6	
Expense	28.2	28.3	28.4	29.6	30.2	30.5	175.2	28.2	28.3	30.2	42.2	31.4	32.3	192.6	
Total	110.8	114.0	117.4	118.3	121.6	118.0	700.1	167.9	113.5	129.4	133.7	121.5	122.2	788.2	$1,488

(a) Five-year cost by month does not include risk-based allowance costs.

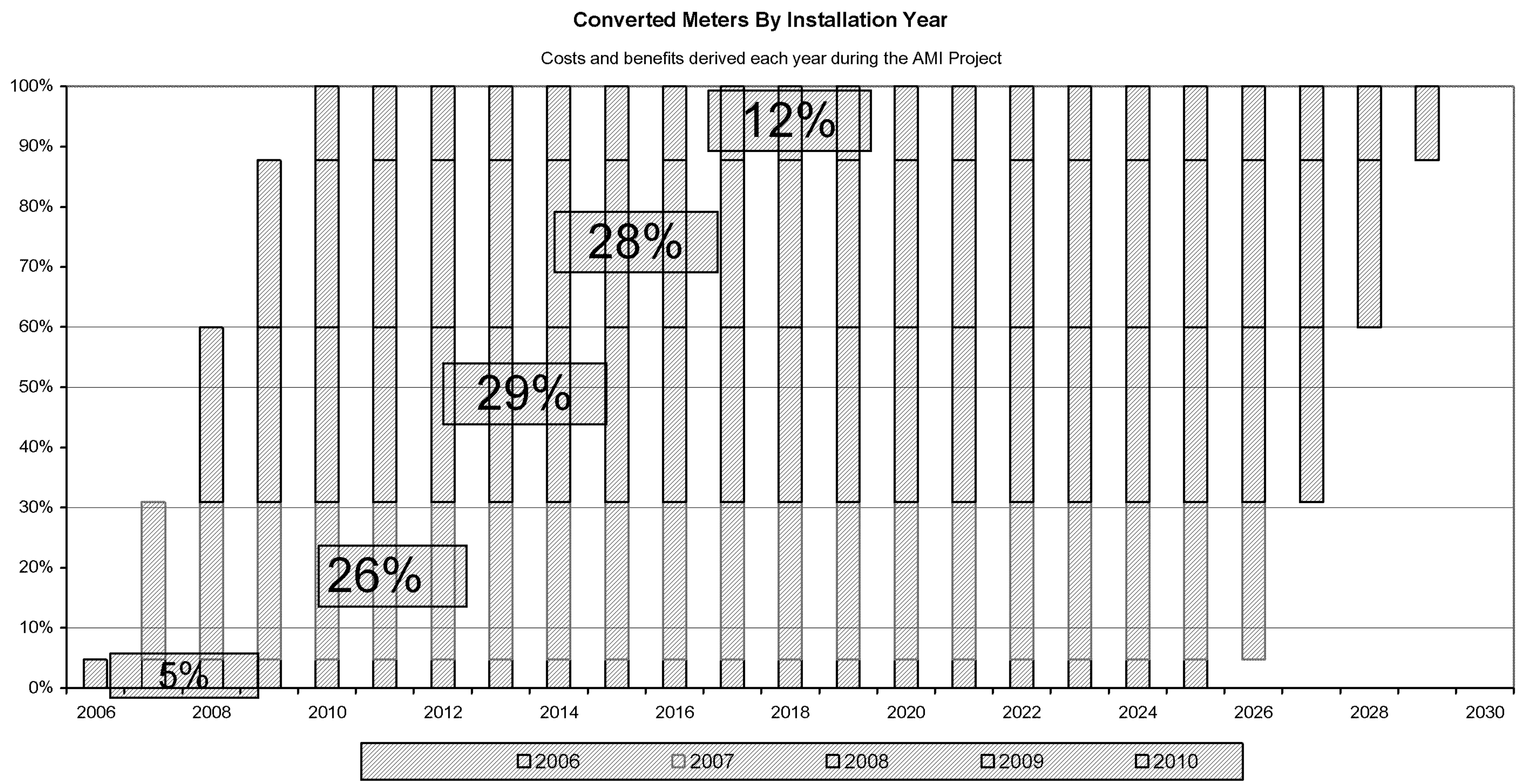
TABLE A-2
PACIFIC GAS AND ELECTRIC COMPANY
DEPLOYMENT & OPERATING COSTS DETAIL

Line No.	Cost Category	Estimated Costs 2006 – 2010 ($ in millions))	Source Chapter	Year 0 2005 ($M)	Year 0/1 2006 ($M)	Year 2 2007 ($M)	Year 3 2008 ($M)	Year 4 2009 ($M)	Year 5 2010 ($M)	PVRR ($ millions)
1	Project management costs	$85.6	Ex 1, Ch2	$ 8.8	$20.4	$14.1	$14.1	$14.1	$14.1	$87.2
2	Risk-based allowance	128.8	Ex 1, Ch 2	-	44.4	19.0	22.1	28.2	15.0	135.0
3	Meters and modules	628.3	Ex 2, Ch 1	1.5	46.3	154.8	172.9	168.7	84.3	862.1
4	Network materials	64.4	Ex 2, Ch 1	13.6	2.7	12.9	13.9	14.3	6.9	77.0
5	AMI operations	30.0	Ex 2, Ch 1	-	4.6	5.0	5.8	6.9	7.7	82.2
6	Interface and systems integration	115.9	Ex 2, Ch 2	21.2	45.9	9.5	9.7	19.5	10.1	196.3
7	Interval billing system	83.5	Ex 2, Ch 3	4.0	61.7	3.6	3.4	7.5	3.4	107.1
8	Meters / modules installation	254.4	Ex 2, Ch 4	-	7.0	51.6	66.6	75.2	54.0	287.4
9	Electric network and WAN installation	47.2	Ex 2, Ch 4	-	2.5	12.1	12.4	13.5	6.6	54.6
10	Gas network and other installation	11.3	Ex 2, Ch 4	-	0.5	3.0	3.6	3.0	1.2	13.9
12	Meters / modules QA sample testing	2.8	Ex 2, Ch 4	-	0.5	0.5	0.6	0.6	0.6	2.3
13	Meter operations costs	38.2	Ex 3, Ch 3	-	0.8	3.5	7.6	11.8	14.5	172.4
14	Customer contact-related costs	26.2	Ex 3, Ch 4	-	4.6	5.8	5.5	6.2	4.1	33.0
15	Customer exceptions processing	4.9	Ex 3, Ch 5	-	1.0	1.0	1.0	1.0	1.0	4.1
16	Marketing and communications	20.4	Ex 4, Ch 2	-	4.1	3.3	4.3	4.3	4.4	22.5
17	Customer acquisition	53.3	Ex 4, Ch 3	-	1.7	7.9	16.3	18.0	9.4	44.0
18	Other employee related costs	21.9	Ex 5, Ch 1	-	7.8	2.9	3.4	3.9	3.9	45.7
19	Total Estimated Project Costs (totals subject to rounding error)	$1,617.0		$49.1	$256.4	$310.6	$363.1	$396.7	$241.1	**$2,226.7**

TABLE A-3
PACIFIC GAS AND ELECTRIC COMPANY
OPERATING BENEFITS DETAIL

Line No.	Benefit Category	Annualized Benefit after Implementation (2005 $ million)	Source Chapter	Year 1 2006 ($M)	Year 2 2007 ($M)	Year 3 2008 ($M)	Year 4 2009 ($M)	Year 5 2010 ($M)	Year 10 2015 ($M)	PVRR ($ millions)
1	Operational Meter Reading	($86.2)	Ex 3, Ch1	($0.4)	($10.2)	($35.4)	($58.0)	($85.5)	($126.6)	($1,085.2)
2	Electric Transmission & Distribution	(12.8)	Ex 3, Ch 2	(0.1)	(1.7)	(5.4)	(9.7)	(14.7)	(19.9)	(179.1)
3	Meter Operations	(7.0)	Ex 3, Ch 3	(0.0)	(1.0)	(3.3)	(5.8)	(8.4)	(11.6)	(104.2)
4	Customer Contact	(2.7)	Ex 3, Ch 4	(0.0)	(0.4)	(1.3)	(2.3)	(3.3)	(4.5)	(40.3)
5	Billing Benefits	(18.6)	Ex 3, Ch 5	-	(1.5)	(7.6)	(13.6)	(19.5)	(24.9)	(218.3)
6	Gas Transmission & Distribution	(1.2)	Ex 3, Ch 7	-	-	-	(0.9)	(1.0)	(0.5)	(10.2)
7	Remote Electric Turn-on / Shut-off	(11.5)	Ex 2, Ch 4	(0.0)	(0.9)	(3.2)	(7.4)	(12.1)	(11.4)	(103.1)
8	Reduced Software Licensing Expense	(5.0)	Ex 2, Ch 3	-	(2.6)	(5.0)	(5.0)	(5.0)	(5.0)	(47.8)
9	Other Employee-Related Costs	(18.9)	Ex 5, Ch 1	(0.1)	(2.1)	(7.3)	(12.8)	(18.9)	(25.1)	(220.7)
10	**Total Annual Benefit**	($163.8)		($0.6)	($20.4)	($68.4)	($115.3)	($168.4)	($229.5)	($2,008.8)
12	Reduced Equipment Replacement	(8.5)	Ex 3, Ch 1	-	-	-	-	-	-	(10.2)
13	Deferred Meter Testing	(1.6)	Ex 3, Ch 3	(0.1)	(0.5)	(1.1)	(1.6)	(1.9)	-	(7.0)
14	**Total One Time Benefits**	($10.1)		($0.1)	($0.5)	($1.1)	($1.6)	($1.9)	-	($17.2)
15										
16	**Total Benefits** (totals subject to rounding error)									**($2,026.0)**

FIGURE A-1
PACIFIC GAS AND ELECTRIC COMPANY
AMI DEPLOYMENT BY INSTALLATION YEAR



PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

PROPOSED PRELIMINARY STATEMENTS

PRELIMINARY STATEMENT

XX. Advanced Metering Infrastructure Balancing Account-Gas (AMIBA-G) (N)

1. PURPOSE: The purpose of the Advanced Metering Infrastructure Balancing Account-Gas (AMIBA-G) is to record and recover the incremental Operations and Maintenance (O&M) and Administrative and General (A&G) expenditures, capital-related costs, capital-related revenue requirements, benefits, and revenues associated with the Advanced Metering Infrastructure (AMI) Project as authorized by the Commission in Decision (D.XX-XX-XXX). Upon Commission approval of the cost recovery mechanism in the AMI Project Application (A.XX-XX-XXX), PG&E will transfer the balance from the AMIMA-G to this account (AMIBA-G) for rate recovery. Any under- or over-collection in this account will be incorporated into core transportation rates as part of the next Annual Gas True-up Advice Letter.

2. APPLICABILITY: The AMIBA-G applies to all core gas transportation rate schedules and contracts subject to the jurisdiction of the CPUC, except for those schedules and contracts specifically excluded by the CPUC.

3. REVISION DATE: Disposition of the balance in this account shall be determined in the Annual Gas True-up Advice Letter, or as otherwise authorized by the Commission.

4. RATES: The AMIBA-G rate component is included in the effective rates set forth in the Gas Preliminary Statement, Part B, as applicable.

5. ACCOUNTING PROCEDURE: PG&E shall maintain the AMIBA-G by making entries to this account at the end of each month as follows:

   a. A credit entry equal to the revenues from the AMI rate component, excluding the allowance for Franchise Fees and Uncollectible (FF&U) Accounts expense.

   b. A credit entry for the calculated benefits achieved through the AMI Project, as set forth in the AMI Project Application (A.XX-XX-XXX) and approved in Decision XX-XX-XXX.

   c. A debit entry equal to PG&E's incremental O&M and A&G expenses and capital-related costs incurred for the AMI Project. Capital-related revenue requirements include depreciation expense, the return on investment, federal and state income taxes, and property taxes associated with the costs of installed equipment. These capital-related revenue requirements and O&M and A&G costs may relate to numerous activities or organizations, including but not limited to the following areas:

      ffi AMI project management, including contract management and development, communications, budget and accounting management, human resource management, process redesign, and other related areas
      ffi Communication systems, including network controllers and telecommunications links
      ffi Customer outreach and customer care
      ffi Data collector hardware and software
      ffi Development of training materials and procedures
      ffi Evaluation and planning
      ffi Facilities
      ffi Gas and electric meters, transmitting modules, and related equipment
      ffi Logistics management tools and activities
      ffi Meter installation, including customer data exceptions processing
      ffi Network operations staff
      ffi Operations center hardware and systems
      ffi Site surveys and development
      ffi System design, programming, and other upgrades/enhancements for integrated systems including billing, records, customer information and other information systems using meter information (N)

(Continued)

PRELIMINARY STATEMENT
(Continued)

XX. Advanced Metering Infrastructure Memorandum Account-Gas (AMIMA-G) (N)

5. ACCOUNTING PROCEDURE: (Cont'd.)

c. (Cont'd.)

ffi Technical support staff and operations
ffi Testing of systems and processes
ffi Training

d. An entry to record the transfer of the balance from AMIMA-G to this account for recovery in rates, upon approval by the CPUC.

e. An entry equal to the interest on the average of the balance in the account at the beginning of the month and the balance in the account after the above entries, at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (N)

PRELIMINARY STATEMENT

XX. Advanced Metering Infrastructure Balancing Account-Electric (AMIBA-E) (N)

1. PURPOSE: The purpose of the Advanced Metering Infrastructure Balancing Account-Electric (AMIBA-E) is to record and recover the incremental Operations and Maintenance (O&M) and Administrative and General (A&G) expenditures, capital-related costs, capital-related revenue requirements, benefits, and revenues associated with the Advanced Metering Infrastructure (AMI) Project as authorized by the Commission in Decision (D.XX-XX-XXX). Upon Commission approval of the cost recovery mechanism in the AMI Project Application (A.XX-XX-XXX), PG&E will transfer the balance from the AMIMA-E to this account (AMIBA-E) for rate recovery. Any under- or over-collection in this account will be incorporated into distribution rates as part of the next Annual Electric True-up Advice Letter.

2. APPLICABILITY: The AMIBA-E applies to all customer classes, except for those specifically excluded by the Commission.

3. REVISION DATE: Disposition of the balance in this account shall be determined in the Annual Electric True-up Advice Letter, or as otherwise authorized by the Commission.

4. RATES: The AMIBA-E rate component is included in the effective rates set forth in the Electric Preliminary Statement, Part I, as applicable.

5. ACCOUNTING PROCEDURE: PG&E shall maintain the AMIBA-E by making entries to this account at the end of each month as follows:

   a. A credit entry equal to the revenues from the AMI rate component, excluding the allowance for Franchise Fees and Uncollectible (FF&U) Accounts expense.

   b. A credit entry for the calculated benefits achieved through the AMI Project, as set forth in the AMI Project Application (A.XX-XX-XXX) and approved in Decision XX-XX-XXX.

   c. A debit entry equal to PG&E's incremental O&M and A&G expenses and capital-related costs incurred for the AMI Project. Capital-related revenue requirements include depreciation expense, the return on investment, federal and state income taxes, and property taxes associated with the costs of installed equipment. These capital-related revenue requirements and O&M and A&G costs may relate to numerous activities or organizations, including but not limited to the following areas:

      ffi AMI project management, including contract management and development, communications, budget and accounting management, human resource management, process redesign, and other related areas
      ffi Communication systems, including network controllers and telecommunications links
      ffi Customer outreach and customer care
      ffi Data collector hardware and software
      ffi Development of training materials and procedures
      ffi Evaluation and planning
      ffi Facilities
      ffi Gas and electric meters, transmitting modules, and related equipment
      ffi Logistics management tools and activities
      ffi Meter installation, including customer data exceptions processing
      ffi Network operations staff
      ffi Operations center hardware and systems
      ffi Site surveys and development
      ffi System design, programming, and other upgrades/enhancements for integrated systems including billing, records, customer information and other information systems using meter information (N)

(Continued)

PRELIMINARY STATEMENT
(Continued)

XX. Advanced Metering Infrastructure Memorandum Account-Gas (AMIBA-E) (N)

5. ACCOUNTING PROCEDURE: (Cont'd.)

c. (Cont'd.)

ffi Technical support staff and operations
ffi Testing of systems and processes
ffi Training

d. An entry to record the transfer of the balance from AMIMA-E to this account for recovery in rates, upon approval by the CPUC.

e. An entry equal to the interest on the average of the balance in the account at the beginning of the month and the balance in the account after the above entries, at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor. (N)

APPENDIX C

ILLUSTRATIVE BENEFITS CALCULATION

Pacific Gas & Electric Company
Advanced Metering Infrastructure (AMI) Project
Illustrative Benefits Calculation

**Numerical data, unless otherwise noted, are from the Summary of AMI Benefits (Workpapers Supporting Exhibit 5, Chapter 1)*

Benefits Proportional to Meter Activation (Line 36)	Benefit Savings	
Year 1	$630,075	
Year 2	$17,849,332	
Year 3	$60,708,847	
Year 4	$104,342,546	
Total Meter Activation Benefits -	$183,530,800	
Average Active Meters (Line 41)	Meters	
Year 1	38,739	
Year 2	1,150,612	
Year 3	3,881,156	
Year 4	6,847,570	
Total Active Meter Years -	11,918,077	
(1) Average Benefits Per Active Meter Year (Years 1-4)	$15.39936	
(2) Average Benefits Per Active Meter Month (Years 1-4)	**$1.283280**	
Benefits Proportional to Interval Meter Installation (Line 10)[1]	Meters	
Year 1	$0	Interval meters not yet being converted
Year 2	$0	Interval meters not yet being converted
Year 3	$2,737.72	
Year 4	$4,298.20	
Total Interval Meter Benefits -	$7,035.92	
Average Converted Interval Meters[2]	Meters	
Year 1	0	
Year 2	0	
Year 3	2,629	39% (Line 43) x total 6,740 interval meters
Year 4	4,516	67%(Line 43) x total 6,740 interval meters
Total Interval Meter Years -	7,145	
(3) Average Benefits Per Interval Meter Year (Years 3-4)	$0.9847	
(4) Average Benefits Per Interval Meter Month (Years 3-4)	**$0.0821**	
Benefits Proportional to Reduced Software Licensing (Line 15/Ex.2, Chapt. 3)[3]	Benefit Savings	
Beginning the January following completion of Phase 3 (Non-Computer Associates Mainframe Software Licensing)	$1,400,000	
Beginning the October following completion of Phase 3 (Computer Associates Mainframe Software Licensing)	$3,600,000	
Total Reduced Software Licensing Benefits Per Year	$5,000,000	Beginning in October following Phase 3
Beginning the January following completion of Phase 3:		
(5) Non-Computer Associates Benefits Per Month	$116,667	
Reduced Software Licensing Benefits Per Month (Beginning January)	**$116,667**	
Beginning the October following completion of Phase 3:		
Non-Computer Associates Benefits Per Month	$116,667	
(6) Computer Associates Benefits Per Month	$300,000	
(7) Reduced Software Licensing Benefits Per Month (Beginning October)	**$416,667**	

Formula Calculations:

(1) Total Meter Activation Benefits ÷ Total Active Meter Years = Average Benefits Per Active Meter Year
(2) Average Benefits Per Active Meter Year ÷ 12 Months = Average Benefits Per Active Meter Month
(3) Total Interval Meter Benefits ÷ Total Interval Meter Years = Average Benefits Per Interval Meter Year
(4) Average Benefits Per Interval Meter Year ÷ 12 Months = Average Benefits Per Interval Meter Month
(5) Benefits Proportional to Reduced Software Licensing Per Year(Beginning the January following completion of Phase 3) ÷ 12 Months = Non-Computer Associates Benefits Per Month (Beginning January)
(6) Benefits Proportional to Reduced Software Licensing Per Year (Beginning the October following completion of Phase 3) ÷ 12 Months = Computer Associates Benefits Per Month (Beginning October)
(7) Non-Computer Associates Benefits Per Month *(Beginning the January following completion of Phase 3) + Computer Associates Benefits Per Month (Beginning the October following completion of Phase 3) = Reduced Software Licensing Benefits Per Month (Beginning October)*

Monthly Calculations:

A. Average Benefits Per Active Meter Month x Number of Cumulative Meters Activated
B. Average Benefits Per Interval Meter Month x Number of Cumulative Interval Meters Installed
C. Benefits Per Reduced Software Licensing Month (if any)

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[1] Interval meters are not converted until after stabilization of the CC&B system upgrade.
[2] Once interval meters begin conversion, they are converted in the same proportion as meter activation. The estimated total number of AMI interval meters to be installed is 6,740, as discussed in Exhibit 3, Chapter 5.
[3] Benefits are for reduced software licensing expense related to the upgrade of PG&E's Customer Care and Billing (CC&B) system. Non-Computer Associates benefits will begin the January following the completion of Phase 3 of the CC&B system. Computer Associates benefits begin in October following the completion of Phase 3, and benefits per month will increase accordingly. Benefits will be allocated to electric and gas by the number of activated meters per month, as shown in the Benefit Estimates table of the Workpapers Supporting Exhibit 5, Chapter 5. Completion of Phase 3 is expected to occur in November 2006, as discussed in Exhibit 2, Chapter 3.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX F

CLASS-LEVEL ILLUSTRATIVE ELECTRIC REVENUE ALLOCATION RESULTS

YEAR 1 THROUGH YEAR 5

Electric Department
Appendix F
Class-Level Illustrative Electric Revenue Allocation Results
Year 1 through Year 5

Electric Customer Class	Present Rate ($/kWh)	Year 1 Illustrative Rate ($/kWh)	Year 1 Change from Present Rate (%)	Year 2 Illustrative Rate ($/kWh)	Year 2 Change from Present Rate (%)	Year 3 Illustrative Rate ($/kWh)	Year 3 Change from Present Rate (%)	Year 4 Illustrative Rate ($/kWh)	Year 4 Change from Present Rate (%)	Year 5 Illustrative Rate ($/kWh)	Year 5 Change from Present Rate (%)
Bundled Service											
Residential	$0.12893	$0.13018	1.0%	$0.12982	0.7%	$0.12998	0.8%	$0.13010	0.9%	$0.12980	0.7%
Small Light and Power	$0.14597	$0.14730	0.9%	$0.14692	0.6%	$0.14710	0.8%	$0.14723	0.9%	$0.14690	0.6%
Medium Light and Power	$0.13654	$0.13728	0.5%	$0.13707	0.4%	$0.13717	0.5%	$0.13724	0.5%	$0.13706	0.4%
E-19 Class	$0.12342	$0.12411	0.6%	$0.12391	0.4%	$0.12401	0.5%	$0.12407	0.5%	$0.12391	0.4%
Streetlights	$0.14770	$0.15004	1.6%	$0.14937	1.1%	$0.14968	1.3%	$0.14990	1.5%	$0.14934	1.1%
Standby	$0.13213	$0.13261	0.4%	$0.13247	0.3%	$0.13254	0.3%	$0.13258	0.3%	$0.13247	0.3%
Agriculture	$0.11704	$0.11844	1.2%	$0.11803	0.9%	$0.11822	1.0%	$0.11835	1.1%	$0.11802	0.8%
E-20	$0.10235	$0.10269	0.3%	$0.10260	0.2%	$0.10264	0.3%	$0.10267	0.3%	$0.10259	0.2%
Total Bundled Change	$0.12770	$0.12870	0.8%	$0.12842	0.6%	$0.12855	0.7%	$0.12864	0.7%	$0.12840	0.5%
Direct Access Service											
Residential	$0.08441	$0.08566	1.5%	$0.08530	1.1%	$0.08547	1.3%	$0.08559	1.4%	$0.08528	1.0%
Small Light and Power	$0.08374	$0.08473	1.2%	$0.08445	0.8%	$0.08458	1.0%	$0.08468	1.1%	$0.08443	0.8%
Medium Light and Power	$0.06545	$0.06610	1.0%	$0.06592	0.7%	$0.06601	0.9%	$0.06607	0.9%	$0.06591	0.7%
E-19 Class	$0.06086	$0.06146	1.0%	$0.06128	0.7%	$0.06136	0.8%	$0.06142	0.9%	$0.06127	0.7%
Agriculture	$0.06258	$0.06323	1.0%	$0.06304	0.7%	$0.06312	0.9%	$0.06318	1.0%	$0.06304	0.7%
E-20	$0.03968	$0.03986	0.5%	$0.03980	0.3%	$0.03984	0.4%	$0.03985	0.4%	$0.03980	0.3%
Total Direct Access Change	$0.04864	$0.04900	0.7%	$0.04889	0.5%	$0.04894	0.6%	$0.04897	0.7%	$0.04888	0.5%
	$0.11859	$0.11951	0.8%	$0.11925	0.6%	$0.11937	0.7%	$0.11946	0.7%	$0.11923	0.5%

Residential Average Bill Change	Present Bill ($)	Year 1 Illustrative Bill ($)	Year 1 Change from Present Bill ($)	Year 2 Illustrative Bill ($)	Year 2 Change from Present Bill ($)	Year 3 Illustrative Bill ($)	Year 3 Change from Present Bill ($)	Year 4 Illustrative Bill ($)	Year 4 Change from Present Bill ($)	Year 5 Illustrative Bill ($)	Year 5 Change from Present Bill ($)
540 kWh	$66.10	$66.25	$0.15	$66.21	$0.11	$66.23	$0.13	$66.24	$0.14	$66.21	$0.11
840 kWh	$121.89	$123.37	$1.48	$122.95	$1.06	$123.15	$1.25	$123.29	$1.40	$122.93	$1.04
1000 kWh	$156.45	$159.02	$2.57	$158.29	$1.83	$158.63	$2.17	$158.87	$2.42	$158.25	$1.80

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX G

GAS COST ALLOCATION AND ILLUSTRATIVE RATES

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
ALLOCATION OF YEAR TWO GAS AMI PROJECT REVENUE REQUIREMENT TO CUSTOMER CLASSES AND ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES ($THOUSANDS, $/THERM)

Line No.	Customer Class	Year Two Gas AMI Project Revenues (000's)	Present Rates ($/therm)	Year Two Proposed Rates ($/therm)	% Change
1	<u>Bundled – Retail Core</u>(a)				
2	Residential	$21,798	$1.117	$1.127	0.9%
3	Small Commercial	5,319	$1.082	1.090	0.8%
4	Large Commercial	87	$0.899	0.903	0.4%
5	<u>Transportation Only – Retail Core</u>(b)				
6	Residential	305	$0.386	0.396	2.6%
7	Small Commercial	1,320	$0.359	0.367	2.3%
8	Large Commercial	20	$0.201	0.205	1.8%
9	<u>Transportation Only – Retail Noncore</u>(b)				
10	Industrial – Distribution	44	$0.120	0.120	0.1%
11	Industrial – Transmission	212	$0.042	0.043	0.3%
12	Industrial – Backbone	0	$0.024	0.024	0.0%
13	Electric Gen. – Dist/Transmission	0	$0.016	0.016	0.0%
14	Electric Gen. – Backbone	0	$0.001	0.001	0.0%
15	<u>Transportation Only – Wholesale</u>(b)	0	$0.017	0.017	0.0%
16	Total	$29,105			

(a) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.615 per therm; (ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(b) Transportation Only rates include: (i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transport only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(c) Percentage change differences are due to rounding of rates to three digits for illustrative presentation.

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
ALLOCATION OF YEAR THREE GAS AMI PROJECT REVENUE REQUIREMENT TO CUSTOMER CLASSES AND ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES ($THOUSANDS, $/THERM)

Line No.	Customer Class	Year Three Gas AMI Project Revenues (000's)	Present Rates ($/therm)	Year Three Proposed Rates ($/therm)	% Change
1	Bundled – Retail Core(a)				
2	Residential	$29,763	$1.117	$1.131	1.2%
3	Small Commercial	7,263	$1.082	1.093	1.1%
4	Large Commercial	117	$0.899	0.904	0.6%
5	Transportation Only – Retail Core(b)				
6	Residential	416	$0.386	0.399	3.5%
7	Small Commercial	1,802	$0.359	0.370	3.2%
8	Large Commercial	28	$0.201	0.206	2.5%
9	Transportation Only – Retail Noncore(b)				
10	Industrial – Distribution	59	$0.120	0.120	0.1%
11	Industrial – Transmission	289	$0.042	0.043	0.4%
12	Industrial – Backbone	0	$0.024	0.024	0.0%
13	Electric Gen. – Dist/Transmission	0	$0.016	0.016	0.0%
14	Electric Gen. – Backbone	0	$0.001	0.001	0.0%
15	Transportation Only – Wholesale(b)	0	$0.017	0.017	0.0%
16	Total	$39,737			

(a) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.615 per therm; (ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(b) Transportation Only rates include: (i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transport only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(c) Percentage change differences are due to rounding of rates to three digits for illustrative presentation.

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
ALLOCATION OF YEAR FOUR GAS AMI PROJECT REVENUE REQUIREMENT TO CUSTOMER CLASSES AND ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES ($THOUSANDS, $/THERM)

Line No.	Customer Class	Year Four Gas AMI Project Revenues (000's)	Present Rates ($/therm)	Year Four Proposed Rates ($/therm)	% Change
1	Bundled – Retail Core(a)				
2	Residential	$39,606	$1.117	$1.135	1.6%
3	Small Commercial	9,664	$1.082	1.097	1.4%
4	Large Commercial	156	$0.899	0.906	0.7%
5	Transportation Only – Retail Core(b)				
6	Residential	553	$0.386	0.404	4.7%
7	Small Commercial	2,398	$0.359	0.374	4.3%
8	Large Commercial	37	$0.201	0.208	3.3%
9	Transportation Only – Retail Noncore(b)				
10	Industrial – Distribution	79	$0.120	0.120	0.2%
11	Industrial – Transmission	385	$0.042	0.043	0.6%
12	Industrial – Backbone	0	$0.024	0.024	0.0%
13	Electric Gen. – Dist/Transmission	0	$0.016	0.016	0.0%
14	Electric Gen. – Backbone	0	$0.001	0.001	0.0%
15	Transportation Only – Wholesale(b)	0	$0.017	0.017	0.0%
16	Total	$52,878			

(a) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.615 per therm; (ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(b) Transportation Only rates include: (i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transport only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(c) Percentage change differences are due to rounding of rates to three digits for illustrative presentation.

PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
ALLOCATION OF YEAR FIVE GAS AMI PROJECT REVENUE REQUIREMENT TO CUSTOMER CLASSES AND ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES ($THOUSANDS, $/THERM)

Line No.	Customer Class	Year Five Gas AMI Project Revenues (000's)	Present Rates ($/therm)	Year Five Proposed Rates ($/therm)	% Change
1	Bundled – Retail Core(a)				
2	Residential	$39,999	$1.117	$1.135	1.6%
3	Small Commercial	9,761	$1.082	1.097	1.4%
4	Large Commercial	159	$0.899	0.906	0.8%
5	Transportation Only – Retail Core(b)				
6	Residential	558	$0.386	0.404	4.7%
7	Small Commercial	2,422	$0.359	0.374	4.3%
8	Large Commercial	37	$0.201	0.208	3.4%
9	Transportation Only – Retail Noncore(b)				
10	Industrial – Distribution	80	$0.120	0.120	0.2%
11	Industrial – Transmission	389	$0.042	0.043	0.6%
12	Industrial – Backbone	0	$0.024	0.024	0.0%
13	Electric Gen. – Dist/Transmission	0	$0.016	0.016	0.0%
14	Electric Gen. – Backbone	0	$0.001	0.001	0.0%
15	Transportation Only – Wholesale(b)	0	$0.017	0.017	0.0%
16	Total	$53,405			

(a) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.615 per therm; (ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(b) Transportation Only rates include: (i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transport only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(c) Percentage change differences are due to rounding of rates to three digits for illustrative presentation.

Application: 07-12-
(U 39 E)
Exhibit No.: (PG&E-4)
Date: December 12, 2007
Witness: Ronald R. Helgens
Nielson D. Jones

PACIFIC GAS AND ELECTRIC COMPANY

SMARTMETER™ PROGRAM UPGRADE

PREPARED TESTIMONY

COST RECOVERY AND REVENUE REQUIREMENTS

(PG&E-4)

PACIFIC GAS AND ELECTRIC COMPANY
SMARTMETER™ PROGRAM UPGRADE
COST RECOVERY AND REVENUE REQUIREMENTS

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

COST RECOVERY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
COST RECOVERY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
COST RECOVERY

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E or the Company) proposal for cost recovery of the SmartMeter™ Program Upgrade. The proposal continues the existing cost recovery mechanism for the SmartMeterProgram, as described in Decision 06-07-027, with adjustments based on the incremental costs and benefits of the SmartMeter Program Upgrade. Specifically, PG&E proposes the following ratemaking treatment:

- Rates will be set initially to recover forecasted project costs, including the incremental costs and benefits of the SmartMeter Program Upgrade; with true-up to actual costs achieved through the existing SmartMeter Balancing Account – Electric (SBA-E).
- The California Public Utilities Commission (CPUC or Commission) will review forecasted incremental costs in this application and, as a result of that review, these forecasted costs will be deemed reasonable and will not be subject to after-the-fact reasonableness review. If actual costs exceed the forecast, then PG&E proposes to file for recovery of the difference through a traditional after-the-fact reasonableness review filing.
- Costs associated with the SmartMeter Program Upgrade incurred prior to a Commission decision of this application and recorded in a memorandum account, upon approval of the advice letter filed concurrently with this application, will also be reviewed in this application, and as a result of that review, these incurred costs will be deemed reasonable and will be transferred to the SBA-E for recovery.
- Incremental benefits or cost reductions will also be reviewed in this proceeding, and specified pre-approved forecasted benefits will be incorporated into rates through the SBA-E as associated project milestones are met.

- Rates covering the SmartMeter Program Upgrade, including the incremental costs and benefits, will be revised annually in the Annual Electric True-Up advice letter, or as otherwise authorized by the Commission.

This means of cost recovery for the SmartMeter Program Upgrade fairly balances risks between customers and shareholders. As ordered in Decision 06-07-027,[1] PG&E will present testimony in the next General Rate Case (GRC) concerning the continuation of the balancing accounts as an alternative to traditional ratemaking treatment.

B. Cost Recovery Proposal

As described in Exhibit (PG&E-1), of this application, PG&E is seeking authority to proceed with an upgrade to the SmartMeter Program approved in Decision 06-07-027.

In order to maintain deployment progress and incorporate available technology upgrades, PG&E must sign contracts with and make commitments to various vendors for products and services with significant costs that are incremental to those approved by the Commission in Decision 06-07-027. Prior to receiving Commission approval for these incremental expenses, PG&E proposes to track these expenditures in a memorandum account described in the advice letter filed concurrently with this application.

PG&E requests that the proceeding for the review of this application and the resulting Commission decision be expedited in order to minimize the interest accrued on the incremental SmartMeter Program Upgrade expenses and the resultant customer impact.

PG&E proposes that the SmartMeter Program budget be increased from the previously authorized $1,739.4 million by an additional $622.7 million, with the inclusive Risk Based Allowance increased commensurate with the identified risks from $128.8 million by an additional $66.9 million.

PG&E proposes that rates be revised for the years 2009 through 2010 based on the revenue requirements (that include the incremental SmartMeter Program Upgrade costs less forecasted specified benefits) presented in Chapter 2 of this exhibit. PG&E proposes to recover these SmartMeter Program Upgrade costs from customers in the same manner as adopted in

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[1] D.06-07-027, OP 15, p. 68.

Decision 06-07-027 for other SmartMeter Program costs. That is, the total revenue requirement will be recovered in the same manner as other distribution revenue, based on the distribution revenue allocation and rate design methods authorized by the Commission at that time.

Forecasted revenue requirements for the years 2011 and beyond are also shown in Chapter 2 for illustrative purposes. PG&E will propose the cost recovery mechanism for 2011 through 2013 (or through whatever final year is proposed) in PG&E's next GRC, as ordered by Decision 06-07-027.[2]

1. Monthly Calculation

As described in the approved SBA-E Preliminary Statement, PG&E proposes to continue to record the following items into the SBA-E:

a. Capital-related revenue requirements (debit), calculated on actual recorded plant additions;

b. Actual Operations and Maintenance (O&M) costs (debit), calculated on recorded expenses;

c. Calculated benefits (credit), as described below; and

d. Actual SmartMeter Program revenues (credit) based on the SmartMeter rate components from Preliminary Statement, Part I, which is set based on the revised revenue requirements approved in this proceeding.

2. Cost Reasonableness

As in Decision 06-07-027, PG&E requests that the Commission find the revised SmartMeter Program Upgrade budget to be reasonable so long as the actual cost of the SmartMeter Program Upgrade is equal to or less than the forecast set forth herein. This assurance of reasonableness is essential to the timely cost recovery needed to ensure PG&E's credit quality. SmartMeter Program Upgrade costs would still be subject to review and verification to ensure that recorded expenses were correctly assigned to SmartMeter Program Upgrade activities.

If actual costs exceed the adopted cost estimate, PG&E proposes to seek recovery of the difference through a traditional after-the-fact reasonableness review process.

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[2] D.06-07-027, OP 15, p. 68.

C. Benefits Recognition Proposal

PG&E proposes to continue the current mechanism for recognizing benefits resulting from the project on a monthly basis as meters are activated and project milestones are achieved. PG&E requests that the benefit calculation be adjusted to reflect the additional operational benefits associated with the SmartMeter Program Upgrade. These benefits are summarized in Exhibit (PG&E-3), Chapter 1.

Some resultant benefits are not included in the benefit credit calculation for the balancing account. Specifically, the demand response benefits are not included in this calculation since these benefits do not result in a reduction to utility operating costs. Tax benefits associated with meter retirements are also excluded from this calculation because they are captured in the recorded revenue requirements. All of the incremental operational benefits resulting from the SmartMeter Program Upgrade are associated with the integrated load limiting connect/disconnect switches, and are proportional to the number of meters installed and activated, once the connect/disconnect functionality is enabled through PG&E systems. PG&E expects the remote connect/disconnect functionality to be available in the latter half of 2009. For 2009-2010, PG&E expects to accrue incremental benefits averaging $0.1821 per active electric meter per month (see table below). Once the remote connect/disconnect functionality has been activated, PG&E proposes to adjust the existing per electric meter monthly benefits calculation from $1.7722 per active electric meter per month by an additional $0.1821 per active electric meter per month, to be in effect through the end of 2010.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE INCREMENTAL BENEFITS CALCULATION

Line No.		Electric Benefits
1	Incremental Benefits Proportional to Meter Activation	
2	2009	$1,574,000
3	2010	7,765,000
4	Total Incremental Meter Activation Benefits	$9,339,000
		Electric Meters
5	Average Active Meters	
6	2009	$993,000
7	2010	3,280,000
8	Total Active Meter Years	$4,273,000
9	Average Incremental Benefits Per Active Meter Year (2009-2010)	$2.1856
10	Average Incremental Benefits Per Active Meter Month (2009-2010)	$0.1821

PG&E will address any benefit savings achieved after 2010 in either the PG&E Test Year 2011 GRC or in another mechanism available at that time.

D. Potential for Interim Cost Recovery and Future Technology Upgrades

If the CPUC has not determined its final decision in this application prior to PG&E's need for funding to proceed with upgrades to the SmartMeter Program, PG&E may ask the CPUC to create an interim funding review process so that the SmartMeter Program Upgrade can continue on schedule.

E. Conclusion

PG&E requests cost recovery for the SmartMeter Program Upgrade using adjustments to the cost entries and benefits calculations of the existing SmartMeter balancing accounts. The proposed adjustments to these accounts would cover the actual incremental costs incurred for the SmartMeter Program Upgrade, net of the forecasted incremental benefits as described in this chapter. Prior to receiving Commission approval for incremental expenditures for the SmartMeter Program Upgrade, PG&E proposes to track these expenditures in a memorandum account described in the advice letter filed concurrently with this application.

A full review of forecasted incremental costs and benefits will take place as part of this application process, and once these forecasts have been reviewed and adopted, no further reasonableness review need occur, unless PG&E seeks cost recovery in excess of the amounts reviewed here.

For the entire SmartMeter Program, PG&E will continue to adjust gas and electric rates according to the year-end balances in the SmartMeter balancing accounts in the Annual Electric True-up (AET) and Annual Gas True-up (AGT) advice letters, or as otherwise authorized by this Commission.

PG&E seeks approval of this proposed cost recovery process for the SmartMeter Program Upgrade.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REVENUE REQUIREMENT (ELECTRIC)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
REVENUE REQUIREMENT (ELECTRIC)

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
REVENUE REQUIREMENT (ELECTRIC)

A. Introduction

The purpose of this chapter is to present forecasted, incremental annual revenue requirements needed to fund Pacific Gas and Electric Company's (PG&E or the Company) SmartMeter™ Program Upgrade. These revenue requirements are based on incremental costs that were not included in PG&E's Advanced Metering Infrastructure (AMI) case or requested in PG&E's 2007 General Rate Case (GRC). PG&E proposes that the SmartMeter Program Upgrade be subject to cost recovery with a balancing account as discussed in Exhibit (PG&E-4), Chapter 1 at least until the next GRC.

The revenue requirement calculations presented here compile all capital-related costs, operating expenses and benefits into an income statement format to estimate the additional amount of revenue needed to recover the cost of the SmartMeter Program Upgrade deployment. This amount of revenue is known as the revenue requirement or cost of service; and, since the income statement format is utilized, the model is known as the Results of Operations (RO).

PG&E is presenting these forecasted revenue requirements for several reasons:

- PG&E requests that initial rates for project deployment, to be effective January 1, 2009, be set based on the revenue requirements presented here, although ultimately PG&E proposes to recover actual costs of the project;
- PG&E also requests that SmartMeter Program Upgrade rates be changed January 1 of 2010, based on the revenue requirement presented here, plus balancing account balances calculated at the time the rate change is requested;
- PG&E asks that the RO model assumptions and methods used to calculate the capital revenue requirements discussed herein be approved for calculating monthly capital revenue requirements based on recorded SmartMeter Program Upgrade plant;

- To show how the incremental costs presented in Exhibit (PG&E-3) translate into revenue increases; and
- To provide forecasted revenue requirements for the calculation and evaluation of rate impacts.

PG&E's cost recovery proposal seeks to recover the entire costs of the SmartMeter Program Upgrade from customers. PG&E requests that the California Public Utilities Commission (CPUC or Commission) approve the use of the revenue requirements set forth here to establish rates.

B. Summary of Revenue Requirement Results

PG&E estimated incremental SmartMeter Program Upgrade annual revenue requirements for the deployment phase of this project, beginning in 2008, and continuing for 15 years. SmartMeter Program Upgrade cost recovery through rates will not begin until 2009 and, therefore, the deployment costs occurring in 2008 will be referred to as Year 0 costs. For the initial rate change requested for January 1, 2009, PG&E has calculated a $34.3 million revenue requirement. This revenue requirement is the sum of the Year 0 and Year 1 revenue requirements, $6.75 million and $27.51 million, respectively. The 2010 revenue requirement request is $56.5 million based on the costs and operational benefits incurred during the year, Year 2.

A summary of the revenue requirements for the first five years of cost recovery is shown in Table 2-1, below. These revenue requirements are based on all cash flows without exclusion for costs that may be recovered in future GRCs. It is anticipated that after the second year of cost recovery, 2010, rates for SmartMeter Program Upgrade would be rolled into the 2011 GRC or continued through an appropriate mechanism. The revenues shown beyond 2010 are essentially for illustrative purposes to show the total five-year project cost recovery.

TABLE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
FORECASTED REVENUE REQUIREMENTS FOR SMARTMETER PROGRAM UPGRADE
($ IN THOUSANDS)

Line No.	Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
1	Electric RRQ	$6,751	$27,514	$56,468	$82,832	$99,169	$83,587

The revenue requirements shown for Year 0 through Year 2, along with the balances in the balancing accounts, will be used to set the SmartMeter Program Upgrade rates under PG&E's proposal in Exhibit (PG&E-4), Chapter 1. Forecasted revenue requirements for the remaining years are located in PG&E's workpapers.

C. Description of Incremental SmartMeter Program Upgrade Costs

1. Summary

The net incremental SmartMeter Program Upgrade revenue requirements reflect the capital costs, operating expenses and benefits described in the Present Value Revenue Requirement (PVRR) model, described in Exhibit (PG&E-3), Project Costs and Benefits. The PVRR analysis uses a cash-flow approach in analyzing the cost and benefits from the SmartMeter Program Upgrade. In this exhibit, PG&E presents the costs in a regulatory (cost recovery) format. For this analysis, PG&E groups the costs into capital-related and expense-related categories. Operations benefits are modeled using expense-related categories.

Demand response-related benefits (avoided procurement, transmission and distribution) discussed in Exhibit (PG&E-3) are not included in PG&E's net revenue requirements, since these benefits are dependant on customer behavior and should not be viewed as a utility cost saving unless they materialize in the future. To the extent these savings occur, they will be reflected in customer rates at that time through the appropriate regulatory proceedings in the future.

2. Capital Costs

This section describes the capital additions related to the SmartMeter Program Upgrade. Capital costs are grouped by the following classifications: (1) Electric Meters; (2) Communication Devices;

(3) Information Technology (IT) – Hardware; and (4) IT – Programming and Management. These classifications have certain tax treatment as discussed in Section D.4.

3. Retirements of Plant

As the new solid state meters are deployed, replaced existing meters will be retired at their original cost. The retirement of these 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 remaining plant investment will be recovered over the remaining life of the depreciation group.

For federal tax, a deferred tax benefit associated with the early retirement of existing meters has been included in the revenue requirements calculation as a negative operating expense. No adjustments were made in the RO calculations for salvage and removal costs of the retired meters, thus assuming the salvage value equals removal costs. However, when the recorded costs are included in the balancing accounts, recorded salvage values and removal costs will be reflected.

4. Operating Expenses and Benefits

The majority of these expenses are labor required to support the software and hardware required for the project as discussed in Chapter 3 of Exhibit (PG&E-3). The incremental PG&E labor includes standard burdens such as payroll taxes and direct benefits. Indirect employee benefits such as those associated with post-retirement, long-term disability, workers compensation, and casualty insurance are excluded. Existing balancing account mechanisms already include these costs so the balancing account revenue requirement for the SmartMeter Program Upgrade excludes them.

The SmartMeter Program Upgrade operational benefits are deducted from the (gross) revenue requirement to determine the net revenue requirement. These savings include: (1) labor savings; (2) improved cash flows; and (3) reduced bad debt. In the revenue requirement calculations, these savings are reflected as negative operating expenses.

D. Elements of the Results of Operation Calculation

The SmartMeter Program Upgrade revenue requirements calculations show the revenues PG&E needs to cover the expense-related and capital-related costs expected to be incurred over the SmartMeter Program Upgrade planning horizon. In addition to the expenses described above, expense-related costs also include property, business and other taxes, which are based on the currently effective tax rates. PG&E applied a franchise fees and uncollectible (FF&U) factor of 0.010151 (electric) to the entire revenue requirement. This FF&U factor was agreed upon in PG&E's 2007 GRC Settlement Agreement. The various capital-related components of the RO calculation are discussed below.

1. Depreciation

Depreciation is included in the cost of service calculations as both depreciation expense and accumulated depreciation.

Depreciation expense is calculated using depreciation accrual rates based on the straight line, remaining life method in accordance with the CPUC Standard Practice U-4, *Determination of Straight Line Remaining Life Depreciation Accruals*. Depreciation measures the loss of value in tangible assets that occurs as the assets are used up over time. Depreciation expense represents the amount of that value recognized in a given year for recovery of prior capital investment. It is through depreciation expense, net of salvage value, that a utility recovers its original capital investment through rates.

PG&E classified the capital additions by plant type, thereby assigning the appropriate depreciation rate and service life. These classifications include: (1) Electric Meters; (2) Communication Devices; (3) IT Hardware; and (4) IT Programming and Management. The electric meter category includes the cost of the solid state meter as well as the remote connect/disconnect switch. The communication device category includes the Home Area Network (HAN) gateway device. For each classification, PG&E estimates depreciation expense by multiplying the weighted average plant in service by the corresponding book depreciation rates from the May 1, 2007, depreciation accrual rate schedules filed with the CPUC. By using the current depreciation schedule, PG&E is currently basing the future life of the new meter technology on what is essentially a study of incumbent (older) technology. It is anticipated that the new meter technology will actually have a shorter anticipated life then the incumbent technology. Future depreciation rates as approved will be incorporated into the balancing account calculation of the monthly capital revenue requirement based on recorded plant. Table 2-2 summarizes the depreciable lives and depreciation rates that PG&E proposes for its SmartMeter Program Upgrade assets.

TABLE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
BOOK DEPRECIATION ASSUMPTIONS

Line No.	Asset	Life	Rate
1	Electric Meters	30	3.27
2	Communication Devices	20	5.00
3	IT Hardware	15	6.67
4	IT Programming and Management	15	6.67

Accumulated depreciation is calculated by adding estimated depreciation expense and net salvage value to the prior year's end-of-year reserve balance and subtracting the forecast asset retirements.

2. Rate Base

The elements of rate base included for SmartMeter Program Upgrade costs are: utility plant in service plus working capital, less deferred taxes, less accumulated depreciation. Utility plant in service consists of the accumulated original undepreciated investment in plant and equipment that is used and useful in rendering the services that are required by the SmartMeter Program Upgrade. In developing the associated rate base, certain deductions are made. A deduction is made for the accumulated deferred taxes associated with these assets. These deferred taxes result from following the Modified Accelerated Cost Recovery System (MACRS) tax depreciation method for federal income tax purposes. Due to the timing differences that result from the use of this tax depreciation method, taxes that have been paid for by the customer are not paid to the Internal Revenue Service (IRS) until a later date. Finally, plant is reduced by the amount of depreciation reserve (i.e., the accumulated depreciation already taken in prior years).

3. Rate of Return

PG&E multiplies the currently adopted composite rate of return of 8.79 percent by the SmartMeter Program Upgrade average rate base for each year to calculate the return on rate base. This calculation uses the rate of return and capital ratios adopted in PG&E's 2006 cost of capital decision (D.05-12-043) and 2007 cost of capital decision (D.06-08-026). The 2008 PG&E cost of capital proposed decision is expected to be voted out on December 20, 2007. The balancing account will incorporate the latest authorized rate of return for capital revenue requirements based on recorded SmartMeter Program Upgrade plant.

4. Income Tax Depreciation Assumptions

This section describes the assumptions and calculations used in the revenue requirements calculations to estimate income tax depreciation. PG&E estimates California Corporation Franchise Taxes (CCFT) and federal income taxes on net operating income before income taxes. Federal income tax expense is the product of the currently effective corporate income tax rate (35 percent) and federal taxable income. Likewise, state income tax expense is the product of the statutory rate (8.84 percent) and the state taxable income.

Federal income taxes are computed on a normalized basis. This allows PG&E to recognize the timing differences between book and federal tax depreciation. This difference times the federal tax rate is called deferred federal income taxes, and is included as a credit to rate base. The IRS may accelerate the depreciation period for certain advanced metering property in the future. If shortened depreciation period is approved, PG&E proposes to make adjustments to the balancing account to account for the benefit.

State income taxes are calculated on a flow-through basis. Therefore, the customers receive an immediate benefit from the use of accelerated state tax depreciation. There is no associated rate base deduction for deferred state taxes.

PG&E followed MACRS and Asset Depreciation Range (ADR)[1] guidelines for classifying SmartMeter Program Upgrade capital additions and calculating federal and state tax depreciation. All acquired software is capitalized for tax depreciation, and therefore generates tax depreciation and deferred tax expense when it is booked as an expense.[2] Internally developed software is expensed for tax purposes. Table 2-3 summarizes the federal and state tax depreciation methods used in the RO calculations.

TABLE 2-3
PACIFIC GAS AND ELECTRIC COMPANY
TAX ASSUMPTIONS

Line No.	Asset	Federal Tax Method	State Tax Method
1	Electric Meters	20-Year MACRS	30-Year ADR_SYD
2	Communication Devices	20-Year MACRS	30-Year ADR_SYD
3	IT Hardware	5-Year MACRS	6-Year ADR_SYD
4	IT Programming and Management	Expensed	Expensed
5	Software	3-Year Straight Line	3-Year Straight Line

E. Conclusion

In calculating the revenue requirements presented in this chapter for the SmartMeter Program Upgrade, PG&E has used methods and factors consistent with those used in preparing its AMI and GRC filings. Only the timing of this project required it to be presented separately. Costs, benefits and revenues will be rolled into PG&E's next GRC if appropriate. While PG&E recommends separate cost and revenue accounting for the SmartMeter Program Upgrade, the costs will be recorded into the appropriate (Federal Energy Regulatory Commission) functional accounts. In a GRC, these SmartMeter Program Upgrade costs would be presented in PG&E's electric distribution unbundled cost categories since these types of costs are typically considered part of the electric distribution revenue requirements. As noted in Chapter 1 of this exhibit, PG&E proposes that all costs for SmartMeter Program Upgrade be paid for by electric distribution customers through increased rates.

[1] Uses Sum of Years Digits (SYD) method.

[2] Software exceeding a $5 million threshold is capitalized for book depreciation.

TAB C

SCE GRC Transcript
Dated June 12, 2008
(See Marked Pages 1768 to 1770)

SAN FRANCISCO, CALIFORNIA, JUNE 12, 2008 - 12:05 P.M.

* * * * *

ADMINISTRATIVE LAW JUDGE DE ANGELIS: On the record.

Good afternoon. I hope everyone had a nice early lunch.

We have Edison's next witness, but before we start, Mr. McNulty, do you want to clarify an issue?

MR. MC NULTY: Thank you, your Honor.

On June 10th, you had asked us a couple of followup questions on where in our showing we responded to some directives in the Commission's decision from our 2006 rate case, and I had provided you information on one of those items earlier this week, and one of them was still pending.

The pending item was in the text of Decision 06-05-016 at page 185. It's also found in Conclusion of Law 31 from that decision that states: In its next GRC, SCE should provide full, transparent and understandable information on the present and future market value of the retirement severance benefits of its top executives.

We did provide information on that on page 86 of Exhibit SCE-06B; however, upon further review and reflection on that, we acknowledge that the information we provided probably fell short of the full, transparent and understandable portion of that directive. We did provide the dollar amount and some brief discussion about that benefit; however, we didn't provide any supporting workpapers or derivation of the number.

So what we're proposing to do to remedy that is to provide a supplemental exhibit today that quantifies how the numbers were calculated.

I should also caveat that by saying that the calculation presented on the page I just referenced was done at a particular moment in time. It's a calculation of present value. We redid the calculation based on a different date, so the number won't match, but the information, we believe, will now be as responsive as we can to the directive from that decision.

There's still a bit of confusion or, I might say, we're a little bit perplexed about whether -- exactly how to comply with that directive. But we want to thank you for pointing that out to us. It gave us an opportunity while the record was still open to go back and revisit that issue.

So that supplemental testimony will be served to all parties today, and we should have some copies of it for the people in the hearing room later today.

ALJ DE ANGELIS: Okay. Thank you, Mr. McNulty.

All right. Anything else before we start with Edison's next witness?

(No response)

ALJ DE ANGELIS: Okay. Would you like to call your next witness.

MR. MC NULTY: Thank you, your Honor.

At this time, Edison calls Mr. Richard Fisher.

ALJ DE ANGELIS: May I swear you in?

RICHARD FISHER, called as a witness by Southern California Edison Company, having been sworn, testified as follows:

ALJ DE ANGELIS: Thank you.

Please have a seat. State your name and business address for the record.

THE WITNESS: My name is Richard Fisher, F-i-s-h-e-r. My business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

ALJ DE ANGELIS: Thank you.

DIRECT EXAMINATION

BY MR. MC NULTY:

Q Mr. Fisher, directing you to what's been identified as Exhibit SCE-11B, do you recognize that as containing your -- portions of your prepared testimony in this proceeding?

A Yes.

Q And your witness qualifications are as set forth in Appendix A to this exhibit?

A Yes.

Q Also directing you to Exhibit SCE-11C, that contains additional prepared direct testimony you're sponsoring?

A Yes.

Q Next, directing you to Exhibit SCE-16G, this contains portions of your rebuttal testimony in this proceeding?

A Yes.
Q Exhibit SCE-17H-1 contains additional rebuttal testimony you are sponsoring?
A Yes.
Q Exhibit SCE-24A, again additional rebuttal testimony sponsored by you?
A Yes.
Q Exhibit SCE-24B contains your rebuttal on the depreciation study?
A Correct.
Q Exhibit SCE-29 contains your errata?
A Yes.
Q And also there is errata sponsored by you in Exhibit SCE-31?
A Yes.
Q With the errata we have just mentioned, is the material in all these exhibits true and correct to the best of your knowledge?
A Yes.
Q To the extent it represents your judgment, it's your best judgment?
A Yes.
Q And you now adopt it as your prepared testimony in this proceeding?
A I do.

MR. MC NULTY: Thank you.

Your Honor, Mr. Fisher is available for cross-examination at this time.

ALJ DE ANGELIS: All right. Ms. Tudisco.

MS. TUDISCO: Thank you, your Honor.

If I might, I believe we have an understanding with SCE that DRA will waive its cross-examination of Mr. Fisher if SCE would stipulate to the admission of an exhibit that I handed out at the interval.

I believe it should be marked as DRA 86.

ALJ DE ANGELIS: Okay.

MS. TUDISCO: It is a statement of agreement, Plant Weighting For DRA's Adjustments.

ALJ DE ANGELIS: All right. We'll mark that for identification as DRA 86.

(Exhibit No. DRA-86 was marked for identification.)

MS. TUDISCO: And I would move it into evidence.

ALJ DE ANGELIS: All right. Any objections?

(No response)

ALJ DE ANGELIS: No objections. Your request is granted. Thank you.

(Exhibit No. DRA-86 was received into evidence.)

ALJ DE ANGELIS: Mr. Finkelstein.

MR. FINKELSTEIN: Thank you, your Honor.

CROSS-EXAMINATION

BY MR. FINKELSTEIN:

Q Good afternoon, Mr. Fisher.

A Good afternoon.

Q Let me get you to start with your depreciation study, which I think is marked SCE-11C.

A Yes.

Q And at page 82, lines 7 through 9, talking about how you're estimating future net salvage; do you see that?

A Yes, I do.

Q And you'd agree with me, wouldn't you, that this is an exercise in forecasting the future net salvage cost?

A Correct.

Q And for the plant that's currently in service we're forecasting the future net salvage cost that will be incurred at whatever point in time that plant is taken out of service?

A That is correct.

Q And would you accept subject to check that the remaining service lives for most of Edison's transmission and distribution plant is calculated to be in the 20- to 40-year range?

A Yes, subject to check.

Q You'd agree with me that, all else being held equal, the longer the average service life that's adopted, the lower the depreciation rates would be?

A Yes, all else being equal.

Q And again, all else equal, a lower adopted cost of removal would result in a lower depreciation rate?

A That is correct, all else equal.

Q Would you agree with me that one of the principal disagreements between TURN and Edison is about the treatment of future inflation?

A Yes, I'd agree with that.

Q Let me get you to assume for these next questions that plant is installed this year with a 20-year life. Just as a general matter, is it fair to characterize the Edison approach to calculating the associated net salvage with that plant as estimating the total cost of removing the plant to be incurred 20 years from now and spreading it evenly over the 20-year period?

MR. MC NULTY: Your Honor, could we get a clarification on whether the hypothetical refers to asset class depreciation or specific asset? There's two different methods for calculating depreciation. If we could just get a clarification on what the hypothetical refers to.

MR. FINKELSTEIN: Your Honor, I'm sorry. I thought the hypothetical had been clear about a piece of equipment installed in 2009 with a 20-year life.

THE WITNESS: Well, maybe I can ask, to clarify the question, are you talking about a single piece of equipment that will retire 20 years from now?

MR. FINKELSTEIN: Q Yes.

A Yes, in that case we would estimate the cost 20 years -- as it would be incurred 20 years from now.

Q And then you would recover that cost in equal increments in each of the 20 years?

A That is correct.

Q But if that same piece of equipment for some reason failed almost immediately and had to be removed within a month, there would still be costs for removal incurred, correct?

A Under the existing procedures for depreciation, we would accrue that cost of removal over the existing remaining life of whatever plant, but that assumes group depreciation, not under a single-asset scenario.

Q But for a single asset -- for a single piece of equipment, I mean just as a matter of fact, if you install the equipment and it fails a month later, you've got to remove it and replace it with some new equipment, don't you?

A Typically, yes.

Q Would you agree with me that the amount of inflation that's part of the cost of removal depends on the date of removal?

A Yes, I would agree with that.

Q And it's true, is it not, that in most cases for Edison the retirement and removal of plant in service takes part [sic] as part of replacement activities?

A Yes, a portion of it does.

Q Isn't it the most substantial amount of retirements occur as part of replacement?

A I don't believe we have done any studies to affirm that or not.
Q Do you have any sense of it as you sit here --
A No.
Q -- whether or not that's true?
A I'm sorry, can you repeat the question?
Q I said, do you have any sense of that as you sit here, whether or not that's true?
A I really don't.
Q But it's true, is it not, that the replacement activities -- let me put it this way: Even if Edison never expanded its service beyond its current service territory as of today that the replacement activities would have Edison's rate base continue to grow?
A I think under the assumption that there will be cost escalation in the future, that would be true.
Q And that's because you'd be replacing facilities spending today's dollars when those facilities had been installed in the past when things were cheaper?
A Yes, that is correct.
Q Let me get you to turn to page 72 of the depreciation study.
MR. FINKELSTEIN: I'm sorry, your Honor, can we go off the record for a second?
ALJ DE ANGELIS: Sure.
Off the record, please.
(Off the record)

ALJ DE ANGELIS: All right. Back on the record.

MR. FINKELSTEIN: Q Mr. Fisher, page 72, lines 14 through 17, do you see the reference to an accounting period, and that actually shows up on line 16?

A Yes.

Q For ratemaking purposes, what's the accounting period?

A Well, I think that's a really broad question. I think it needs to be put in context of what type of costs we're talking about in a ratemaking period.

Q Well, for purposes of setting depreciation rates for test year 2009, what's the accounting period?

A I believe the accounting period is the life of the asset.

Q Let me get you to turn to your rebuttal testimony in 24B, and it's actually Attachment D, page D-2.]

Do you have that.

A Yes, I do.

Q And this equation that's towards the top of the page, do you see that?

A Yes.

Q So in this equation, C represents net salvage?

A Average net salvage in percent of plant -- as a percent of be plant.

Q And the 100 represents the plant itself; is that correct?

A Yeah, as a percentage rate of plant.

Q So the 100 represents that the depreciation rate is intended to recover a hundred percent of the original investment added to plant in service when the plant is put in service?

A That is correct.

Q So would you agree with me that sort of applying basic algebra, this equation could be restated as D of equals 100 over L minus C over L?

A I believe that is correct, yes.

Q And I guess for these questions, I need you to assume that gross salvage is zero. Do you have that assumption in mind?

A Yes.

Q So if the plant were removed today, C would be set based on the cost removing the plant in today's dollars; is that correct?

A I'm hesitating because I think that's under the assumption that you knew it was going to be removed today.

Q Well, if you were estimating that the plant were going to be removed ten years from now, C would be the cost of removing the plant today escalated by ten years of inflation?

A Yes, it would be the cost that we would incur in the future.

Q So let me get you to turn to page 9 of your rebuttal testimony table 1-1.

A I'm there.

Q And this was a replication of parts of a table that showed up in TURN's testimony or the exhibits supporting TURN's testimony; is that correct?

A Yes. I believe it's in the exhibits supporting TURN's testimony.

MR. FINKELSTEIN: And your Honor, I had circulated earlier a copy of that portion of TURN's testimony. It's already going to be in the record, so I'm not sure we need to bother doing anything with it now. I just -- I was hoping not to bring up the whole tome.

ALJ DE ANGELIS: Which one was that?

MR. FINKELSTEIN: Exhibit MJM-1, a three-page document with a cover sheet.

ALJ DE ANGELIS: Okay.

MR. FINKELSTEIN: Q Mr. Fisher, the document that has the cover page Exhibit MJM-1, this is the table that you were replicating in your testimony; is that correct?

A Yes, it appears so.

Q And the assumption underlying this testimony was that it would cost $20,000 today to remove the piece of equipment that was being used to illustrate -- I'm sorry -- was the basis of the table?

A Yes.

Q I'm sorry. Is that your understanding?

A Yes, that is my understanding.

Q Now, Mr. Fisher, is it your understanding that in Edison's last general rate case the Commission directed the utility to analyze the effects of past inflation on its proposed cost of removal rates?

A I recall generally, yes.

MR. FINKELSTEIN: I'm sorry, your Honor. Can we go off the record?

ALJ DE ANGELIS: Off the record, please.

(Off the record)

ALJ DE ANGELIS: Back on the record.

MR. FINKELSTEIN: Thank you, your Honor.

Q Let me get you to turn in your depreciation study if I could to page 86, and this is SCE-11C.

A Yes, I'm there.

Q And the last four lines on that page lists five calculations that Edison included for each of its accounts in its net salvage analysis. Do you see that?

A Yes, I do.

Q And the third and fourth refer to calculating the proposed net salvage dollars based on year-end 2006 investment. Do you see that?

A Yes, I do.

Q And then the net salvage in 2006 dollars is item 4?

A Yes.

Q Then as I understand Edison's approach, you compared those two figures over the remaining service life to calculate the implied escalation from the end of 2006 to whatever's the end of the remaining service life?

A That is correct.

Q And that's illustrated on -- I'm sorry. Turning the page to page 87 of your depreciation study, for Account 352, those are the two figures, item 3 and item 4 in the box at the top of the page.
A I'm sorry. Those are what two figures?
Q The ones we were just flipping back to, page 86, items 3 and 4 in this list of items that were in the analysis?
A That is correct.
Q Okay. And to calculate the impact of past inflation, Edison used the Handy-Whitman index; is that correct?
A In part, yes.
Q Let me get you to turn to the excerpt of your workpapers that's been circulated. And I, of course, managed to cut off the page numbers, but the last two pages of the document show a net salvage vintage analysis. Do you see that?
A Yes, I do.
Q And doesn't this set forth how you calculated in this case for Account 365 the net salvage as of 2006?
A Yes.
Q And to do that you took the net salvage at the year of installation and inflated it using the HW escalation factor. Do you see that?
A Yes.
Q And that was the Handy-Whitman escalation factor; is that correct?

A That is correct.

MR. FINKELSTEIN: Let me get you -- I'm sorry.

Your Honor, can we get marked as --

Actually, your Honor, maybe we can take a second and mark all the cross exhibits, just to be done with it.

ALJ DE ANGELIS: Okay, let's do that.

MR. FINKELSTEIN: The next in order should be the Foreword to Handy-Whitman Index.

ALJ DE ANGELIS: Okay. And that would be TURN --

MS. SANCHEZ: 43.

ALJ DE ANGELIS: 43.

(Exhibit No. TURN-43 was marked for identification.)

MR. FINKELSTEIN: Thank you.

ALJ DE ANGELIS: Okay.

MR. FINKELSTEIN: The next in order would be Calculations of Per-Unit Costs of Removal.

ALJ DE ANGELIS: All right. We'll mark that for identification as TURN-44.

(Exhibit No. TURN-44 was marked for identification.)

MR. FINKELSTEIN: After that is one entitled Excerpt from Wolf & Fitch, F-i-t-c-h, Depreciation Systems.

ALJ DE ANGELIS: We'll mark this for identification as TURN-45.

(Exhibit No. TURN-45 was marked for identification.)

MR. MC NULTY: Your Honor, we may have missed getting that copy or misplaced it, but I wonder if we could request another copy.

ALJ DE ANGELIS: Okay.

MR. FINKELSTEIN: (Handing document to Mr. McNulty).

MR. MC NULTY: Thank you.

MR. FINKELSTEIN: Sure.

MR. MC NULTY: And may I have the number on this one.

ALJ DE ANGELIS: TURN-45.

MR. MC NULTY: Thank you.

MR. FINKELSTEIN: The next one is entitled SCE Annual Depreciation Reports to Energy Division 2006, 2007 and 2008.

ALJ DE ANGELIS: Okay, we'll mark that for identification as TURN-46.

(Exhibit No. TURN-46 was marked for identification.)

MR. FINKELSTEIN: And finally, your Honor, there is one entitled TURN -- I'm sorry, SCE Responses to TURN Data Requests.

ALJ DE ANGELIS: Okay. 12 through 10.

MR. FINKELSTEIN: 12 dash 10, et cetera.

ALJ DE ANGELIS: Okay, we'll mark that for identification as TURN-47.

(Exhibit No. TURN-47 was marked for identification.)

MR. FINKELSTEIN: Thank you.

Q Mr. Fisher, let me get you to turn to what's been marked as TURN-43. And do you recognize this as the foreword to the Handy-Whitman index?

A You know, I have to be honest: We got this this morning. There must have been something going on with the fax process, so this is really my first time seeing it.

Q But you've seen the Handy-Whitman index itself, have you not?

A I used the index numbers. I haven't seen the actual printed document, if this is part of it.

Q Okay. And the index numbers, would you agree, are a relatively mind-numbing list of factor after factor after factor for each of the accounts?

A Yes.

Q Well, would you accept subject to check that the two pages copied here are out of the foreword of the Handy-Whitman index materials?

A Yes, I'll accept that subject to check.

ALJ DE ANGELIS: Is there a date of publication?

MR. FINKELSTEIN: Your Honor, at the bottom of the second page --

ALJ DE ANGELIS: Okay.

MR. FINKELSTEIN: -- it shows May 2007.

ALJ DE ANGELIS: Thank you.

MR. FINKELSTEIN: Q On the first page of text, Mr. Fisher, you see in the upper right-hand column a sentence that refers to construction cost data?

A Yes.

Q And then about in the middle of the column, it describes how index numbers have been developed for a number of things that include electric utility construction?

A Yes, I see that.

Q And the sentence after that refers to prices and materials such as cement, sand, gravel, and cast iron pipe?

A Yes, I see that.

Q Turning to the second page, do you see -- it's the second paragraph from the bottom on the left hand column, a reference to the building construction cost trends?

A Yes, I see that.

Q And then under the heading Value of Index Numbers in the right hand column, it describes calculating the present day cost of any property?

A Yes, I see that.

Q And in your depreciation study at page 70, the first line, you point out that removal cost is mostly labor?]

A I'm sorry, can you point me to the line again.

Q It is SCE-11C, page 70, top of the page.

A Yes, I see that.

Q Would cost removal include materials such as

sand, gravel or cast-iron pipe ever?
A Not that I'm aware of. Except for there is certain costs for retirement of gas pipelines that may involve slurring the sediment pipeline or using other construction, materials of that sort.
Q I'm sorry, that would be for pipeline?
A That is an example that I can think of right off the top of my head, yes.
Q I'm trying to remember your Catalina operations. Does Edison have any gas pipeline?
A It does in Catalina.
Q Then is it fair to say that the Handy-Whitman Index doesn't measure the cost escalation that Edison itself actually experienced in the last 15 years?
A That is my understanding, yes.
Q It is intended to be sort of an industry-wide measure?
A Yes.
Q And it has got regional numbers to reflect different regions of the country?
A That is my understanding, yes.
Q Exhibit 11-C, page 3 of your depreciation testimony -- I'm sorry, your Honor, can we go off the record?
ALJ DE ANGELIS: Off the record, please.
(Off the record)
ALJ DE ANGELIS: On the record.
MR. FINKELSTEIN: Q Mr. Fisher, for a number of

the T&D accounts your depreciation study calculated the average unit removal cost; is that correct?

A Yes.

Q And that was intended to serve as some sort of check on the reasonableness of the removal cost that Edison was recording?

A Yeah, in part that is why we did that analysis.

Q Let me get you to turn in 11-C to page 114. This is for Account 365; is that correct?

A Yes, that is a distribution conductor.

Q And Figure Roman 5-10 shows the cost of removal per unit from 1992 through 2006?

A It shows a four-year rolling average of cost removal per unit for those time periods.

Q And did you use a four-year rolling average to smooth out some of the year-to-year fluctuations?

A Yes.

Q And for us utility neophytes still, distribution conductor is basically what is hanging off a distribution pole, the cable running back and forth?

A Correct, that is what the electricity flows through.

Q And what your table -- I'm sorry, what your figure here shows is that the average cost per unit in 1992 through 1995 was a dollar, I think it is, per linear foot, is it not?

A Yes.

Q And it ends up at being close to $2.50 per linear foot in the 2003 to 2006 period?

A That is correct.

Q Would you accept subject to check that that is an annual escalation rate during that period of about 8.7 percent?

A Yeah, subject to check.

Q And then on page 115, line 5, you have reference to the increasing removal cost per unit. Do you see that?

A Yes, I see that.

Q And that is followed by Table Roman 5-48 showing in more detail what has happened since 2000 through 2006, again, with four-year rolling bands?

A Yes, that is correct.

Q Would you accept subject to check that the increase from a $1.86 per unit on the first line to $2.52 on the last line for the removal cost per unit reflects an annual increase of approximately 10.6 percent per year?

A Yes, subject to check.

Q So, Mr. Fisher, what is your understanding of what has caused Edison's cost of removal for this account to go up by 9 percent in the period covered by Figure Roman 5-10 or 10.6 percent in the period covered by Table Roman 5-48?

A Well, certainly part of it is cost escalation. But I believe that question is probably better served to the T&D capital witness. Those are capital costs that our business units incur.

Q But the cost escalation ought to be basically a labor cost escalation; is that correct?

A Yeah. But that would only make up part of this. There may be other circumstances that can contribute to this annual increase.

Q So what effort did you make in putting together the study to understand what was causing this change in the costs over that period of time?

A We didn't analyze this specifically. What we do is -- depreciation study takes about a year and a half to two years to conduct. We start with interviewing the field personnel, and understanding the operations of what has changed over the last 15 years and what may change going forward.

So if they don't say anything has changed significantly, or that they don't expect any changes from our current operations going forward, then we don't necessarily go into the details of understanding it. Because there is little need to make adjustments to the data to reflect those changes.

Q Okay. Let me get you to turn to what has been marked as TURN-44. And with the -- TURN would gladly stipulate that we need to work on our Excel skills.

But with that understanding, would you be -- looking at the first page after the cover page, do you see that testimony, this as data from Account 365.

A Yes, that is what it says.

Q And do you see that table across the top of the page shows cost of removal figures from your workpapers?

A I'm sorry, can you say that again?

Q Sure. Let me try it this way: The first column is cost of removal in nominal dollars. Do you see that?

A Yes.

Q And those are figures that Edison reported in its workpapers; is that correct?

A Subject to check, I believe.

Q I'm sorry, I'm not --

A I'm sorry. We do provide these numbers. I haven't verified that these are the numbers that we provided.

Q Thank you. That was the question I was trying to form.

In your workpapers Edison also reported an escalation factor for each of the years; is that correct?

A That is correct.

Q Would you accept subject to check that the figures in Column B reflect the ones Edison used for this account?

A Yes. I have to note that we calculated all these as part of our analysis. There may be some rounding differences as to why you may see some bottom line difference at the bottom there.

So these are the numbers -- I'll accept subject to check these are the numbers reported in our workpapers. They may not have been the actual rates that we did our calculations, because there may have been additional decimal places.

Q And by the same token -- well, sorry, let me move on.

The third column where it says COR in 2006 dollars, do you see that?

A Yes.

Q Would you accept, again, subject to check, that this is the nominal cost removal times of the escalation factor for each year?

A Yes, I will accept that subject to check.

Q And then in a data request response Edison provided the number of units retired per year for this account; is that correct?

A That is correct.

Q And that is the information that is in Column D? I'm sorry, would you accept subject to check that that is the information in Column D?

A I will accept subject to check.

Q And based on that you can calculate a unit cost removal both in nominal terms and in terms of 2006 dollars; is that correct?

A Yes, that is correct.

Q Let me get you to turn the page -- to the chart that follows. Do you see that?

A Yes.

Q Would you agree that the lower of the two lines on this chart replicates the line shown on page 114 of SCE-11C? In other words, it starts to about 1 and climbs to about $2.50 during the last period?

A Yes.

Q And would you accept subject to check the line above that reflects the 2006 dollar values for that account?

A It looks like it reflects an averaging, a rolling average. Yeah, it says that at the top, Four-Year Rolling Average.

Q Is it correct that if Edison's cost for this account were escalating in the 1992 to 2006 period at the same rate, that was the Handy-Whitman escalation factor for those years, that the 2006 dollars line you could expect to be about a straight horizontal line?

A If the cost escalation was restricted purely to inflation or the cost escalation factor you are referring to, that would be the case.

Q So does this indicate that the cost per unit for Edison for Account 365 went up faster than the rate of escalation that is reported by Handy-Whitman?

A I can't tell from here whether it went up faster or not.

Q Didn't you -- wasn't your prior answer if it went up at the same rate it would be something close to a horizontal line?

A I'm sorry. Maybe I misunderstood the question. So the total, I would agree that the total cost escalation went up faster than the Handy-Whitman Index. Maybe I misheard the question.

Q Let me get you to turn to the excerpt of workpapers that I've handed out. And I apologize to everyone, working off the excerpt I managed to copy it in a way that is difficult to see the page numbers. But, again, the last two pages, would you accept that these are pages 98 and 99 out of your workpapers?

A I'll accept that subject to check.

Q Looking at page 99, the last page of this excerpt, in the second-to-the-right-hand column, Analyzed Escalation Rate, do you see that?

A I do see that.

Q Is that figure intended to represent the annual rate necessary to get you to the escalation factor for that year starting at an escalation factor of 1.5 in 2006?

A Well, it is intended to reflect what that is. We actually derived it using the escalation factor. So we didn't use the rate to derive the escalation factor, we used the escalation factor to derive the rate.

Q Okay. That is simply because Handy-Whitman provides escalation factors, not rates?

A That is correct.

Q So looking at the line for 1992, the

annualized escalation rate reported there is 4.4 percent?

A Yes.

Q So if I understand this correctly, if you escalated on an annual basis at a rate of 4.4 percent, you would get from -- actually, I guess you would be de-escalating. If you de-escalate it at the rate of 4.4 percent from 1992 to 2006, you would get from 1.84 down to 1.0 during that period?]

A I'm sorry, I --

Q Yeah, that was not --

A Could you repeat that or maybe rephrase it?

Q Let me try to do it the other way.

Is it correct that to get from the 1.0 figure in 2006 to the 1.84 figure -- I'm sorry -- yeah, the 1.84 figure for 1992, you would need to escalate at an annualized rate of 4.4 percent over that period?

A I don't think you would escalate 2006 costs in 1992 costs.

Maybe I can rephrase my answer to help fit with what maybe you're trying to ask. And that's, to get from 1992 dollars to 2006 dollars, you would escalate it by the 4.4 percent annually. I hope that --

Q That was so much more straightforward a statement of it than I was ever going to put in a question. Thank you.

Turning back to what's been marked as TURN 44, the third page back is a data table for Account 354.

And that account is for transmission towers; is that correct?

A Yes, 354 is for transmission towers.

Q And then turning to the chart that follows it, do you see that on a rolling four-year average the nominal value starts at about 2,500 in the '92-to-'95 time frame and ends up something over $20,000 in the '03-to'06 time frame?

A I'm going to assume that this, since it doesn't have a heading on it, that it's also a four-year rolling average?

Q It is. The -- yes.

A If it is the case, then, yes, that's what it shows.

Q And let me get you to accept subject to check, if you would, Mr. Fisher, that all of the charts in here show four-year rolling average figures?

A Yes, I will accept that subject to check.

Q Reasonably sure none of them other than the first one have that label.

Would you also accept subject to check that the increase from about 2,500 to something over 20,000 during that period is an annual increase of approximately 20 percent per year?

A Yes, I will accept that subject to check.

Q Let me get you to turn, if I could, Mr. Fisher, three accounts back. It's Account 358. So it's about halfway through the document, and it's in the upper left-hand corner that it says Account 358.

A Yes, I see that.

Q And do you see in the column marked "Response DR TURN 40-01" --

A Yes.

Q -- there's a figure that's bolded and underlined?

A Yes, I see that.

Q How is it that there are only 121 units retired in a single year?

A Well, this is transmission underground conductors. So typically, we're not removing transmission underground conductor unless circumstances deem it. So that's one reason why we could see anomalies like that.

The other reason is due to accounting issues and timing lag on when construction may occur and the actual work order actually gets recorded. So in this case, we could -- the costs could have been -- or I mean the costs and retirement units could have been recorded in 1996 for additional work orders and not reflected in 1995.

That's one of the primary reasons we evaluate averages and the entire 15-year history to kind of smooth those things out.

Q Okay. Mr. Fisher, just to possibly speed things up a bit, would you be willing to accept subject to check that the representations in these tables and charts in TURN-44 accurately reflect the figures Edison reported for Accounts 354, 355, 356, 358, 364 and 365?

A When you say accurately reflect the figures, what figures are you referring to in my testimony workpapers?

Q Well, the figures reported in the table as coming from Edison workpapers or Edison's data request response.

A Yes, I'll accept that subject to check.

Q Let me get you to turn back to the excerpt of the workpapers for account -- the last five -- I'm sorry, the last four pages are -- the last four pages are all from Account 365; do you see that?

A Yes, I see that.

Q Turning to page 97; do you see that?

A Yes, I do.

Q And this is the data that Edison used or at least part of the data Edison used to derive its proposed cost-of-removal factor and net salvage factor?

A That is correct.

Q And to the extent these recorded amounts reflect inflation that occurred during the 1992-through-2006 period, does applying those factors going forward in effect assume approximately the same inflation going forward?

A Not necessarily. It really depends on what our proposal is.

Q Well, if your proposal is basically to use something very close to the net salvage percentage that comes out of this net salvage analysis on page 97, wouldn't that be true?

A Yes. There is embedded escalation differences between the retirement unit dollars -- the retirement dollars and the costs-for-removal dollars. So to that extent, there is inflation embedded in those ratios.

I'd like to point out, though, that the inflation isn't necessarily from 1992 to 2006. It's going to be a reflection of the age of the retirement. So the period could be much longer as well.

Q What you are describing is an escalation based on comparing the historical investment costs to the recorded costs of removal; is that correct?

A Yes, that is correct.

Q But looking just at the costs of removal per unit on a year-to-year basis, isn't there also escalation reflected there?

A Are you referring to the costs of removal per unit on this -- this workpaper?

Q We could certainly start with that, but the recorded costs of removal for any given year would reflect a certain amount of escalation when you calculate the costs of removal per unit?

A I'm not completely understanding because the cost of removal per unit is the cost in that year. So you need a relative basis to apply or compare whether or not there's escalation relative to -- to what.

Q Well, looking at page 97 side by side with page 114 of the depreciation study, SCE-11C, I think you accepted subject to check that the cost of removal per unit reflected on figure Roman 5-10 reflects an annual escalation rate of approximately 8.7 percent; is that correct?

A Yes.

Q And wouldn't the same cost-of-removal data that's reflected on this figure be cost-of-removal data embedded in these figures on page 97?

A I think what I'm getting hung up on is cost of removal embedded in these figures. Maybe I can rephrase a response that would satisfy your question.

The cost-of-removal figures on that page 97 reflect inflation from year to year in comparing the year-to-year cost of removal. I was getting hung up on do these figures include inflation.

Q Okay. Thank you.

Let me get you to turn to what's been marked as TURN-45. Do you recognize this as an excerpt from the book *Depreciation Systems* by Wolf & Fitch?

A I do.

Q And this time I think it was Edison's fault, Mr. Fisher, but there's no page numbers after the first page. But if you turn to the second page of text here on the left-hand side, I believe that's page 262 of the text?

A It appears so.

Q And about midway down the page, there's a paragraph that starts, "Before attempting to forecast"; do you see that?

A Yes.

Q And it makes reference, again about midway through the paragraph, about how the cost of retiring a unit can be independent of the age of the unit; do you see that?

A Yes, I see that.

Q And do you have any disagreement with that statement?

A No, I do not.

Q Mr. Fisher, if I could get you to turn back to the excerpt from your workpapers. Again, page 97, the net salvage analysis data. Beneath -- well, do you see the line that's on the left-hand side labeled 15-year average with no inflation?

A I do.

Q And this line uses all 15 years of the data that had been reported in the upper part of that table; is that correct?

A That is correct.

Q And it results -- the calculation of the 15-year average with no inflation results in a net salvage percent of negative 28 percent; do you see that?

A Yeah. I just want to point out that the no inflation means there is no inflation parity between the retirements and costs removal. So all those dollars were brought up to 2006 dollars; but, yes, the ratio is minus 28 percent.

Q And they were brought up to 2006 dollars again using the Handy-Whitman Index?

A That is correct.

Q So is the negative 28 percent the net present value of the negative 121 percent that Edison calculated above as the 1992-to-2006 figure?

A I'm just hesitating because of the term "net present value." I would say it's the 2000 -- it's the value in 2006 dollars.

Q It's -- it's --

A I'm sorry, the ratio does not include inflation. So yes, I'd agree with that statement.

Q And the rest of your workpapers have similar calculations for, I think, all of the other transmission and distribution accounts, that is, a calculation showing the 15-year average with no inflation?

A Yes.

I'd like to point out, if I could --

MR. FINKELSTEIN: I'm sorry, your Honor, there's no question pending.

MR. MC NULTY: Well, your Honor, he should be allowed to clarify the answer. He gave a direct response. Sometimes questions start out the answers with a simple "yes" or "no."

MR. FINKELSTEIN: But for the long pause between the answer and the follow-on, you know, I might be more amenable to that explanation, but this seems like it's coming out of the blue.

MR. MC NULTY: I don't know what the pause has to do with anything, your Honor. Mr. Fisher needs a chance to think about the response before he gives it. He gave a direct response saying no, and he wants now to clarify that response.

ALJ DE ANGELIS: Okay. You can go ahead and clarify your response.

THE WITNESS: Yeah, I was just mulling over still that net present value classification. And the reason I was hesitating is because that negative 28 percent really reflects a cost-of-removal percentage of plant in the plant dollars whenever they're recorded. So I just wanted to clarify more about phrasing that as a net present value.

MR. FINKELSTEIN: Q Yeah, but it is an inflation-adjusted value. The negative 28 percent is a value derived by removing inflation from the negative 121 percent calculated as a 1992-to-2006 figure?

A Yes. If I can say it in other words, that is a percent it would cost to retire an asset of its original installation in the year that asset is installed.

MR. FINKELSTEIN: Okay. Thank you.

Your Honor, could we take a short break just in the hope that I can pare down some of my remaining questions?

ALJ DE ANGELIS: Sure.

MR. FINKELSTEIN: Perhaps ten minutes.

ALJ DE ANGELIS: Ten minutes?

Why don't we come back at 20 after.

(Recess taken)

ALJ DE ANGELIS: On the record.

MR. FINKELSTEIN: Q Mr. Fisher, we discussed earlier how for some portion of Edison's recorded cost of removal comes from an allocation of the total costs of plant replacement; do you remember those questions earlier?

A Yes.

Q And just so it's clear, this occurs, say, if there's a pole that needs replacement in the field, Edison goes out, digs up the old pole, installs the new pole, fixes up the site and leaves and incurs total costs for that job; is that correct?

A That would be a general way of saying it, and in most cases that's true.

Q And then some portion of that total cost is allocated to the cost of removal, and the remainder is allocated to plant in service?

A When you say "allocated," what -- what do you mean?

Q Well, for Edison's plant records, some of the cost is recorded as cost of removal and some of the cost is recorded as plant in service?

A That is true.

Q So all else equal, would recording a greater portion of the total project cost to cost of removal and a corresponding lesser amount to plant in service cause an increase in the recorded cost-of-removal percentage?

A All else being equal, yes.

Q Let me get you to turn to what's been marked as TURN 46. These are the Edison annual depreciation reports. Do you see that?

A Yes.

Q And this first one with a date of May 1st is indicate -- I'm sorry -- is intended to report to the Commission Edison's recorded gross plant in each of its accounts as of January 1, 2008; is that correct?

A I'm sorry, what was your question: Is that the intent of the report, or does the report do that?

Q I'm sorry, does the report do that? Is that one of the things the report does?

A Yes.

Q So it updates the gross plant.

Is there any change made to the estimated future net salvage percent?

A No.

Q I'm sorry, let me be clear with the question, Mr. Fisher.

Assuming the Commission has not authorized a change, does it use whatever was the last approved net salvage percentage?

A Yes.

Q And then the report applies that percentage to the updated gross plant?

A That is correct.

Q So then you are calculating a new net salvage amount but using the existing rate applied to a new gross plant number?

A Yes, in this report.

Q And this is something that Edison files every year with the Energy Division?

A Yes, it is.

Q And so for the first one, this one that's dated May 1, 2008, is it intended to capture the state of things as of January 1, 2008?

A The purpose of the report is to show the depreciation rates that we intend to use for the year. And so it states everything as of beginning of year 2008.

Hopefully, that answers your question.

Q So when you say the depreciation rates that you're going to use, is the depreciation rate going to be what comes out of this Column 12 on the table -- the first page of the table for the May 1, 2008 report?

A Yes, and those rates are equal to the current authorized rates at that time.

Q So other than the gross plant figure for January 1, 2008 and --

A I have to -- I'm sorry. I have to point out that that wasn't entirely correct, my last answer.

For T&D accounts, those are the rates.

For generation accounts, we don't use a rate times plant. So I didn't want that to apply to all the -- the accounts displayed on this report.

Q And would you accept subject to check that the three reports that are included in TURN-46 represent the three most recently filed reports from Edison to the Energy Division?

A Yes, I'll accept that subject to check.

Q Let me get you to turn in your testimony to page 36. I'm sorry, it's the depreciation study, SCE-11C, page 36.

A Yes, I'm there.

Q And starting on line 12, there's a discussion about through-boring, t-h-r-o-u-g-h, hyphen, b-o-r-i-n-g; do you see that?

A Yes, I do.

Q And lines 16, 17, you state that the last three years of additions comprise about 20 percent of the current investment?

A Yes.

MR. FINKELSTEIN: Your Honor, I apologize. I did not include this page in the excerpt that was circulated, so I'm not sure -- I'm hoping this won't present a problem; but I'm going to need to have a reference to the workpapers made.

Q Mr. Fisher, in the workpapers for the net salvage part of the depreciation study, can I get you to turn to -- I believe it's page 89. I'm sorry, page 91. And do you see the column entitled, "Recorded Additions"?

A Yes.

Q Would you accept subject to check that the additions reported here for 2004 through 2006 total approximately $274 million?

A Yeah, I'll accept that subject to check.

Q And turning back to page 88 of the workpapers, Item E on this page shows a year-end 2006 plant balance of 1.9 -- I'm sorry -- $1.09 billion; is that correct?

A That is correct.

Q Would you accept subject to check that 274 million is approximately 25 percent of 1.09 billion?

A Yes, I'll accept that subject to check.

Q And then looking back at what's been marked as TURN-46, the depreciation report, for the report filed May 1, 2008, the last page of tables shows for account -- I'm sorry.

ALJ DE ANGELIS: Would you give us a reference of some sort to make sure we are all on the same page?

MR. FINKELSTEIN: Yes.

Q I'm sorry, you see the May 1st, 2008 letter?]

A Yes.

Q And then two pages back from that is a table where the top of the left hand column it says distribution plant.

A Yes.

Q Do you see there reports for Account 364, I think it's line 25, for gross plant, it reports approximately 1.173 billion?

A Yes, I see that.

Q And would you agree that that suggests that there were additions of approximately $83 million in 2007 to this account; in other words, the difference between 1.173 billion and 1.09 billion?

A I'll qualify my answer that those are net additions, additions less retirements that occurred during the year.

Q So actually the additions are likely a greater amount than that?

A Likely, yes.

Q Let me get you to turn to what's been marked as TURN-47, which are some responses to data requests. And the first part of that, the first two pages are an Edison document regarding through-boring treatment of its poles. Do you see that?

A Yes, I do.

Q And turning to page 2, just above the pictures, after the word Benefit, this document describes how through-boring will prolong the average in-service life by 20 years over conventional treating methods.

A Yes, I see that.

Q And is it correct that as of 2004, Edison was installing only through-bored poles for its distribution poles? I'm sorry, for its wooden distribution poles?

A That's what I understand from our operations folks, yes.

Q And the same is true for wooden transmission poles, since 2004, it's been only through-bored poles?

A Again, it's what I understand from our operations folks, yes.

Q Let me get you to turn back to the excerpt from your workpapers. And after the cover page, there are several tables that I believe were -- sorry, pages 4 through 6 of your workpapers. Do you see those?

A Yes, I see those.

Q Let me get you to turn to the third page of table -- and at the upper left hand it should say Steam Production -- Solar 2 Decommissioning?

A Yes, I see that.

Q And about halfway down the page there's a line for Account 364 poles. Do you see that?

A Yes, I do.

Q And in the column, you see the column marked REM life? It's column 10.

A Yes, I do.

Q And that's an abbreviation for remaining life?

A That is correct.

Q So the remaining life of this plant is -- I'm sorry. The remaining life for this account, Account 364 is 36.9 years in Edison's study?

A Yeah. To be a little more specific, that's the average remaining life for the mass asset. So some are expected to retire sooner and some are expected to retire later.

Q And then the next column over is Annual Accrual. Do you see that?

A Yes, I do.

Q And is it correct that the annual accrual is calculated by dividing the figure in column 5, the Depreciable Balance, by the average Remaining Life in column 10?

A That is correct.

Q So for here, you've calculated for Account 364 an annual accrual of approximately $94.5 million using the 36.9 year average remaining life?

A Yes. And the end of year '07 -- rather, end of year '06 plant and accumulated depreciation was zero balances.

Q Right. Which is consistent with the heading for column 1, this is Gross Plant as of January 1st, 2007?

A Yes.

Q Would you accept subject to check that if you increase the average remaining life by five years for Account 364, the resulting annual accrual would be reduced by approximately $11.3 million?

A I'll accept that subject to check.

Q Let me get you to turn in your depreciation study SCE-11C to page 54. It's actually starting on 54, then carries over to 55. It's your discussion of the estimated life for the Mountainview plant; is that correct?

A Yes.

Q And the sentence that carries over says that Edison's experience with coal generation is a reasonable proxy for the Mountainview plant; is that correct?

A Yes.

Q But Mountainview is a gas-fired plant, is it not?

A That's correct.

Q And at the site of a former gas plant?

A That's my understanding, yes.

Q Okay. And Edison has had a long history owning and operating gas-fired generation plants; is that correct?

A That's my understanding, yes.

Q Are you familiar at all with the life span that Edison experienced with its gas-fired generation plants in the past?

A No, I am not.

Q So in preparing your depreciation study, did you look at all to Edison's experience with gas-fired plants?

A No.

Q How did you come to the conclusion that the experience with coal generation would be a reasonable proxy?

A Well, similar to what I said earlier, we started the depreciation study right off the bat with discussing the assets with the operation folks. And so I discussed this with our power production business unit and what their expectation was given this gas plant, which I believe is a combined cycle gas generation unit, and got their opinions and how they felt the life would be. And it was also what we had in the current PPA for Mountainview as the life span for the plant.

Q And PPA stands for purchased power agreement?

A That is correct.

Q And the purchased power agreement was a negotiated document between -- I'm sorry. What are the parties -- to your knowledge, who are the parties to that purchased power agreement?

A I have to be honest. I don't know much about the purchased power agreement, but my understanding is it's with SCE and FERC or a subdivision of SCE. I'm really not familiar.

Q In your depreciation, SCE-11C page 23 to -- yeah, I'm sorry, page 23 -- you discuss the amortization period of the remaining investment in the meters that are getting replaced by Edison's smart meters. Do you see that?

A Yes, I do.

ALJ DE ANGELIS: Could you give me a line citation, please.

MR. FINKELSTEIN: I'm sorry. It's starting on line 14 of this page.

ALJ DE ANGELIS: Thank you.

MR. FINKELSTEIN: Q As I understand your testimony, Edison expects to have all of the existing meters replaced by the end of 2012; is that correct?

A Yes. I wouldn't necessarily say all of them, but nearly all of them will be replaced by 2012.

Q And your proposed amortization period would collect the remaining net investment in those replaced meters through 2026; is that correct?

A In addition to the cost incurred to retire those units, yes.

Q Well, would the remaining net investment in those replaced meters be included in rate base?

A Yes.

Q So would Edison be continuing to collect a rate of return on the net investment in the replaced meters?

A Yes, we would.

Q Would the cost of removal that you just referred to in an earlier answer be included in rate base?

A To the extent that the cost of removal is incurred and not yet recovered, it would, yes.

Q So Edison be also earning its authorized rate of return on that portion of the cost of removal that was incurred and not yet recovered in rates?

A Yes.

Q Is it your understanding that -- are you familiar at all with the term used and useful in providing utility service?

A I am.

Q And is it your understanding that a plant needs to be used and useful in providing utility service in order to be in rate base?

A That's typically one of the conditions, yes.

Q So how would the meters that have been removed and replaced be used and useful in providing utility service after their removal?

A Well, it wouldn't be used and useful. But typically, the shareholders are allowed to recover their cost in investment in capital. This was in lieu of -- this proposal was in lieu of proposing an -- the proper way of depreciating this would be to shorten the remaining life over the period there we were going to replace it.

So we felt that in lieu of doing that which would exacerbate costs during that period was to propose an amortization over the remaining life. In doing so, yes, it would create some rate base impacts over the remaining life.

MR. FINKELSTEIN: Your Honor, could I have a second off the record?

ALJ DE ANGELIS: Off the record, please.

(Off the record)

ALJ DE ANGELIS: Back on the record.

MR. FINKELSTEIN: That's all I have, Mr. Fisher. Thank you very much.

Thank you, your Honor.

THE WITNESS: Thank you.

ALJ DE ANGELIS: Mr. Finkelstein, I have one question for you.

When you referred to the used and useful issue in your last question --

MR. FINKELSTEIN: Yes.

ALJ DE ANGELIS: -- you addressed that issue in your testimony; is that correct?

MR. FINKELSTEIN: I believe I did, your Honor.

ALJ DE ANGELIS: Okay. And I guess my question is, is that the only place in TURN's testimony where the issue is addressed?

And if you can't answer that now, that's fine. I was just trying to figure out exactly where the issue was in the testimony. And I only saw a reference in your testimony.

MR. FINKELSTEIN: It only seems fair, your Honor, to accept that subject to check.

ALJ DE ANGELIS: Okay.

MR. FINKELSTEIN: I think that is true, but I can confirm that.

ALJ DE ANGELIS: Okay. Any redirect?

MR. MC NULTY: Yes, your Honor. Just a few.

ALJ DE ANGELIS: Okay.

REDIRECT EXAMINATION

BY MR. MC NULTY:

Q Mr. Fisher, directing you first to Exhibit 11, SCE-11C, the depreciation study at page 70.

A Yes, I'm there.

Q Mr. Finkelstein asked you some questions about the statement on line 1 that removal cost is mostly labor and also asked you some cross referencing questions about the Handy-Whitman index. Do you recall those?

A I do recall that.

Q First, why did you use the Handy-Whitman index?

A It's an easily accessible index for us. We typically use it for our plant accounting data and capital costs related to accounts.

Q In your addressing on this line 1 removal -- you state removal cost is mostly labor. What about the construction cost. Is that mostly labor also or not?

A From my experience in talking with the operation personnel, typically labor is a large component of installation cost as well.

Q You were asked some questions by Mr. Finkelstein regarding Exhibit TURN-47, the through-boring process. Do you recall those?

A I do recall those.

Q Is the deterioration of the wooden poles, is that the only factor that affects the life of the pole?

A No, it's not. It makes -- just roughly over 50 percent of it for distribution poles is deterioration, but there's many other factors that affect retirements of those poles.

Q Lastly, you were asked several questions about the excerpt of workpapers.

I can't recall the exhibit number, if this was given one, your Honor.

ALJ DE ANGELIS: It was not.

MR. MC NULTY: But this was three pages --

Thank you, your Honor.

Q Three pages into this excerpt, you were asked a series of questions about Account 364. Do you recall that?

A I do.

Q And looking at the column -- you were asked by Mr. Finkelstein some questions regarding the column Remaining Life being 36.9. Do you see that?

A Yes.

Q Also on this same line for Account 364, there's a figure that says R0.5 and there's a column that says Average Service Life of 45. What is the overall life span for this account?

A Well, the R0.5 refers to a retirement dispersion curve. So that's a frequency of retirements over the life of the plant. The 45 merely refers to the average service life. But in my testimony, I actually specify some of the statistics related to that.

Q Did you provide a reference that you're referring to?

A Yes. Give me one second.

It's on Exhibit SCE-11C, page 36. And it's the last sentence in the first paragraph, starts the R0.5 curve, 45-year curve-life retirement characteristics are reasonably conservative, specifying that half of the retirements will occur between the ages of 25 and 64 years old with the highest level -- and that's the mode on the retirement frequency curve -- at age 43 of the assets.

It also indicates that 25 percent of the retired poles will occur over a period of age 65 through the age 90.

So that means the last unit following this retirement dispersion will retire after 90 years of age.

Q In your last response I think you said 43. But looking at your testimony at line 9, it says 53. Did you misspeak?

A I must have, yes.

MR. MC NULTY: Thank you.

No further questions, your Honor.

EXAMINATION

BY ALJ DE ANGELIS:

Q Could you clarify for me whether the amortization period for the replaced meters as a result of Smart Connect, was that method approved in another Commission proceeding?

A The method of amortizing those costs over the remaining life, no.

We didn't realize this, the situation until recently between the '06 GRC -- our '06 GRC and our current proceeding.

Normally, using group depreciation, when you retire an asset, you assume it's fully depreciated. And meters follow group depreciation.

In case of Edison Smart Connect, replacing almost all of our current existing meters, we felt that we should bring that to light.

And typically, we would reduce the life to reflect that anticipation change in operations. Instead, we proposed that we amortize it over 20 years as a way to mitigate rates.

ALJ DE ANGELIS: Okay, thank you.

MR. FINKELSTEIN: Your Honor, if I could have a follow-up question.

ALJ DE ANGELIS: Okay.

RECROSS-EXAMINATION

BY MR. FINKELSTEIN:

Q Mr. Fisher, in the depreciation study, SCE-11C, page 36, in the discussion about the curves for Account 364, the first line refers to an estimate you received from SCE engineers about the average life of existing poles.

Is it correct that virtually -- I'm sorry --

the vast majority of those existing poles would have been poles that had not had the through-boring treatment?

A That is correct.

Q And when the engineers reported the average age of the poles retired, that again would not have reflected poles that had had the through-boring treatment?

A We haven't done that analysis, but that would be a reasonable assumption.

MR. FINKELSTEIN: Okay. Thank you again.

MR. MC NULTY: Nothing further, your Honor.

ALJ DE ANGELIS: All right. Thank you.

THE WITNESS: Thank you.

ALJ DE ANGELIS: You're excused.

Off the record.

(Off the record)

ALJ DE ANGELIS: On the record.

Would DRA like to call its next witness?

MS. SALVACION: Yes. DRA calls witness Bernard Ayanruoh.

ALJ DE ANGELIS: Thank you.

May I swear you in?

MR. AYANRUOH: Yes.

BERNARD AYANRUOH, called as a witness by Division of Ratepayer Advocates, having been sworn, testified as follows:

ALJ DE ANGELIS: Thank you.

Please be seated, and state your name and business address for the record.

THE WITNESS: My name is Bernard Ayanruoh, spelled B-e-r-n-a-r-d, A-y-a-n-r-u-o-h. My business address is 505 Van Ness Avenue, San Francisco, 94102.

ALJ DE ANGELIS: We have TURN and Edison; is that correct?

MR. MC NULTY: Yes, your Honor.

ALJ DE ANGELIS: All right. And before we start, I just want to remind parties as I have done before to please question within the scope of the proceeding, and to avoid duplication, and to raise matters in briefs rather than in cross when appropriate.

TURN.

MR. FINKELSTEIN: Thank you, your Honor.

TURN had distributed in the hearing room a cross-examination exhibit that we'd like to get marked next in order which I believe would be TURN 48.

ALJ DE ANGELIS: Okay. And that is --

MR. FINKELSTEIN: That is Responses to Data Request TURN-DRA-001 Regarding Depreciation Testimony of Bernard Ayanruoh.

ALJ DE ANGELIS: Okay, we'll mark that for identification as TURN-48.

(Exhibit No. TURN-48 was marked for identification.)

MR. FINKELSTEIN: Thank you.

CROSS-EXAMINATION

BY MR. FINKELSTEIN:

Q Good afternoon, Mr. Ayanruoh.

A Good afternoon.

Q Do you have before you a copy of what's been marked as TURN-48?

A Yes, I do.

Q If I asked you these questions today, would you give me the same responses?

A Yes, I would.

MR. FINKELSTEIN: Your Honor, I've got nothing further for this witness.

ALJ DE ANGELIS: Okay, thank you.

Mr. McNulty.

MR. MC NULTY: Thank you, your Honor.

And we do have a couple of exhibits that I believe have been handed out.

And while I am mindful of your admonition to avoid duplication, I must confess we did not coordinate our cross-examination with TURN for reasons I hope are obvious. So there may be some duplication in terms of these exhibits that we are asking for identification.

We have for Mr. Ayanruoh a copy of some of our workpapers, for example.

ALJ DE ANGELIS: Okay.

MR. MC NULTY: So first, we'd like to have marked for identification a document called Excerpts from SCE-11, Volumes 2 & 3, Workpapers.

We had marked that as SCE-50 in the upper left-hand corner, but we ask that that actually be marked for the record.

ALJ DE ANGELIS: All right, we'll mark for identification as SCE-50.

(Exhibit No. SCE-50 was marked for identification.)

MR. MC NULTY: I went in reverse order. There's another document that's labeled DRA's Responses to SCE-DRA-059. And appended to these responses was actually part of the question we asked DRA were excerpts from Mr. Fisher's workpapers. We ask that that be marked as Exhibit SCE-49.

ALJ DE ANGELIS: Okay, that will be marked for identification as SCE-49.

(Exhibit No. SCE-49 was marked for identification.)

MR. MC NULTY: And last, your Honor, although there's no need to make this an exhibit, I have provided to DRA's counsel a cover page of the Commission's decision in Edison's 2006 rate case and two pages dealing with depreciation topics from that decision. I'm just going to refer Mr. Ayanruoh to those two pages. And for his convenience, I've provided these excerpts.]

ALJ DE ANGELIS: Okay. And I have one more -- I have SCE-51.

MR. MC NULTY: SCE-51, your Honor, is the subject I mentioned earlier which deals with the text on page

185, the rate case decision on retirement severance. We are providing a printout for the parties in the hearing room today, we also served that electronically. But it doesn't affect Mr. Ayanruoh.

ALJ DE ANGELIS: Okay. That is marked for identification as SCE-51.

(Exhibit No. SCE-51 was marked for identification.)

MS. SALVACION: Your Honor, if we can also mark DRA's exhibits?

ALJ DE ANGELIS: Yes.

MS. SALVACION: We have DRA-18, which is depreciation expenses and reserves. And DRA-20, which is post-test year ratemaking.

ALJ DE ANGELIS: All right.

(Exhibit Nos. DRA-18 and DRA-20 were marked for identification.)

ALJ DE ANGELIS: Mr. McNulty.

MS. SALVACION: Your Honor, I believe we need to go through the direct examination first.

MR. FINKELSTEIN: TURN kind of jumped the gun with its cross. My fault.

ALJ DE ANGELIS: Go ahead.

DIRECT EXAMINATION

BY MS. SALVACION:

Q Mr. Ayanruoh, do you see before you what is marked as DRA Exhibits 18 and 20?

A Yes, I do.

Q Did you prepare these exhibits and adopt them as your direct testimony?

A Yes, I do.

Q And are your qualifications contained on page 1 of Exhibit DRA-23, labeled Qualifications of Witnesses for Southern California Edison Company, General Rate Case, Test Year 2009?

A Yes.

Q And do you have any additions or corrections to make to either your testimony in DRA Exhibits 18 or 20?

A No.

Q Are the facts and opinions set forth in these exhibits true and correct to your knowledge?

A Yes, they are.

MS. SALVACION: We have no further direct. The witness is available for cross-examination.

ALJ DE ANGELIS: Thank you.

MR. MC NULTY: Thank you, your Honor.

ALJ DE ANGELIS: Can we go off the record for a moment.

(Off the record)

ALJ DE ANGELIS: Back on the record.

MR. MC NULTY: Thank you, your Honor.

CROSS-EXAMINATION

BY MR. MC NULTY:

Q Good afternoon, Mr. Ayanruoh.

A Good afternoon.

Q We just have a few questions for you on depreciation, nothing on post-test year ratemaking testimony.
A Okay.
Q Just for background, you were also DRA's witness on depreciation issues in Edison's 2003 general rate case?
A That is correct.
Q And also same depreciation witness for DRA in Edison's 2006 general rate case?
A That is correct.
Q Can I refer you to your testimony in DRA-18, page 17. Do you have that in front of you?
A Yes, I have it.
Q Is it correct that you are asking the Commission to require Edison to establish a regulatory liability similar to that established for PG&E in its 2007 rate case?
A That is correct.
Q But is it your understanding in general that a regulatory liability, the one that you are recommending here, would be for accumulated cost of the removal that has not yet been spent?
A That is correct.
Q Were you aware that in the 2006 general rate case decision the Commission directed SCE to establish a regulatory liability for its accumulated cost of removal not yet spent?

A Well, my reading of that decision is that it was acknowledged in the decision, but it was not formally ordered.

Q Well, you have in front of you the excerpts that we gave you from the 2006 rate case decision.

A Yes, I do.

Q Could you look in those excerpts. And for the record, I'm referring to Decision 06-05-016.

Could you look in that excerpt at page 204?

A Yes.

Q Do you see that statement, first sentence under the heading number 16.7.1, where it says: TURN requests that the balance of funds collected for cost of removal related to non-ARO assets be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted.

Does that refresh your recollection regarding the Commission's decision in 2006?

A Yes, it does.

Q You are not proposing anything different in your testimony than what the Commission directed in 2006 regarding this specific issue?

A That is nothing different.

Q I would like to direct you to the next page of your testimony in Exhibit DRA-18. This is at page 18. We have several bullet items on that page.

A Yes.

Q And you also state on that page that:

Consistent with the Commission's decision in the PG&E 2007 rate case that Edison provide what you've characterized as the then current balance of prefunded removal cost; is that right?

A That is correct.

Q What I'm referring to is the second bullet -- excuse me, the first bullet on that page, the one that is on line 4.

ALJ DE ANGELIS: Off the record.

(Off the record)

ALJ DE ANGELIS: Back on the record.

MR. MC NULTY: Thank you.

Q I'm sorry, Mr. Ayanruoh, if we could repeat that.

Looking at line 4 of page 18 of DRA-18, I was directing you to that recommendation that Edison be directed to provide the then current balance of prefunded removal costs. Do you see that?

A I do.

Q Did you -- I assume you did review Edison's testimony and workpapers on depreciation as part of your responsibility?

A Yes.

Q Are you aware that Edison did provide the accumulated balance on the cost of removal not yet spent?

A Yes, I did, in a data response to one of my questions.

Q Let's look again on page 18 of your testimony, lines 6 through 8 on this page. The second bullet item on this page has two separate recommendations. Do you see that?

A I do.

Q You also request on the first part of that second bullet that Edison provide a year-by-year projection of when the then existing balance of prefunded removal costs will be consumed; is that correct?

A That is correct.

Q Did you provide any examples, calculations or explanation of how Edison was supposed to determine that amount?

A No, I did not.

Q Do you have any recommendations today on how that calculation should be performed?

A I honestly have not thought about that, how that should -- this is more or less a current recommendation that has been applied to other utilities. And I am assuming that Edison knows what this entails.

Q You know Mr. Fisher sitting next to me on my right?

A Yes, I do.

Q Have you had discussions with him as part of your job responsibilities in this rate case?

A Yes, I have.

Q At any time did you talk to Mr. Fisher about how such a calculation might be performed?

A Well, he never asked me.

Q But in formulating your recommendations that Edison perform that calculation, did you ever ask Mr. Fisher whether such a calculation could be performed?

A No, I did not ask him. I felt that if he needed direction or questions on any of my recommendation, he had the opportunity to data request and ask me to provide guidance.

Q Let's look further on this same page at lines, again, lines 6 through 8. There is a second item in that second bullet that Edison provide the implicit inflation rate for future asset removal costs. Now, again, referring to the 2006 general rate case, are you aware the Commission had already directed Edison to provide that information?

A Yes, I am.

Q In fact, let's look at that, page 208 from the decision excerpt that I gave you. Do you have that in front of you?

A Yes, I do.

Q Do you see on the first full paragraph on that page, the third sentence where the Commission said: In its next GRC SCE should, as part of its account-by-account analysis, analyze the effects of past inflation on its proposed cost of removal rates and justify the implicit inflation rates reflected in its proposed rates.

Is this essentially what you had in mind?

A That is correct.

Q You are aware that Edison did provide that information in its testimony and workpapers?

A Yes, they did.

Q You are not proposing anything different then?

A No.

Q Is there a reason why you made this recommendation separate from what the Commission already ordered us to do?

A Well, they should be -- what I actually had in mind was -- yeah, yeah. I think that I was thinking of something that should be filed with the Commission on an annual basis. But taking a look at it now, I think it is supposed to be a three-year thing when the GRC is filed. And I think they've complied with that.

Q Did you use this information on the effects of past inflation, and so forth, that we were just discussing? Did you use that information in any way in your analysis?

A Well, my recommendation on depreciation in this case, in this proceeding, is to retain SCE's rates. And that was purely based on policy consideration from DRA.

Q So if I could get a direct answer. I was asking you whether in your analysis you in any way used this information about the effects of past inflation,

the one we were just discussing? Did you in any way use that as part of your analysis?
A I looked at it. I did not use it.
Q Directing you again back to page 18 of your testimony, lines 15 through 17, another one of your recommendations is that SCE be required to separate the accrual for cost of removal from accruals for depreciation expense when it files its annual depreciation rate schedule with the Commission; is that correct?
A That is correct.
Q You were here earlier today when Mr. Finkelstein was cross-examining Mr. Fisher; right?
A Right.
Q And you recall that one of the exhibits, one of the cross-examination exhibits that Mr. Finkelstein asked Mr. Fisher about was the annual depreciation reports that Edison files with the Commission?
A That is correct.
Q And you are generally familiar with these annual depreciation reports, aren't you, Mr. Ayanruoh?
A Yes, I am.
Q As you testified earlier, you were previously a witness on depreciation issues. So would it be fair to say that you get copies of these annual filings to look at?
A Well, actually, I don't.
Q But you do have access to it? You could get

them, if you wanted to?

A Right.

Q Well, do you then review each of these annual depreciation rate schedules that Edison files with the Commission on a regular basis?

A Well, I do review them when they file GRCs.

Q Could you just give me an estimate, say over the past five years about how many of those Edison annual depreciation rate schedules you have looked at?

A Over the past one year?

Q Past five years.

A Maybe two, three.

Q Okay. Let's again look at page 18 of your testimony in DRA-18. At lines 10 through 13 there is another -- there is the third bullet on this page. Another recommendation is that SCE be required to provide a five-year projection of the year-end balance prefunded removal costs showing for each year the gross additions to the balance, gross expenditures for removal cost and the net change in the balance of prefunded removal cost. Is that again one of your recommendations?

A That is correct.

Q You haven't changed that in any way?

A No, I have not.

Q Did you provide any examples, calculations or explain how Edison is supposed to perform this calculation?

A I did not.
Q And again, similar to my previous questions, have you had any discussions with Mr. Fisher here about this topic explaining what it is you had in mind or how he was supposed to perform that?
A My answer would be the same. Being that if he had difficulties or problems with it, he would have called or sent me a DR.
Q Thank you. I have no further questions. Thank you Mr. Ayanruoh.
A Thank you.
Q I do have one other thing, your Honor, I'm sorry.
I intended to ask you: With reference to what has been marked as Exhibit SCE-49 --
A Yes.
Q -- do you have that in front of you, Mr. Ayanruoh?
A I do.
Q Do you recognize this as containing data request and your responses? This is the Data Request SCE-DRA-059-DEPREC-BEN.
A Yes, I recall.
Q And these are your responses to those data requests?
A Yes, they are.
Q And as Mr. Finkelstein asked you earlier, if you were to be asked these same questions today, would

your answers be the same?

A Yes, they would.

Q Then directing you to one last exhibit, exhibit that has been marked as Exhibit SCE-50, this contains on the first couple of pages the transmittal letter from Mr. Gallagher to Mr. Pierce regarding receipt of Edison's annual depreciation rate filings. Do you recognize them?

A Yes, I do.

Q And the next page is Mr. Pierce's transmittal letter to Mr. Clanon of that depreciation rate schedule. In fact, this is the same document, one of the same documents Mr. Finkelstein was discussing earlier today. Do you recognize this?

A I recognize it, but not the attachments to that document.

Q Following that cover page are several excerpts from Mr. Fisher's workpapers in this proceeding. Do you generally -- I'm sure you don't have total recall of all the workpaper pages, but do these generally look familiar to you?

A Yes, they do.

Q You did review Mr. Fisher's workpapers as part of your review in this proceeding?

A Yes, I did.

MR. MC NULTY: Thank you.

At that point, your Honor, I have no further questions.

ALJ DE ANGELIS: Okay. Any redirect?

MS. SALVACION: No, your Honor.

ALJ DE ANGELIS: All right.

MR. MC NULTY: I would move for receipt of Exhibit SCE-49 and SCE-50, with the statement I made earlier that there may be some duplication between this and other material that Mr. Finkelstein referred to.

MS. SALVACION: Actually, your Honor, can I have a moment?

ALJ DE ANGELIS: Let's go off the record.

(Off the record)

ALJ DE ANGELIS: Back on the record.

Any objections to the receipt into evidence of SCE-49 and 50?

MS. SALVACION: No, your Honor.

ALJ DE ANGELIS: All right.

(Exhibit Nos. SCE-49 and SCE-50 were received into evidence.)

MS. SALVACION: If DRA can move DRA-18 and -20 into the record?

ALJ DE ANGELIS: Okay. Any objections?

(No response)

ALJ DE ANGELIS: Your request is granted.

(Exhibit Nos. DRA-18 and DRA-20 were received into evidence.)

ALJ DE ANGELIS: Any additional exhibits to move into evidence?

MR. MC NULTY: Yes. And first, your Honor, there is a clarification I need to make on the exhibit numbering for Mr. Fisher. What has been labeled as Exhibit SCE-11C should have been labeled SCE-11D. And his testimony, Exhibit SCE-24B should have been labeled 24C.

(Exhibit Nos. SCE-11C was revised to SCE-11D; SCE-24B was revised to 24C.)

ALJ DE ANGELIS: Okay. Thank you for that clarification.

MR. MC NULTY: And I would like to move for receipt of several exhibits for witnesses that -- for exhibits where the witnesses have finished testifying.

ALJ DE ANGELIS: Okay.

MR. MC NULTY: Did you want to excuse Mr. Ayanruoh first?

ALJ DE ANGELIS: You are excused. Thank you.

MR. MC NULTY: May I proceed?

ALJ DE ANGELIS: Go ahead.

MR. MC NULTY: There is a number of exhibits I would like to read off and ask for receipt into evidence. Exhibit SCE-65, which dealt with human resources testimony, Volume 1; Exhibit SCE-06C, which was an appendix to that testimony on human resources; Exhibit SCE-09, the subject matter was enterprise resource planning; Exhibit SCE-11A, which was results of operation testimony, Volume 1; Exhibit SCE-11C, which was confidential results of operation testimony, Volume 2C; Exhibit SCE-12, which was productivity testimony;

Exhibit SCE-25, which was rebuttal testimony on productivity; Exhibit SCE-27, which was results of examination rebuttal; Exhibit SCE-25WP, which was the workpapers to Exhibit SCE-25 on the DSRP subject; Exhibit SCE-45, which was errata; Exhibit SCE-46, which was also errata; exhibit SCE ---strike that. We will wait on that, since Mr. Worden hasn't yet appeared. There are a couple of exhibits dealing with him.

ALJ DE ANGELIS: Okay.

MR. MC NULTY: And I believe that is it. I've already move into receipt SCE-49 and -50. I think that would do it, your Honor. Thank you.

ALJ DE ANGELIS: Okay any objections?

MS. SALVACION: No.

ALJ DE ANGELIS: Your request is granted.

(Exhibit Nos. SCE-65; SCE-06C; SCE-09; SCE-11A; SCE-11C; SCE-12; SCE-25, rebuttal testimony; SCE-27; SCE-25WP; SCE-25, DSRP subject; SCE-45; SCE-46 were received into evidence.)

MR. MC NULTY: Thank you, your Honor.

MS. TUDISCO: On behalf of DRA there were several exhibits that were identified and not moved into evidence, if I may enumerate them now?

ALJ DE ANGELIS: Please.

MS. TUDISCO: At page 11A a handout, I was given DRA-40, DRA-41, DRA-42, and DRA-43.

ALJ DE ANGELIS: Okay. Any objections?

(No response)

ALJ DE ANGELIS: Your request is granted.

(Exhibit No. DRA-40, DRA-41, DRA-42, and DRA-43 were received into evidence.)

MS. TUDISCO: Then on page 13, DRA-80, DRA-81, DRA-82, DRA-83, DRA-84 and DRA-85.

ALJ DE ANGELIS: Any objections?

(No response)

ALJ DE ANGELIS: Your request is granted.

(Exhibit No. DRA-80, DRA-81, DRA-82, DRA-83, DRA-84 and DRA-85 were received into evidence.)

MS. TUDISCO: The only other thing I would like to note, what is on this list as page 9 as DRA-06 was given the number of DRA-73. That is the testimony of Truman Burns. It was -- it has been moved into the record as DRA-73, not DRA-06. It looks like it is blank, and that is why.

ALJ DE ANGELIS: Okay. Thank you for that clarification.

MS. TUDISCO: Thank you, your Honor.

ALJ DE ANGELIS: All right. Anything else before we go off the record and adjourn for the day?

(No response)

ALJ DE ANGELIS: Okay. We will be back at 9:00 tomorrow.

Off the record.

(Whereupon, at the hour of 2:25 p.m., this matter having been continued to 9:00 a.m., June 16, 2008, at San Francisco, California, the Commission then adjourned.)

TAB D

PG&E AMI Decisions

1. **CPUC Decision 06-07-027**
   (See Marked Pages 24 to 27; 43 to 44)

2. **CPUC Decision 09-03-026**
   (See Marked Pages 23 to 26;
   133 to 135)

Decision 06-07-027 July 20, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced Metering Infrastructure. (U 39 E)	Application 05-06-028 (Filed June 16, 2005)

(See Appendix A for List of Appearances.)

FINAL OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY TO DEPLOY ADVANCED METERING INFRASTRUCTURE

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FINAL OPINION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY TO DEPLOY ADVANCED METERING INFRASTRUCTURE

This opinion authorizes Pacific Gas and Electric Company (PG&E) to deploy a new Advanced Metering Infrastructure (AMI). We adopt a modified revenue requirement and guaranteed ratepayer benefits. The ratemaking mechanisms will be in place at least until PG&E's next general rate case which we expect to occur for test-year 2010 or later. We also adopt PG&E's rate proposal for critical peak pricing tariffs. This proceeding is closed.

1. Background

The Commission opened Rulemaking (R.) 02-06-001 as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment.[1] This application emerged from the Rulemaking and is PG&E's proposal for full deployment of an advanced metering infrastructure. PG&E's application seeks authorization of its AMI deployment proposal and associated cost recovery mechanisms.

AMI consists of metering and communications infrastructure as well as the related computerized systems and software.[2] 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.[3]

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[1] *Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing*, filed June 6, 2002. The Commission's rulemaking named as respondents the following investor owned utilities: PG&E, San Diego Gas & Electric, and Southern California Edison Company. The Rulemaking was closed by Decision (D.) 05-11-009, dated November 18, 2005.

[2] PG&E's AMI project includes automation of its gas and electric metering and communications network (5.1 million electric meters and 4.2 million gas meters).

[3] PG&E's plan is to retrofit 54% of the existing electric meters and 96.1% of its existing gas meters.

PG&E revised its application on October 13, 2005. As amended, the application requests that the Commission approve PG&E's recovery of the actual AMI deployment cost without further reasonableness review if the actual cost is less than or equal to $1.61 billion,[4] and to recover additional reasonable amounts, if any, upon appropriate reasonableness review. PG&E also proposes new balancing accounts to track actual costs and pre-approved benefits of the AMI deployment. Because deployment will reduce certain current operating costs, PG&E proposes refunding a forecast per-meter benefit, tied to the actual AMI deployment.

PG&E proposes to change rates on July 1, 2006, and again on January 1 of 2007, 2008, and 2009 to recover the approved forecast revenue requirements for the AMI project. PG&E's rate changes are based on the balancing account balances that record for actual costs for AMI and credits benefits in the form of operating savings, as estimated for each rate change date. The AMI costs include the rate effect for estimated plant additions, and annual depreciation. PG&E also seeks limited authority to temporarily estimate bills while PG&E tries to obtain physical access to the meter to install the AMI modules.

1.1. Prior Approval of Pre-Deployment Funding

In D.05-09-044,[5] the Commission authorized PG&E to spend and recover in rates up to $49 million in advance of any possible approval in this proceeding for a full-scale deployment. The Commission stated:

> …it is worth noting that although PG&E's policy arguments for approval of its AMI predeployment expenses largely rest on the demand response benefits of AMI, PG&E's case, as presented in A.05-06-028, asserts that the majority of the benefits of the deployment would be operational. That

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[4] Revised from an original estimated cost of $1.46 billion, consisting of an estimated capital cost of $1.25 billion, estimated expense of $213 million.

[5] Application (A.) 05-03-016, filed March 15, 2005.

> is, deployment of AMI would actually be nearly cost-effective from a utility operations point of view with the potential to save the utility costs over time. The various versions of PG&E's AMI business case that have been submitted in R.02-06-001 over time have shown steady progress in improving the cost-effectiveness of AMI such that less of the benefit would need to be covered by demand response peak demand cost savings. With this in mind, and although we have not yet thoroughly evaluated PG&E's cost-effectiveness claims in A.05-06-028, our sense is that PG&E's AMI deployment, if approved, will have at least some significant benefits to the utility beyond demand response. Therefore, and for all the reasons stated above, we will approve PG&E's request for $49 million in pre-deployment expenses for AMI, as reflected in more detail in Section 8 below.
>
> We remind PG&E that this authorization, while separate from the issues to be decided in A.05-06-028, nonetheless sets the Company on the path of designing and building systems that will one day become new infrastructure. Therefore, **we advise once again that we wish to promote open architecture standards, uniform business practices, and data exchange standards**. … (*mimeo.*, pp. 13-14, emphasis added.)

The Commission also made three significant findings and conclusions about PG&E's proposed AMI project:

- The AMI system selected is sufficiently flexible to accommodate different approaches to rate design and informational tools.
- PG&E's proposed AMI Project will meet the minimum functionality criteria established by Commissioner Peevey. (Findings of Fact 1 and 2, *mimeo.,* p. 20.)
- The finding that PG&E's proposed AMI Project meets the minimum functionality criteria does not establish that the system selected by PG&E is the correct or best system, or provides the best value for ratepayers. These are issues to be decided in A.05-06-028. (Conclusion of Law 2, *mimeo.,* p. 21.)

The above findings of fact and conclusion of law allowed PG&E to continue with the development of the AMI project included in this application.

2. Procedural History

Notice of the application appeared in the Commission's Daily Calendar on June 20, 2005. Resolution ALJ 176-3155 dated June 30, 2005, preliminarily categorized the application as ratesetting and determined that hearings were necessary. A prehearing conference was held on July 14, 2005 and an Assigned Commissioner's Ruling on the scope of the proceeding was subsequently issued on July 27, 2005. The scoping ruling confirmed that this was ratesetting proceeding and evidentiary hearings were necessary.

Testimony was served on January 18, 2006 by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Californians for Renewable Energy, Inc., The South San Joaquin Irrigation District (SSJID), The School Project for Utility Rate Reduction (SPURR), Hunt Technologies and Cellnet Technologies, e-Meter, and The County of Yolo and Cities of Davis, West Sacramento, and Woodland (Yolo/Cities). PG&E, DRA and TURN served rebuttal testimony on February 8, 2006. Evidentiary hearings were held between February 28 – March 16, 2006. The Silicon Valley Leadership Group (SVLG) was permitted to intervene late on February 28, 2006. Also, SVLG was permitted to serve late testimony. Opening briefs were filed by all parties on April 3, 2006 and reply briefs on April 14, 2006.

The record is composed of all documents that were filed and served on parties. It also includes all testimony and exhibits[6] received at hearing and late-filed exhibits as ordered by the Administrative Law Judge (ALJ). Also, the ALJ sealed as confidential various exhibits and portions of the transcript and allowed TURN and PG&E to file portions of briefs as confidential. We affirm all ALJ rulings on confidentiality.

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[6] There were 110 exhibits received into evidence – many were large multi-chaptered documents sponsored by several witnesses.

2.1. Stipulations

DRA and PG&E entered into a number of evidentiary stipulations, all of which were reduced to writing and admitted as exhibits.[7] As a result of the stipulations, PG&E and DRA now agree on the project installation and deployment costs, and all operational benefits and costs. No other party opposed the stipulations.[8] We find that these stipulations are within the range of reasonable outcome if the matters were fully litigated on the existing record. Therefore, we will adopt the stipulations. We find, based upon the prepared testimony, that DRA has performed sufficient competent analysis to enter into an informed agreement with PG&E in the various stipulations. We adopt the final calculation of operational benefits and costs as modified by the stipulations, and as discussed herein.

3. Scope

To evaluate the deployment request, the Commission must decide whether: the proposed systems meet the functionality criteria set forth in the Assigned Commissioner Ruling of May 18, 2005; the correct technology has been selected; the project is cost-effective; to allow recovery of the actual project costs without further reasonableness review; to adopt a critical peak pricing proposal; and to adopt any other necessary ratemaking provisions necessary to implement AMI. As found by this decision, the AMI project satisfies the requirements set out in the scoping memo.

4. Positions of the Parties

4.1. PG&E

PG&E argues that it "has proposed a viable, cost effective AMI Project that will transform PG&E's business significantly, improve customer service and satisfaction, and

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[7] Exs. 16, 17, 19, 20, 28 and 29.

provide the Commission with a powerful tool for shaping California energy policy." (PG&E's Opening Brief, p.1.) PG&E's policy witness testified that the AMI deployment should be approved because it possesses the following reasonable features: (a) cost effectiveness, (b) voluntary (opt-in) participation in demand response rates, (c) rates can remain almost flat, (d) improved customer service, (e) implements state and regulatory energy policy goals, and meets the Commission's desired functionality requirements, and (f) reasonably addresses labor impacts. (Ex. 1, pp. 1-1 and 1-2.)

4.2. DRA

DRA supports PG&E's project only if it is cost-effective and with the caveats now captured by stipulations. DRA states that the Commission "should … ensure that the potential benefits are realized. It should also adopt ratemaking mechanisms that ensure that ratepayers share in the benefits. It should direct PG&E to … mitigate the risks of using a proprietary technology. Finally, the Commission should require periodic reports from PG&E" describing deployment and technological problems. (DRA's Opening Brief, p.1.)

4.3. TURN

TURN argues that the "AMI project is not cost effective, and, as such, the Commission should not approve this application. … PG&E bases its business case analysis on an overly optimistic demand response forecast, an incorrect avoided generation cost value, and an uncertain 20-year economic useful life and study period." (TURN's Reply, p. 1.) TURN's testimony (Ex. 201) suggests the Commission should reject the proposed AMI deployment, or at least require specific changes. TURN opposes approval or recommends changes because the project is not cost effective – there is a $523 million gap from operations (based on only a 15-year study) and only $90

[8] TURN broadly opposed the AMI project, including its costs, benefits and other issues, but it raised no objection to the stipulations. Our adoption of the stipulation denies any of TURN's

Footnote continued on next page

million in demand response benefits under the TURN High Case. TURN also recommends that the Commission require PG&E to develop a new business model that includes open architecture in the entire network and re-file that new business model.

If AMI deployment is approved, TURN then recommends that the Commission require PG&E to:

- indemnify ratepayers against premature retirement prior to the end of PG&E's proposed 20-year life,
- flow through program costs and operational benefits using a mortgage amortization to eliminate intergenerational inequities with front-loaded capital costs in the early years and benefits increasing with inflation in the later years,
- install AMI meters in new construction at the time of the original meter set even if networks are not available in those areas to hook up the AMI to reduce duplicative and expensive labor costs,
- request demand response funding in 2009 and beyond on an ongoing basis rather than pre-approving it in this case in light of uncertainties in future demand response penetration,
- as a condition of the approval of this application, to obtain from the vendors an agreement (at no additional cost to PG&E) that the vendor will license its technology at nominal cost so that all vendors of smart thermostats can use it, thereby mitigating potential monopolization of the market for a device soon to be mandated by the California Energy Commission. (TURN Ex. 201, pp. 2 – 3.)

4.4. SPURR, SVLG and eMeter

SPURR, SVLG and eMeter all support AMI deployment. They also support SPURR's and SVLG's proposal for open, automated, non-discriminatory, and real-time access to AMI data, as discussed elsewhere in this decision.

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remaining objections on these issues.

4.5. SSJID and Yolo/Cities

SSJID and Yolo/Cities have contested condemnation proceedings to acquire PG&E's service territory and thereafter SSJID intends to provide electric service to customers in its service territory and Yolo/Cities would switch to the Sacramento Municipal Utility District (SMUD). They therefore request that PG&E should not be allowed to deploy AMI in the disputed territory because they believe the equipment would not be useful if service is provided, respectively, by SSJID and SMUD.

5. Overview

As discussed in this decision, we conclude it is reasonable for PG&E to deploy AMI, as modified in this decision, because we find PG&E's proposal has sufficient probable and quantifiable economic operating and demand response benefits now, including sufficient flexibility to up-grade for enhanced features, over the expected 20-year useful life. PG&E's AMI project business case analysis shows approximately 90% of the project costs would be covered through operational savings, on a net present value basis (Ex. 5, pp. 1-1 through 1-7). The additional 10% is expected to be covered by demand response benefits from the Critical Peak Pricing (CPP) tariff. (Ex. 1, p.1-1.) The incremental revenue requirement needed to pay for the AMI project is approximately one percent[9] of PG&E's combined gas and electric revenue requirement (estimated by PG&E using a 15-year Present Value of Revenue Requirements (PVRR)).

There is sufficient discretion in our AMI requirements, and the likelihood of long-term benefits – from utility operating cost savings as well as demand response and consumer energy consumption management potential - that the project merits approval. Further, AMI can provide improved customer data so that in the future rates may be set to more equitably allocate electricity costs. Also, PG&E will be able to more accurately forecast load and identify load centers. We find that the proposed AMI has a closed or

[9] Ex. 1, p. 1-2.

proprietary architecture but it does not preclude outside vendors from developing other applications such as consumer-side of the meter communication and load control devices. We believe that given the uncertainty of any very long-term forecast (in this case for operational savings and demand response effects forecast for the next 20 years), we must act with the best information now even though we know no forecast is ever fully accurate. We also recognize any failure to act loses the tangible benefits that can be achieved with the proposed system.

TURN suggests that the scope of the AMI project is excessive to implement critical peak pricing "in order to charge fewer than 15% of PG&E's customers higher prices for up to 75 hours" per year. (TURN's Opening Brief p. 4.) This ignores the potential of AMI to allow the Commission to more accurately allocate costs and fairly reflect the true cost of service in energy rates to all customers. In subsequent proceedings, with adequate time and an appropriate record, AMI opens the door to true real-time pricing which accurately reflects the cost of energy.

TURN has not moved forward from its posture in R.02-06-001 where the Commission found: "TURN does not support universal deployment of advanced meters, but believes there may be specific applications of dynamic pricing and advanced meters that provide meaningful demand reduction and participant savings for small customers. However, it feels that inquiry has been sacrificed in this rulemaking for an "all or nothing" approach." (D.03-03-036, *mimeo.*, pp. 19-20.) We will therefore address those aspects of TURN's showing that productively contributed to develop and interpret the record developed here to determine whether or not to deploy PG&E's proposed AMI project.

We now discuss specific aspects of PG&E's proposal.

6. Project Management

PG&E provided extensive testimony on the integrated project management structure and controls it intends to use to manage the project. PG&E has assigned senior management for oversight of the project and ensured that managers with appropriate expertise are accountable for project performance to an Executive Steering Committee. PG&E's project management process includes audits and performance reviews by PG&E's Internal Audit staff and an outside consultant (PricewaterhouseCoopers).[10] No party objected to PG&E's proposed project management structure and we find this structure to be reasonable for AMI deployment.

6.1. Risk Management

As a part of the project costs, PG&E included what it described as a Risk-Based Allowance or a contingency of $128.8 million. If one part of the project exceeds budget then there is a process for project managers to "draw-down" or authorize the use of the contingency to complete the project. In effect, by approving the proposed budget, the Commission explicitly allows PG&E the discretion to spend $128.8 million to address delays, overruns or other unforeseen contingencies as a part of the reasonable costs of the project. DRA supports the contingency. (PG&E's Opening Brief, p.14, and the stipulation in Ex. 28.)

TURN is concerned that ratepayers will have a variety of significant risks, as well as risks of cost overruns, in excess of the risk-based allowance included in the forecast. (TURN's Opening Brief, pp.10 – 17.) However, most of TURN's argument appears to be an attempt to rehear the initial Rulemaking. TURN opposes the AMI project as too broad, too complex, and unnecessary to achieve the operational benefits that may be accomplished with an unidentified but simpler automated metering reading.

TURN is unpersuasive and repetitive on the matter. For example, we disagree that the equipment is new or untested. (TURN's Opening Brief p.10.) PG&E's witnesses from DCSI demonstrated that DCSI has several successful deployments that have operated for several years. We are also not persuaded that the arguments by TURN concerning information technology project delays and overruns are directly applicable

[10] Ex. 11, Ch. 2, p. 2-9, and transcript, pp. 234 – 237.

here. TURN has not shown that its anecdotal information on large informational technology applications is applicable to the AMI project. We therefore approve the inclusion of a risk-based contingency in the approved project cost forecast.

6.2. Cost Overruns

In addition to the risk-based allowance included in the deployment cost forecast, PG&E and DRA stipulated (Ex. 28) to project cost recovery even if the Commission adopted a different revenue requirement than agreed to between PG&E and DRA. The stipulation includes:

1. $1.6846 billion of project costs would be deemed reasonable and recovered in rates without any after-the-fact reasonableness review.
2. 90% of up to $100 million in project costs beyond the $1.6846 billion, if any, would also be deemed reasonable and recovered in rates without any after-the-fact reasonableness review. The remaining 10% will be absorbed by PG&E's shareholders.
3. Costs in excess of $100 million over the $1.6846 billion will be recoverable only if approved by the Commission in a reasonableness review.

The stipulation also provides for cost overruns due to events beyond PG&E's control which may be recovered by PG&E, with Commission approval, without the 10% shareholder penalty described above. These include material changes in the project's scope by governmental or regulatory actions, delay in approving this application beyond September 21, 2006, delays caused during deployment by cities and local governments, and force-majeure events.[11]

We note that the force-majeure paragraph includes a descriptive list including two items, "transportation accidents" and "strikes or other labor disturbances…" (Ex. 28, p. 3.) where it is conceivable that PG&E could be a participant rather than an innocent

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[11] Force-majeure clause: "A contractual provision allocating the risk if performance becomes impossible or impracticable as a result of an event or effect that the parties could not have anticipated or controlled." (Black's Law Dictionary, 7th edition, p. 657.)

victim as it would be during an earthquake (also on the list). PG&E must clearly demonstrate that any claim of force-majeure was in fact beyond PG&E's ability to anticipate or control.

Force-majeure should only include transportation accidents when PG&E can demonstrate that it was neither intentionally nor negligently responsible for any transportation accident-related delays to the project.

We are also concerned that the force-majeure language might excuse PG&E's actions during a labor dispute with its own workforce. Therefore, we will exclude from the force-majeure list "strikes or other labor disturbances" involving PG&E, or its vendors or contractors.

We will only allow PG&E to seek recovery of costs due to transportation accidents or labor disputes, in the event that all overruns exceed the $100 million shared range and PG&E can demonstrate the reasonableness of its actions and costs at the time. However, PG&E cannot recover these costs as force-majeure.

We find that the modified stipulation concerning overruns is reasonable. Under this modified stipulation PG&E will have an incentive (the 10%/$10 million exposure) to minimize and mitigate overruns. There is also an administrative efficiency to avoid litigation when a $90 million exposure for the ratepayer represents an added 5.34% of the forecast $1.6846 billion in project costs. We therefore adopt the stipulation on overruns, as modified for force-majeure.

6.3. Deploy Meters in New Construction

TURN suggests that PG&E should deploy AMI equipped meters in new construction to avoid duplicate efforts when a territory is subsequently fully converted to AMI. As a concept, we agree duplication should usually be avoided, but there is no hard data to support an absolute requirement at this time. Therefore, we direct PG&E to consider where it may be appropriate to pre-deploy AMI equipped meters (such as in a new tract home construction or small commercial developments). Where PG&E pre-deploys AMI for new construction, it may record the costs in the balancing account at the time of deployment and defer recording the per-meter benefits until the entire territory is converted. We will allow costs into the balancing account so that PG&E has no disincentive to defer reasonable early installations. We recognize that the benefits do not accrue until the entire territory is converted to the AMI network. (See also the later ratemaking and balancing account discussion.)

6.4. Deferred Deployment

Yolo/Cities all have contested pending condemnation proceedings to acquire PG&E's service territory and displace PG&E as the incumbent utility. They collectively request that the Commission direct PG&E to defer deployment in their locations because they believe the AMI technology will be an unnecessary cost burden to them by endangering the acquisition or needlessly raising the assessed acquisition value of PG&E's distribution facilities. They further argue the AMI system could be useless to them.[12]

PG&E has indicated that its system-wide deployment will take five years to complete but it is unwilling to delay deployment in the Yolo/Cities prospective territories.[13] The record does not show precisely when PG&E intends to convert the Yolo/Cities territories. Based on a data response in discovery PG&E may install AMI modules in the disputed territories sometime between July 2007 and August 2008. (Ex. 701, p. 4.)

SMUD filed an annexation application to the Sacramento County Local Agency Formation Commission on July 29, 2005. On November 18, 2005, this Commission

[12] Ex. 701.

[13] PG&E's Opening Brief, p. 25, PG&E suggests that it is "premature" to direct PG&E to delay deployment. But this is precisely the right time to provide guidance: before PG&E deploys the AMI equipment in territory which it may forfeit to SMUD.

issued a resolution finding the annexation would not substantially impair PG&E.[14] (Ex. 701, p. 1.) Yolo County may have an election on SMUD annexation in November 2006. We can avoid needless expense by deferring AMI deployment in the Yolo/cities territories until the election is resolved.

We therefore direct that (1) PG&E shall refrain from installing AMI infrastructure in the potential Yolo/Cities annexation territories before the November 2006 election, and (2) in the event the Yolo County election approves the SMUD annexation, PG&E shall not install AMI infrastructure in the annexation territories without further direct authority from this Commission. Furthermore, if the annexation election fails, PG&E may not install AMI infrastructure in the annexation territories until any legal challenge of the election is final.

6.5. Reporting and Monitoring – Proposed Stipulation

DRA proposed that PG&E should report the status of the project on a regular basis and DRA should be able to actively monitor the project. (Ex. 101, Ch. 2, p. 2-29 and DRA's Opening Brief, pp. 14 – 15.) PG&E responded that the Commission would receive sufficient details in the ongoing balancing accounts. (Ex. 5, Ch. 2, p. 2-5.) Later in the proceeding there was a near-stipulation (Ex. 34-P) where PG&E would provide DRA and the Energy Division a regular summary report of the following information as is provided to PG&E's Executive Steering Committee on the status of the Project: (1) Project status; (2) progress against baseline schedule including equipment installation and key milestones; (3) actual Project spending vs. forecast; and (4) risk-based contingency allowance draw-down status (discussed elsewhere in this decision).[15]

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[14] Resolution E-3952. *See* Finding 11: "A potential rate impact of this magnitude would not substantially impair PG&E's ability to provide adequate service at reasonable rates within the remainder of its territory." (http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/51504.DOC).

[15] Ex. 34-P, lines 10-19. (Various suffixes were used for certain exhibits: C denotes Confidential exhibits, W for work papers related to the root exhibit, E for errata and P for

Footnote continued on next page

The parties did not reach closure on the stipulation text by the ALJ's imposed deadline of five work days after the close of hearings. (Transcript, pp. 1380 – 1384.) It is not necessary for the parties to agree in order to find the proposed stipulation's reporting to be a reasonable and useful tool to the Commission and perhaps DRA. No party objected to any specific component of the proposal. Therefore, we will adopt the proposed reporting disclosure illustrated in Ex. 34-P and direct PG&E to serve copies on DRA and the Energy Division. PG&E may submit these reports pursuant to Pub. Util. Code § 583.

6.6. Summary of Project Management

We find that PG&E has demonstrated it will use an appropriate management structure to effectively control the AMI project. With the addition of a regular summary report on the status of the Project provided to the Energy Division and DRA (containing the same information provided to PG&E's Executive Steering Committee) the Commission will have timely access to necessary project information including untoward events, schedule delays or cost overruns. We therefore approve the project management component of the AMI deployment project, modified for possible early installation in new construction and deferring deployment in the Yolo/Cities territories.

7. Technology

PG&E selected Distribution Control Systems, Inc. (DCSI) to provide a Power Line Carrier technology for electric meters and Hexagram, Inc. to provide a fixed network system with radio frequency communication channels owned by PG&E for gas meters.[16] These selections followed a detailed Request for Proposal (RFP) and evaluation process. PG&E's testimony showed that the DCSI system has been deployed by a

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Provisional. All exhibits identified and received in the transcript – regardless of the supplemental numbering notations - are a part of the formal record for this proceeding.)

[16] Ex. 1, Ch. 2, p. 2-13.

number of other utilities (none as large as PG&E) to provide a sufficient demonstration of the technology's reliability and functionality. The technology provides two-way communications to each customer's meter. The technology also allows other functions including direct polling to the meter by PG&E which can assist in completing customer service related requests; and it has the potential for direct communication with in-home devices like thermostats and load control switches.

DRA's AMI technology consultant concluded "(t)he systems selected by PG&E are reasonable, relatively mature, and have evolved to strike an acceptable balance in cost, functionality and flexibility."[17] TURN expressed reservations about the scope of the RFP and, as noted elsewhere, the concern that remote meter reading could be accomplished with a less comprehensive system.

7.1. Functionality Criteria

Although the Commission found in D.05-09-044 that PG&E's proposed AMI system met the functionality requirement (Finding of Fact 2), it also concluded that we must still find "that the system selected by PG&E is the correct or best system, or provides the best value for ratepayers." (Conclusion of Law 2.) This follows on the Assigned Commissioner's directive that "we must be able to make an affirmative finding that the proposed systems meet the functionality criteria set forth in the *Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis* issued February 19, 2004 in Rulemaking (R.) 02-06-001." (*Assigned Commissioner Ruling* of May 18, 2005.) This followed a still earlier ruling in R.02-06-001 that delayed the proceeding to allow "… the California Energy Commission to host a technical conference to begin the process of developing open architecture standards for advanced metering infrastructure." The Ruling continued that the "(f)ree flow of data … is crucial to the economics of the

[17] Ex. 101, Ch. 2, p. 2-11.

investment we are considering and the long-term viability of the systems the utilities will consider installing. Ideally, we would like to see national standards for data exchange …" (*Assigned Commissioner and Assigned ALJ Ruling* of November 24, 2004.)

We know from PG&E and its vendor that the proposed AMI system is not an open architecture design.[18] It is a proprietary design, which requires either a licensing agreement for other suppliers to use the AMI communications system, or a second communications system that operates around the AMI network, to communicate with customers or at their appliances.

PG&E and DRA both testified that the proposed system meets the Commission's functionality requirements to provide PG&E operational efficiencies, improve information about the operating system, and permit PG&E to offer time-sensitive rates.[19] Further, the system will allow two-way communication between PG&E and the meter (and potentially the customer), which has both distribution system reliability and customer service benefits. The AMI system is designed to provide 15, 30, or 60 minute interval electric meter data for commercial customers, depending on the requirements for their respective rate, and hourly interval data for residential customers. This design is necessary for any future offer of more complex dynamic pricing for energy cost recovery.[20]

Only TURN opposed the selected technology as excessive in order to "charge fewer than 15% of PG&E's customers' higher prices [CPP rates] for up to 75 hours of the year." TURN also argued that the costs could easily exceed the forecast based on TURN's comparison of the AMI project to large-scale information technology computer-based systems. (TURN's Opening Brief, p.18.)

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[18] See transcript, March 19, 2006, portions of which are confidential, and Ex. 11, Chapters 4 & 5.

[19] Ex. 2, Ch 1, p. 1-2 (PG&E) and Ex. 101, Ch. 2, p. 2-2 (DRA).

[20] Ex. 2, Ch. 1, p. 1-4.

We believe that TURN takes too narrow a view of the scope and long-term applications for the AMI project and we are not persuaded that the selected project technology is inappropriate. As already discussed, we accept the cost forecast as robust and inclusive of a reasonable allowance for overruns. We do not believe that AMI module-equipped meters, with a service life of 20 years, will only be used for CPP rates. They will provide significant operating data and consumption data with many applications in demand forecasts, service-related issues, and rate design.

TURN's posture throughout the proceeding revolves on its belief that the Commission is using AMI to implement an "ideological commitment to promoting future retail competition in the residential sector" (TURN's Opening Brief, p. 1) and "the subsequent Rulings of Assigned Commissioner Peevey have doggedly and unwaveringly pursued the single objective of promoting the universal deployment of hourly metering capability as requested by the meter vendors who filed the Petition to Modify D.97-05-039."[21] (Opening Brief, p. 3.) In short, TURN fears an attempt to revive the deceased electric restructuring of the mid-1990s.

This decision does not restart direct access nor does it directly foster retail competition. The three principal benefits of AMI as discussed throughout this decision are (1) the numerous operational benefits including improvements to system and procurement planning; (2) the potential for more accurate cost allocation and rate design because of accurate hourly consumption billing data; and (3) timely and more detailed consumer awareness of energy consumption.

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[21] "After the development of retail direct access was terminated due to the deregulation disaster, a group of meter vendors – self-styled as the California Consumer Empowerment Alliance - filed a petition to modify D.97-05-039 in March of 2002, requesting that the Commission require the utilities "to undertake universal installation of advanced meters to all customers on a mandatory basis."" (TURN's Opening Brief, p. 3, footnotes omitted.)

7.2. Open Architecture

Despite our avowed preference for an open architecture PG&E proposes adopting a confidential or proprietary system. This is, at least in part, as the record indicates, because there is no open AMI architecture (i.e., no established interoperability standards among vendors at the meter module level) available at this time.[22] With open architecture, the opportunity exists for competition in customer-side of the meter service and product competition using the consumption data and two-way communication link between the meter module and PG&E. Additional benefits could include operational and demand response potential with an AMI network.

We need not disclose the confidential terms but we are satisfied that the contracts between PG&E and the vendors contain adequate provision for technology licensing at fair prices that will promote the development of new in-home energy management products and services. We therefore find we can approve the deployment of a non-open architecture technology. This is based on findings in this decision of sufficient identified, probable and quantifiable, operational and demand response benefits.

7.3. Summary on Technology

The biggest concern is whether the proprietary nature of the AMI network is too important a short-coming in the project's design when we have a pronounced preference for open architecture. But there were no viable open architectural systems in the responses to PG&E's RFP. Therefore, we are faced with the choice of deploying or deferring AMI.

We find the operational benefits and the demand response benefits of critical peak pricing (discussed elsewhere in this decision), and the potential for future applications, even with a proprietary system, outweigh the benefits of waiting for an open architecture option. PG&E has obtained contract terms that will facilitate licensing the proprietary

[22] Ex. 101, p. 2-15.

design on commercially reasonable terms. Further, we know that the AMI communications module provides no bottleneck to preclude any other vendors' communication device or system from using the power line to communicate directly with smart devices (thermostats, switches, motors, etc.,) beyond the meter.[23] We therefore find that PG&E's proposed AMI system meets our functionality requirement and is a deployable technology.

8. The Meaning of Life

The "life" of the proposed AMI system has been addressed – and disputed – by the parties in a variety of ways. In this section, we define and adopt several necessary measurements and uses of the term "life."

8.1. Useful Life

First there is the question of what is the AMI system's "operational" or "service" or "useful" or "functional" life? The parties all use different shades of meaning. We will consolidate all of these terms into one: useful life. We define useful life to mean the continuous period of time when the components and system of the AMI project operate correctly and reliably to perform their designed functions. In regulatory jargon, this is the period when a system is considered to be "used and useful."

We find PG&E persuasive that the useful life of the system is 20 years. This finding is supported in the testimony of both PG&E's in-house expert and the senior officials from DCSI, the AMI equipment supplier. This finding is further supported by the confidential warrantee data included in PG&E's contracts for the AMI system components.[24] Without disclosing the confidential details, we find the warrantee to be sufficient to support the likelihood of a 20-year service life for the system in general. As

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[23] See transcript, March 19, 2006, portions of which are confidential, and Ex. 11, chapters 4 & 5.

[24] Ex. 11C, Chapter 4 for confidential warrantee terms. Ex. 11, pp. 5-1 – 5-3 for 20-year useful life.

with any complex system, individual components may fail early or last longer than the overall useful life. The AMI system's useful life does not depend on when the first component fails or how long the last meter-module can be coaxed to function. Its life depends on the system as a whole operating correctly and reliably. We therefore find a 20-year useful life is a reasonable forecast for the purposes of this decision.

8.2. Depreciable Life

The next term is "depreciable" life. The depreciable life is the period of time when ratepayers reimburse PG&E for the original long-term investment in long-lived assets.[25] Normally the depreciable life approximates the useful life so that ratepayers reimburse PG&E equitably over the entire useful life – otherwise between different periods of time ratepayers may not pay for equipment still used and useful because it is already fully depreciated. This is a "matching" concept in accounting – to match the costs to the service provided and charge a price that includes all the costs to provide service over the appropriate useful life. PG&E's witness testified that the new AMI components do not exactly fit any existing and authorized depreciation category; they are most similar to equipment included in a communications equipment depreciation category with a depreciable life of 15 years.[26]

The PG&E witness testified there has not been a depreciation study for the AMI communications equipment – which is reasonable given the few deployments and the short service lives to-date. Any study now for PG&E would be highly speculative.

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[25] The original costs to install the AMI project (or any long-lived asset) in our cost of service rate regulation regime are included in rate base and PG&E has an opportunity to earn a reasonable return on the outstanding balance over the useful life. PG&E is authorized in this decision to recovery a portion of the costs as depreciation expense, which is included in the annual revenue requirement that also includes a reasonable rate of return. As depreciation accumulates over time, the rate base and return on rate base decline until the asset is fully depreciated.

[26] Transcript, pp. 674 ff.

PG&E was not persuasive that we should use the 15-year communications equipment depreciable life for the AMI project. TURN recommended a 20 year depreciable life, correctly based on the Federal Energy Regulatory Commission's uniform system of accounts requirements for depreciation. (TURN's Opening Brief, p. 57.)

Absent any persuasive contrary evidence, the depreciable life should match the useful life. We will direct PG&E to depreciate the AMI equipment over 20 years and we will set rates using a 20-year life depreciation schedule. Like all other depreciable property, PG&E can re-examine the depreciable life in its subsequent general rate cases when there is credible evidence that the life should be adjusted. PG&E currently files a general rate case triennially; therefore, there should be several opportunities for timely depreciation studies before the end of the useful life of the AMI system.

8.3. Economic Life and Study Period

"Economic" life and "study period" are less synonymous than the previous types of lives. Again, the parties tended to confuse the record with these terms to support their particular viewpoints. We will define economic life as the period where the AMI system components correctly and reliably perform their designed functions and a new system would not be less expensive to own and operate. By contrast, the study period for this application – and as used in the predecessor rulemaking – was set as a matter of convenience and consistency at 15 years, so that all parties could use a constant period to forecast operational benefits, demand response benefits, and cost recovery. Fifteen years was also safely within an expected useful life before we had specific system proposals.

We asked for the 15-year study life solely as a consistent analytical tool and not as an expectation of absolute useful or economic life. PG&E presented its cost/benefit analysis in this proceeding based on a 20-year life consistent with its expectation of the selected system's useful life. TURN argues that the Commission should limit its review to a 15-year study period. DRA supports deployment regardless of a 15 or 20-year analysis.[27]

We chose to rely on the 20-year study because it more accurately reflects the likely useful life of the AMI system. Although longer-range forecasts may have a greater likelihood of deviating from actual results, a 15-year study is not significantly more accurate than a 20-year study, and it ignores the benefits contributed by a full quarter of the useful life of the AMI system.

8.4. Technological Life

Finally, there is a "technological" life. That is the period where we consider the AMI system to be fairly modern and possessing most but not necessarily all features and efficiencies of newer systems. PG&E's AMI system could still be used and useful but quickly become technologically obsolete.

Before the introduction of the personal computer it would have been hard to seriously project the impact, and the rate of change, we have seen in that tool on our personal and business lives. We lack the same vision of how metering and communications technology may change over the useful life of the AMI system. PG&E's current metering system with manual meter reading is functional; it also is used and useful, but it is technologically obsolete - once we accept that the proposed AMI technology works. But technological obsolescence alone is not sufficient to warrant replacing the system. That is why we apply an economic test – whether or not the present value of all benefits is greater than the present value of the revenue requirement paid by customers for new system for the useful life of the system. Although PG&E expects the system to remain in service for 20 years, only time will tell whether there will be significant unforeseen developments – good or bad – that may lead to an earlier or later replacement of the AMI system.

[27] Transcript, pp. 1334 – 1335.

8.5. Summary

For this proceeding, we have determined that the AMI communications equipment selected by PG&E will most likely have a useful life of 20 years, and therefore we should use the same 20-year span as the depreciable life until some future depreciation study may justify a different estimated life. Additionally, we find that the cost effectiveness study period should match the useful life of 20 years. Using 20 years will balance the cost-benefit study's results with the likely useful life of the AMI system selected by PG&E.

9. Operating Costs and Benefits

PG&E and DRA now agree on the project installation and deployment costs, and all operational benefits and costs. Although PG&E and DRA stipulated to the operating and maintenance costs (O&M) shown in Table 1, *Stipulated AMI Project Costs*, that table assumes a 15-year depreciable life. This decision adopts a different depreciation life of 20 years for the AMI communications equipment. Therefore, PG&E's actual revenue requirement will be slightly different. The values in Table 1 are adequate for determining whether the AMI project is likely to be cost effective because the revenue requirement impact is not significant when considered against the life of the system and other inherent estimation risks and errors.

TABLE 1
STIPULATED AMI PROJECT COSTS

Line No.	Cost Category	Estimated Costs Deployment (Last Meter Installed in 2011) and O&M (Through 2010) ($ in millions)	PVRR ($ in millions)
1	Project management costs	$87.9	$87.5
2	Risk-based allowance	128.8	135.0
3	Meters and modules	637.4	799.2
4	Network materials	83.6	98.5
5	AMI operations	40.9	119.1
6	Interface and systems integration	94.0	155.6
7	Interval billing system	85.0	109.1
8	Meters/modules installation	326.1	355.9
9	Electric network and WAN installation	87.2	99.1
10	Gas network and other installation	5.8	6.9
11	Meters/modules QA sample testing	2.8	2.3
12	Meter operations costs	22.6	129.3
13	Customer contact-related costs	32.3	45.5
14	Customer exceptions processing	6.6	5.3
15	Marketing and communications	23.1	22.6
16	Customer acquisition	54.8	44.0
17	Other employee related costs	20.7	43.4
18	Total Estimated Project Costs *(totals subject to rounding error)*	$1,739.4	$2,258.3

(Source: Ex. 32, revised Table 10-1 (Revised 3/14/06.)

Table 2, *Stipulated Project Benefits*, excludes the demand response benefits discussed separately in this decision. We adopt the stipulated project benefits as reasonable.

TABLE 2
STIPULATED AMI PROJECT BENEFITS

Line No.	Benefit category	Annualized Benefit After Implementation (2005 $ million)	PVRR ($ in millions)(a)
1	Operational meter reading	$86.2	($1,074.4)(b)
2	Electric Transmission and Distribution	12.8	(195.7)
3	Meter Operations	7.0	(103.4)
4	Customer Contact	2.7	(39.9)
5	Billing Benefits	18.6	(215.3)(b)
6	Gas Transmission and Distribution	1.2	(9.9)
7	Reduced Software License Expense	5.0	(48.1)
8	Remote Turn-On/Shut-Off	11.5	(102.0)(b)
9	Other Employee-Related Costs	16.8	(218.5)
10	Total Annual Benefit	$161.8	($2,007.2)
11	Reduced Equipment Replacement (2011 $)	8.5	(10.2)
12	Deferred Meter Testing	1.6	(6.8)
13	Total One-Time Benefits	$10.1	($17.0)
14	Total Benefits *(totals subject to rounding error)*		($2,024.2)

(a) PVRR values in parentheses are a reduction in revenue requirement.
(b) PVRR totals for these benefits are net of severance costs.
(Source: Ex. 32, revised Table 10-2 (Revised 3/14/06).)

10. Critical Peak Pricing

PG&E's CPP is a voluntary supplemental tariff offered to its residential and small commercial and industrial (C&I) customers with electric demands below 200 kW. The tariff will be available as the AMI modules are deployed and activated. PG&E designed the CPP rate as an "overlay" in addition to the default rate. PG&E intended it to be similar to the rate design used in the Statewide Pricing Pilot (SPP)[28] research project, authorized in D.03-03-036.

28 The SPP was a pricing research project designed to estimate the average impact of time-varying rates on energy use by rate period for residential and small commercial and industrial customers.

Using an overlay maintains the existing inverted-tier rate structure for residential customers with the CPP rate in effect during the summer period (May 1 through October 31). It also preserves Tiers 1 and 2 rate levels protected by Assembly Bill (AB) 1X, and ensures that the rates remain revenue neutral between classes.[29] To maintain revenue neutrality,[30] PG&E applies a CPP rate credit to approximately 95% of the customers' electricity usage during the June 1 through September 30 period. In addition, PG&E applies a CPP customer participation credit to all electricity usage in Tiers 3, 4, and 5 from June 1 to September 30, including critical peak periods in those months, to make the CPP tariff more attractive by providing an opportunity for customers to reduce their bill. PG&E estimates that the target market (residential customers with significant air conditioning loads, with 700 kWh to 1,500 kWh summer monthly usage) would have the opportunity to save 10% or more by reducing their usage by 25% or more during CPP periods. (Ex. 6, p. 1-10.)

PG&E proposes that its CPP rate be in effect for most of the AMI deployment phase and until its subsequent test year 2010 general rate case. (Ex. 6, p. 1-1.) CPP rates and underlying tariffs would be updated annually to maintain revenue neutrality (adjusting for the amount of actual credits so that PG&E fully collects the authorized revenue requirement from within each rate class without inter-class revenue shifting) and recover the CPP participation credit and bill protection costs.

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[29] A portion of AB 1X is codified as Water Code § 80100. "In no case shall the commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, until such time as the department has recovered the costs of power it has procured for the electrical corporation's retail end use customers as provided in this division."

[30] Revenue neutrality means that PG&E has the same opportunity to recover its authorized base margin and reasonable energy procurement costs after implementing the CPP rate design as it did before offering the new tariff option.

PG&E includes a bill protection provision to encourage more customer participation. This provision gives customers the opportunity to test the CPP rate and determine whether the new rate is appropriate for their home or business. Bill protection is provided during a customer's first year (complete summer CPP season) of participating on the CPP rate. At the end of the summer season, PG&E would evaluate each customer's summer season bills and apply a one-time credit to the next bill, if the customer paid more in CPP charges than it received in offsetting CPP credits. PG&E proposes to maintain the one-year bill protection program for newly converted customers for the duration of the AMI deployment. (Ex. 6, p. 1-9.)

PG&E proposes to start with a CPP rate proposal that can be monitored and changed as appropriate. PG&E requests $5 million for measurement and verification research to document the benefits and supporting data for the development and refinement of new demand response rates and programs for customers below 200 kW. We agree with PG&E that it is important to monitor the CPP program effectiveness and understand how customers are responding to the new rate. No party contested the PG&E's request, we therefore adopt it. We direct PG&E to report on the acceptance and degree of success for the CPP rates in the next general rate case.

Dynamic rate offerings for the large commercial and industrial customers are beyond the scope of the AMI proceeding and are addressed separately in A.05-01-016.[31] The following table shows PG&E's proposed CPP rates by customer class.

Table 3
PG&E's Proposed CPP Rates

Customer Class	CPP Rates	Non-CPP Credit	Participation Credit
Residential	$0.60/kWh (2-7pm)	$0.02992/kWh	$0.01/kWh (upper tiers)
Small Light and	$0.75/kWh	$0.02720/kWh	$0.005/kWh

[31] Ex. 6, p. 1-1.

Power	(2-6pm)		(all usage)
Medium Light and Power	$0.75/kWh (2-6pm)	$0.02320/kWh	$0.005/kWh (all usage)

Notes:

1) CPP rates above apply during CPP events which may be called during the period of May 1 through October 31;
2) CPP rates apply during the CPP events;
3) Non-CPP credit is applicable to all usage from June 1st through September 30th outside of CPP events;
4) CPP participation credits are applicable as indicated in the table from June 1st through September 30th, including during CPP events; and
5) Source: Ex. 6, p. 1-16.

DRA's CPP proposal is significantly different than PG&E's. DRA converts the tiers above Tier 2 into Time of Use (TOU) rates with three time periods plus a CPP rate for the summer season. DRA's CPP rate only applies to usage above 130% of baseline in combination with TOU rates. (Ex. 101, p. 3-1.) DRA targets consumption in Tiers 4 and 5 – the highest tiers – where customers have the highest peak usage and therefore the most potential to drop load. DRA believes its rate proposal does not violate Water Code § 80100 by placing all impacts on Tiers 3 and higher, unlike PG&E's proposal that addresses the total bill. DRA also suggests that targeting this smaller group means lower marketing costs. (DRA's Opening Brief, pp. 32 – 32.)

10.1. Discussion

10.1.1. AB1X and Customer Notice

In its comments on the Draft Decision, DRA questions whether the proposed Critical Peak Pricing program is consistent with AB 1X. In particular, DRA questions whether a customer can waive its statutory protections under AB 1X, and whether PG&E's proposed program provides for a knowing waiver of those protections.

Water Code Section 80110 (enacted by AB 1X) provides, in pertinent part:

> In no case shall the commission increase the electricity charges in effect on the date that the act that adds this section becomes effective for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing

> baseline quantities, until such time as [an event that has not yet occurred].

DRA suggests that this language may create a protection that individual consumers cannot waive, and cites County of Riverside v. Superior Court of Riverside County (2002) 27 Cal. 4th 793, 804-805 to support this argument. That case deals with the rights of law enforcement officers under the Public Safety Officers Procedural Bill of Rights Act, and notes that:

> Civil Code section 3513 provides: "Any one may waive the advantage of a law intended solely for his benefit. But a law established for a public reason cannot be contravened by a private agreement." The Bill of Rights Act, which explicitly declares that its purpose is to promote "effective law enforcement" by maintaining "stable employer-employee relations" in law enforcement agencies (Gov. Code, sec. 3301), was clearly "established for a public reason." . . . "[L]abor unrest and work stoppage among police officers pose an obvious threat to the health, safety and welfare of the citizenry . . . ." (27 Cal. 4th at 804.)

In contrast to the public purpose served by the Public Safety Officers Procedural Bill of Rights Act (preventing work stoppages by police officers), we conclude that the purpose of the above-quoted language from AB 1X is to protect individual residential customers from being forced to pay more for electricity usage -- up to 130% of their baseline allowance -- than what they would have paid for the same usage prior to the enactment of AB 1X.. Accordingly, we conclude that individual customers can waive the protections afforded by this provision of AB 1X.[32]

This conclusion is reinforced by the language used in AB 1X. It provides that the Commission shall not increase charges for residential electricity usage up to 130% of the baseline quantity above pre-existing rates. Under the CPP program, the

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[32] Indeed, customers who voluntarily waive their AB 1X protections are *serving* a public purpose by participating in a program designed to decrease peak demands.

Commission is not requiring anyone to pay more for the first 130% of baseline usage than AB 1X allows. The pre-existing tariffs will continue in effect, no customer will be required to switch to the CPP tariff, and customers who do switch to the CPP tariff will be able to opt out of it. Thus, we do not believe that the CPP program violates this language from AB 1X. Rather, we are authorizing a purely voluntary tariff, which exposes those customers who sign up for it to a risk that they may be charged more than the pre-existing rates. Moreover, in return for subjecting themselves to that risk, those customers have a real opportunity to lower their overall electricity bills by changing their consumption patterns.

DRA also argues that in order for there to be a knowing waiver of the AB 1X protections, a customer must be informed of what those protections are. We agree that customers should be informed before they sign up for the CPP program of the AB 1X protections they may be giving up.

Accordingly, when PG&E signs customers up for the CPP program we will require it to provide, along with the other materials it provides customers (e.g.,an application form), a disclosure notice that must include at least the following points:[33]

(1) The CPP tariff is optional. By signing up for the CPP tariff, the customer is waiving protection otherwise afforded by AB 1X. Under AB 1X, a customer cannot be charged more in any month for usage up to 130% of that customer's baseline allowance than the rates in effect prior to February 2001.

(2) There will be "bill protection" for the customer's first full summer season on CPP rates (and any preceding partial season). The notice shall inform customers whether bill protection will apply to customers who opt out of the CPP program before the end of the season.[34] Under

[33] This is not intended to be the precise language to be used in the notice, but only an outline of the points to be covered.

[34] When PG&E files its Advice Letter proposing its electric tariff for the voluntary CPP rates, PG&E shall include a specific proposal on this point (i.e., whether customers who opt out of the CPP program before the end of the season still get bill protection). Any interested person will be able to protest PG&E's proposal.

bill protection, customers will receive a credit after the end of the CPP summer season IF their overall bills for the season were higher than they would have been under the regular tariff. The credit will ensure that the customer does not pay more for electricity overall for the summer season than it would have under the regular tariff. Because customers will not get the benefit of bill protection until the end of the CPP summer season, some (or all) bills during the CPP season may be higher than what the customer otherwise would have been paying on the regular tariff (and some or all may be lower).

(3) After the first full summer season on CPP, there will be no bill protection. Some (or all) bills during the CPP season may be higher than what the customer otherwise would have been paying on the regular tariff (and some or all may be lower). To the extent a customer's bills over the course of the season are higher under the CPP than they otherwise would have been under the regular tariff, the customer will NOT receive an offsetting credit at the end of the season.

(4) A customer may opt out of the CPP tariff at any time. The notice must explain how the customer can opt out.

In addition to the notice provided at the time of sign up, we will require PG&E to provide an additional notice before each customer begins its first CPP season without bill protection. This notice should cover points 1, 2, & 4, above, and also should provide a form for the customer to fill out and return to PG&E if the customer wants to opt out. This notice shall be provided 60 to 90 days before the start of the customer's first CPP summer season without bill protection. In addition, another notice and form must be provided at least once more during the CPP season.[35]

PG&E must consult with the Office of the Public Advisor and obtain that office's approval of the precise language to be used in these notices. In addition, PG&E must consult with the Office of the Public Advisor about the marketing and promotional materials it plans to use in connection with the CPP program. PG&E shall include in

[35] When PG&E files its Advice Letter proposing its electric tariff for the voluntary CPP rates, PG&E shall include a specific proposal on this point (i.e., when this additional notice will go out).

those marketing and promotional materials, such disclosure language as the Office of the Public Advisor may require. The Public Advisor shall require the above four points to be included in such materials to the extent it is practical, and informative, to include those points in the particular material involved.[36]

10.1.2. CPP Issues

PG&E's proposed CPP is consistent with the rates offered in the SPP. We also have more information about customers' acceptance to this type of rate design[37] and the most likely estimated level of demand response.

DRA's CPP rate proposal is significantly more complex because it overlays a TOU rate to the inverted residential rate structure and then adds a CPP rate. We are concerned about the necessity of convincing customers to both participate in a CPP rate and switch full-time to TOU rate with an underlying inverted tier rate structure. Further, we have no record to indicate the likelihood of customers' accepting DRA's proposal for a CPP rate. DRA's proposal may easily discourage customers from switching. The likely key to successful demand response is a clear financial incentive (coupled with an effective informational message) and single focused rate proposal. We therefore will not impose TOU as a requirement for CPP rates.

Neither DRA nor TURN address PG&E's CPP rate proposal for small and medium commercial customers. Also, no party objected to PG&E's proposal to exclude agricultural customers from CPP rates. We will therefore adopt these features of PG&E's CPP proposal, consistent with our adoption of PG&E's residential proposal.

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[36] The nature of the disclosure will need to vary depending on the kind of materials involved: e.g., radio or TV spot; newspaper advertisement; or written material given directly to the customer. Indeed, in the case of a brief broadcast announcement, a simple statement that a customer's monthly bill may be higher than otherwise *may* be sufficient.

[37] Customer Preferences Market Research (CPMR): A Market Assessment of Time-Differentiated Rates Among Residential Customers in California, Momentum Market Intelligence, December 2003.

10.2. Revenue Target

PG&E designed the CPP rates (Table 3) by allocating a summer season revenue responsibility of $45 per kilowatt-year (kW-year), divided by the number of CPP hours. PG&E proposes a maximum of 15 CPP events per summer season with a five-hour duration limit per event (2:00 p.m. and 7:00 p.m.) so there are 75 CPP hours[38] for residential customers and 60 CPP hours for the small C&I customers (four-hour duration limit per event.) PG&E determined the $45/kW-year based on the $52 per kW-year avoided cost of generation (discussed below in Demand Response).

10.3. Critical Peak Pricing Conclusion

We find that PG&E made the most persuasive proposal for a CPP rate design and we will therefore adopt it. PG&E's proposal consists of a CPP proposal available to all residential customers and all small commercial and industrial customers with less than 200 kW demand on a voluntary basis. We are greatly interested in the effectiveness of the CPP tariff, especially during the early years of AMI deployment. Therefore, we will direct PG&E to report annually to DRA and the Energy Division within 60 days of the end of each CPP season the best estimate of demand response achieved during each CPP event, if any, including the number of customers (by class) on the CPP tariff and the participation rate of those customers during CPP events.

11. Demand Response

11.1. Overview

When considering PG&E's AMI deployment we must examine and adopt a forecast of demand response – reduced energy consumption by customers[39] – and we must value that reduction for its contribution to AMI's overall cost effectiveness. As

[38] There are 5 hours between 2 p.m. and 7 p.m. Multiplying 5 hours by 15 events results in a total of 75 hours. (5 x 15 = 75 hours.)

discussed below, we find PG&E presented the most comprehensive and persuasive demand response forecast of 448 MW in 2011 onward (following full-deployment).[40] We find PG&E's range of forecasts for total resource cost benefits to be the most persuasive: a range of $510 million with a $52/kW avoided cost in the base case and $338 million in benefits using an $85/kW avoided cost for Scenario 1(e).[41] We note as discussed below that we will rely on PG&E's avoided cost method for the very limited scope of this proceeding, but in no way does our finding prejudging our pending R.04-04-025[42] where the Commission will adopt a comprehensive policy and method for determining avoided costs.[43] The Commission ordered that it would "… consider any potential revisions to the [adopted interim] methodology in Phase 3 of [the] rulemaking. At that time, we will also consider the potential application of the [adopted interim] methodology to other resource options, such as distributed generation and demand response programs." (D.05-04-024, *mimeo.*, p. 3.) We will do nothing here to otherwise disturb that Rulemaking.

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[39] Demand response impact refers to the change in customer specific peak demand and energy use, by rate period, resulting from time-varying rate.

[40] This forecast applies to both the base case and PG&E's scenario 1(e), as discussed elsewhere in this decision.

[41] Ex. 4-1S, p. 1-2, revised Table 1-1.

[42] See the Rulemaking's December 27, 2005 Scoping Memo: "Recognizing that '[t]he proper valuation of peak load reductions…is needed whether such reductions are achieved through energy efficiency measures, distributed generation or demand response,' [D.05-09-043, p. 141] the Commission directed that consideration of these issues be carefully coordinated and addressed in this generic avoided cost rulemaking." (*Mimeo.*, p. 2.)

[43] Recently in D.05-04-024, dated April 7, 2005 the Commission adopted "… a new avoided cost forecast methodology described in a report prepared by the consulting firm E3. This report, *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs*, (E3 report) [footnote omitted.] and associated spreadsheet models, describe and generate 20-year forecasts of (1) hourly wholesale electricity costs, and (2) monthly wholesale natural gas costs. These wholesale energy cost forecasts represent the total avoided cost of power that a utility would otherwise have to generate or procure in the absence of other resource options like energy efficiency programs." (*Mimeo.*, p. 1.)

11.2. Forecast

PG&E's expected demand response by 2011, with full deployment of AMI and an aggressive marketing campaign, ranges from 206 to 448 MWs for the proposed CPP rate. This estimate is based on estimated price elasticities of demand for the proposed rates which were derived from the econometric energy demand models that were developed in the SPP research project,[44] customer participation level, and customer characteristics (i.e., customer consumption and air conditioning saturation in each zone, etc.). The level of customer participation relies on the customer preference market research[45] (CPMR) results from the SPP and PG&E's customer population characteristics. The CPMR demonstrated that more customers are likely to sign-up for a time-differentiated rate (CPP rate) if there is a significant opportunity to save money on the rate. The research results also showed that acceptance rates increase as customer awareness increase.

PG&E will conduct focused marketing of the CPP rate to customers with the greatest demand response potential. (Ex. 4, pp. 2-2.) This is consistent with PG&E's AMI deployment strategy to begin deployment in the hot inland areas which have the greatest demand response potential. PG&E proposes two phases for its communication and marketing strategy. Phase 1 focuses on AMI deployment introducing the concept of time-differentiated rate options, and educating customers about price responsive behaviors. Phase 2 focuses on customer recruitment and marketing of the CPP program. PG&E requests $18 million in funding for phase 1 for the duration of the AMI project deployment.

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[44] "Impact Evaluation of the California Statewide Pricing Pilot" prepared by Charles River Associates, filed on October 31, 2005, by PG&E, in R. 02-06-001. This report is received into evidence pursuant to Rule 72 and we waive the requirement to file an additional copy in this proceeding.

[45] Customer Preferences Market Research (CPMR): A Market Assessment of Time-Differentiated Rates Among Residential Customers in California, Momentum Market Intelligence, December 2003.

PG&E proposed a voluntary (opt-in) tariff (for residential customers) with a higher rate for CPP periods, a lower rate in non-CPP summer hours, a participation credit for Tiers 3, 4, and 5, and first year bill protection – a guarantee that the customer pays no more under the CPP tariff than under the default rate. PG&E also includes in the program an aggressive CPP marketing campaign to entice and educate customers.

PG&E's CPP rate design provides customers an opportunity to save money by making reasonable reductions in consumption during critical peak periods. The demand response estimates by 2011 are based on an assumption that 35% of residential customers with central air conditioning will participate and 5% of those without air conditioning will participate. (Ex. 4, p. 2-8, Table 2-2, and, attached herein, Table of Demand Response Forecasts and Benefits.) PG&E's estimate also assumes a targeted and aggressive marketing campaign. DRA on the other hand sees these forecasts as overly optimistic and its own optimistic forecast is 30% and its pessimistic forecast is that only 9% will participate. (DRA's Opening Brief, p. 23.)

DRA introduced a study of the experience with a program called "GoodCents" by Florida's Gulf Power. We agree with PG&E's rebuttal testimony that the program is too different to reliably apply to the PG&E situation. For example, GoodCents was focused only the largest-load customers and required that customers have in-home automated energy management systems as well as large electric loads such as pool pumping, electric water and space heating. (Ex. 12-6W, p. 6-2). DRA did not persuade us that the GoodCents program bore a sufficient likeness to PG&E's situation that we should apply any of its experience to this AMI project.

TURN also questioned PG&E's forecasts and proposed significantly lower estimates. TURN asserts that the California Solar Initiative would significantly impact PG&E's targeted reduction of air conditioning load. (Ex. 201, Ch. 3, p. 57.) PG&E responded that the solar installations will not be made by the CPP's targeted population (Transcript p. 306) and TURN applies the full solar target of 176,000 homes in 2001 (AMI's fully-installed date) instead of in 2017 the fully-installed date for solar. TURN compounds this number by annually escalating solar installations after 2011. (Ex. 12, p. 1-5, figure 2-1.) PG&E disagrees with that compounding.

We agree with PG&E that the likely benefits from CPP are different than the solar program benefits. Solar energy tends to displace non-solar generation rather than reduce consumption – it is a form of fuel switching which is comparable to using a hybrid car instead of a gasoline-only car without reducing the miles driven. Here, PG&E forecasts much of the demand response to come from a specific reduction in usage, most especially air conditioning.

PG&E persuasively illustrated this demand reduction effect in Ex. 6: in a hot zone, a moderate-usage residential customer with air conditioning who uses 700 kWh in the summer would have 180 kWh in Tier 3 (beyond the AB-1X fixed rates) and consumption during a critical peak period would likely range from a low of 21 kWh (3% of all consumption) to a high of 42 kWh (6%). If such a customer reduces its load by 25% during the critical peak period, PG&E's proposed rate design would save the customer as much as $12.72 (13.7% of the bill under the default rates) to $2.64 (2.8%).[46] Other examples show that, except for very-high users, customers should generally see a reduced bill. For example, very-high users (1,500 kWh) with 8% of their consumption in a critical peak, and who reduce by 25%, will adversely see a bill increase of $2.80.

[46] Ex. 6, p. 1-11. This is illustrated at PG&E's rate at the time testimony was filed. Actual results on current rates would be slightly different.

Comparison of Demand Response Forecast and Benefits

(Source: PG&E's Opening Brief, Appendix C.)

	Estimates of Demand Response (MW 2011)		Participation Rate Assumptions[1]					Rate Design Assumptions	TRC Value of Demand Response Estimates (20 Year Study Period[2])				
				Residential		Commercial and Industrial (C&I)							
Scenario	Total	Residential	Overall Population 2011	Central Air Conditioning (CAC)	No CAC	A1 Small	Large A1, A6, A10 and E19V	Effective Residential Rate on Critical Peak Price (CPP) Days (Average $/kWh)	Gross TRC Benefits ($Million 2005 PV)	Value of Avoided CT Fixed Cost ($/kW-year)[3]	Planning Reserve Margin	Discount Rate[4]	T&D Benefits ($Million 2005 PV)
PG&E[5]													
Base case (1e)	448	363	15.5%	10% to 35%	5%	2%	2% to 27%	$.73 CPP Peak 2-7pm $.10 Off-peak	$270	$52	15%	7.60%	$68
Low case	206	169	8.2%	5% to 18%	3%	1%	1% to 14%	$.73 CPP Peak 2-7pm $.10 Off-peak	$139	$52	15%	7.60%	$31
TURN													
High	252	165	8.7%	5% to 15%[6]	5%	2%	2% to 27%	$.73 CPP Peak 2-7pm $.10 Off-peak	$110	$23[7]	none[8]	8.68%	none
Low	126	90	5.1%	3% to 9%	3%	1%	1% to 14%	$.73 CPP Peak 2-7pm $.10 Off-peak	$55	$23	none	8.68%	none
DRA													
Optimistic	321	235	13.8%	5% to 30%	5%	2%	2% to 27%	$.445 CPP Peak 2-7pm[9] $.13 Off-peak	$205	$52	15%	8.79%	not provided
Pessimistic	148	71	4.9%	1% to 9%	2%	2%	2% to 24%	$.445 CPP Peak 2-7pm $.13 Off-peak	$89	$52	15%	8.79%	not provided

[1] Participation ranges start in 2006 and ramp up to 2011, after 2011 rates remain flat at 2011 levels.

[2] TURN also presents a 15 year study period case; the 20 year useful economic life of the AMI technology yields an additional residual value that produces the same total value as the 20 year study period.

[3] Ie. Capacity Value. PG&E also provides TRC estimates with an $85/kW-year value resulting in a base case gross TRC benefit of $442 million 2005 PV. $52 is levelized 2008-2027. Both TURN and PG&E project additional benefits from avoided energy costs and T&D losses which are not shown in this column.

[4] PG&E uses a discount rate that includes an after-tax cost of debt. TURN and DRA use a discount rate that includes a before-tax cost of debt.

[5] PG&E estimates are October 2005 values with a revised deployment schedule as reflected in Exhibit 4-1S. The difference between October and June is minimal with June base case estimates of 455 MW and $279 million Gross TRC ($52/kW year avoided capacity).

[6] TURN reduces the residential air conditioning segment by approximately 50% prior to applying a participation rate. The table shows effective rates for the total segment.

[7] $23 is a levelized 2008-2027 value.

[8] PG&E estimates elimination of the 15% planning reserve margin results in a $7/kW-year reduction in TURN's avoided generation cost vs TURN's ancillary service benefit.

[9] DRA's rate design for residential eliminates the usage in Tier 1 and Tier 2 from any rate change resulting in lower average effective CPP hour rates, and higher effective off-peak hour rates. The lower off-peak to on-peak ratio results in over 25% less demand response impact per residential customer. DRA's MW estimates with PG&E rates are 404 MW for the optimistic scenario, with 317 MW from the residential segment.

11.3. Demand Response Conclusion

We believe that PG&E conducted a comprehensive study of demand response using the statistical model developed in the SPP. With the aggressive and comprehensive educational advertising component in PG&E's CPP proposal, the customer participation level is likely to achieve the levels supported by PG&E's testimony. This CPP rate is a precursor of more accurate and timely rate designs that will be possible following the full implementation of AMI. A voluntary program will allow PG&E to build trust with the first eligible customers (those with AMI deployed) and subsequent rate design proceedings can build on the experience we derive from the voluntary CPP as we achieve full deployment. We have no record to consider either a mandatory or an opt-out program at this time.

Deployment is geared to the hotter climate zones first – those customers will have the greater potential and we hope the greater willingness to participate in a demand response program as PG&E builds-out the system. According to PG&E's witness, the bill protection and the customer's ability to opt-out after the first year are critical inducements to successfully sell this rate proposal[47] – otherwise DRA and TURN's more dismal forecasts could be realized. We noted already the multi-year duration of the deployment: so not all customers will have the CPP available to them for the summer in 2007, or even for several more years until their neighborhood is converted and switched over to the AMI system. As a result, the demand response contributions will grow dramatically each year until all AMI modules are installed.

We find PG&E's forecast for the range of likely customer responses and the impact of its CPP to be credible and persuasive. We will adopt PG&E's forecast and use it to evaluate the cost-effectiveness of AMI.

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[47] Ex. 4, p. 3-15.

12. Avoided Cost

We need to adopt three factors in order to correctly value the avoided generation costs of the demand response: capacity cost, energy cost and the appropriate discount rate. PG&E and DRA agree on the first two but diverge sharply on discount rates. TURN disputes all three components with PG&E. As discussed below, we will adopt PG&E's calculations for all three factors. As noted above, our finding on avoided capacity cost applies in the limited application of valuing the AMI demand response: avoided capacity costs are to be considered for specific purposes when timely decisions are needed. We do not otherwise prejudge our pending rulemaking.

PG&E proposes a supply-side avoided capacity cost of $52 per kW year, based on the Commission's 2004 Market Price Referent.[48] PG&E claims this is consistent with its other avoided generation costs testimony in recent Commission cases.[49] PG&E also used an avoided capacity cost of $85 per kW year, as directed by the July 21, 2004 Assigned Commissioner's Ruling, and intended this to be consistent with avoided costs used for demand response in the past. PG&E used $52 per kW year and the $85 per kW year avoided capacity costs scenario 1(e) and the base case respectively.[50] For the base case, the gross Total Resource Cost benefits are $510 million in Revised Table 1-1 (in 2005 Present Value). For Scenario 1(e) the benefits are $338 million. (Ex. 4-1S, Revised Table 1-1.) Either value more than offsets the operational benefit shortfall calculated after considering the stipulations between PG&E and DRA, whereby the forecast operational gap was reduced to $234 million. (Revised Tables 10-1 and 10-2, Ex. 32.)

DRA supports PG&E's use of $52 per kW year and believes any further litigation here would only duplicate the Rulemaking. (DRA Opening Brief, p. 24.)

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[48] Energy Division Revised 2004 Market Price Referent, dated February 10, 2005, adopted in Resolution E-3942.

[49] Ex. 12, Ch. 3 p. 3-2.

[50] Ex. 4-1S, p. 1-2, Revised Table 1-1.

PG&E and DRA had a methodological dispute over the recognition of the tax deductibility of interest when calculating the net present value of the AMI projects cost and benefits. PG&E was persuasive that the AMI project is cost effective whether the tax benefit of the deductibility of interest is reflected in the discount rate (7.60% the after-tax weighted cost of capital) or in the annual cash flows discounted by the pre-tax rate of return (8.79%).[51] PG&E's method used an after-tax project cash flow and therefore used an after-tax discount rate. We find PG&E was internally consistent in its method and therefore will not adjust the discount rate.

There is a significant difference between PG&E's $52 per kW year and TURN's $23 per kW year which is caused by using different gross fixed costs for combustion turbines. As already noted, PG&E's cost assumptions come from the Commission's adopted Market Price Referent. TURN instead used JBS Energy, Inc.'s fixed charge model to compute the combustion turbine fixed costs. TURN also uses a constant hourly gas price. PG&E argues, and we agree, that TURN's calculations are not reasonable. TURN did not show its approach to be more consistent than PG&E's with existing Commission policy on avoided cost determination.

12.1. Conclusion

We will adopt the Scenario 1(e) forecast of $52 per kW and a benefit calculation of $338 million to evaluate the AMI deployment. This is more conservative than the Base Case analysis and still results in finding that the project is cost-effective. We adopt PG&E's after-tax calculation of cash flow and the use of an after-tax rate of return as the discount rate.

[51] Ex. 11, Ch. 14, p. 14-6.

13. Ratemaking

13.1. Test Year 2010

PG&E's pending general rate case is for test year 2007 and it excludes consideration of deploying AMI. The next triennial proceeding would therefore have a test year of 2010, which is one year before the earliest AMI full deployment in 2011. PG&E's next rate case will only have incomplete AMI data and clearly declining/short-lived costs for the incumbent metering system. Therefore, we put PG&E on notice that it must present as one option in the next general rate case the continuation of the balancing accounts and benefit guarantee adopted herein (appropriately escalated and adjusted) for the duration of the 2010 – 2012 rate cycle. In this way we can consider whether there is sufficient data to allow a reasonable forecast for AMI in test year 2010 or whether we should defer total integration of the AMI system into test year 2013.

13.2. Balancing Accounts

PG&E proposes separate balancing accounts for the gas and electric departments. The balancing accounts will record the revenue requirement on an actual cost basis as AMI deployment occurs with an offset of the per-meter benefits as adopted here.[52] In this way no costs are recovered in PG&E's revenue requirement before the AMI modules are installed and a complete billing route is converted. Based on the number of conversions, PG&E will offset the new revenue requirement by the per meter operational savings. (This avoids an inaccurate forecast of cost reductions in the pending rate case.) The demand response benefits are reflected indirectly through reduced procurement costs as demand response reduces critical peak consumption and are not recorded in the

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[52] PG&E would record (1) actual AMI Project revenues from rates set in this proceeding as a credit to the account; (2) actual capital-related revenue requirements calculated on actual recorded plant additions as a debit to the account; (3) actual O&M expense as a debit to the account; (4) per meter forecast benefits as a credit to the account based on the number of meters activated and the meeting of other project milestones; and (5) interest calculated monthly based on the average account balance for the month. (Ex. 5, Ch. 2, p. 2-5.)

balancing accounts. DRA agreed with the proposal. We find PG&E's proposed balancing account mechanism, with a per meter benefit credit, to be reasonable because PG&E recovers its new AMI-related costs on an actual basis and it ensures ratepayer benefits are captured as meters are activated. We also allow, as an exception, that PG&E may record the costs of new construction pre-deployed AMI modules at the time of installation, as discussed elsewhere.

13.3. Operational Benefits Calculation

Most of the operational benefits identified by PG&E occur as AMI communications modules and other AMI equipment are activated and eliminate the need for manual metering reading. For both electric and gas, PG&E forecast operational benefits in the first four years of the project, and calculated the forecast operational benefits per activated meter per month. The operational benefits per activated meter per month are $1.7722/per meter per month for electric and $1.0366 for gas.[53] DRA and PG&E now agree on the operating costs and operating benefits and we will adopt these monthly benefit per-meter rates for the gas and electric departments. TURN does not oppose these figures, but it expresses concern that it "will be very difficult to tease out in future rate cases whether the benefits forecast today actually materialize." (Opening Brief, p. 62.) TURN therefore prefers its amortization method discussed below.

13.4. TURN's Proposed Amortization

The convention of this Commission is that long-lived assets added to rate base are depreciated over their useful life. (See the earlier discussion.) As depreciation accrues annually, the accumulated depreciation is a reduction to the rate base value used to calculate the cost of debt and equity recovered in the authorized rate of return. For example, an asset that originally cost $10,000, and four years later, has $2,000 in accumulated depreciation would have a net rate base value of $8,000. If the authorized

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[53] Ex. 11, Ch. 15, Attachment 1.

rate of return on rate base is 12%, the return on investment to cover debt and equity would be $960.[54]

In this simple example, revenue requirement is the depreciation expense and return plus other operating costs and taxes. In the next year, if there has been another $500 of deprecation, rate base is reduced to $7,500 and the return is reduced to $900. Thus, with no other changes, rates would actually go down to reflect the $60 decrease in revenue requirement. In this example – the normal method used by the Commission - depreciation is a constant $500 for the life of the asset ($10,000 divided by 20 years). In the final 20th year of asset-life, the last amount of net rate base would be $500, with a 12% return of $60 included in revenue requirement. Thus the revenue requirement declines over the life of the asset.

Although there is a new rate base investment for AMI to be recovered from ratepayers in its revenue requirement, PG&E also captures the recovery of operational benefits in the early years in the balancing accounts as a per-meter offset. PG&E proposes in its next general rate case to adjust the operating and maintenance expense forecasts downward for the avoided or reduced operating costs that result from deploying the AMI. Once the test year revenue requirement is correctly forecast, PG&E would discontinue the balancing accounts including per-meter benefit offset.

TURN proposed an alternative recovery – a levelized fixed amortization -like a conventional home mortgage or car loan. Beyond using a constant mortgage style amortization instead of a declining rate base, TURN also proposes that the Commission should capture the full present value of all forecast operational benefits to be offset against the AMI costs.[55] The original cost and interest net of lifetime operating benefits would be recovered by a constant or fixed amount - assuming the rate of return on rate

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[54] $8,000 x 12% = $960 - this is a simplified after-tax illustration.

[55] Ex. 201, p. 36-38.

base remained constant. TURN argues that the actual future benefits are so uncertain that its proposal is the only way to ensure ratepayers see a defined amount of benefit.[56] This shifts the risk for any greater or lesser actual benefits entirely onto PG&E's shareholders for the life of the AMI system.

We are not persuaded by TURN that such a method is reasonable for either ratepayers or shareholders. PG&E focuses on the downside risk to shareholders and raises a plausible argument that some project costs could be subject to write-off for financial reporting purposes if their recovery is deferred or is uncertain.[57] We need not go that far here and address the possibility of an impaired asset. We believe that the current cost of service rate setting regime gives us ample opportunity to seek out and to capture all operational cost savings that will result over the life of the AMI system in subsequent rate proceedings. We are not persuaded by TURN to alter our cost recovery methods. Nor are we persuaded that we should capture the forecast present value of all future savings at this time. We believe that there are other benefits that will emerge from AMI deployment that are not yet identified or implemented.

14. Societal Benefits

DRA raised an issue that PG&E only addressed (1) operational costs and benefits and (2) demand response benefits, but it did not include in this proceeding a value for certain societal benefits that would result from AMI. DRA states that "societal benefits are benefits that probably do not lower the utilities' costs directly." (DRA's Opening Brief, p. 9.) DRA presented several examples: at least two examples should be mentioned now. DRA suggests voltage reduction can occur, based on AMI-derived system data, which could lead to cost reductions. Secondly, DRA suggests there is a

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[56] "The only way to ensure that today's ratepayers do not end up subsidizing a project based on benefits that fail to materialize is to more evenly spread out the costs and benefits over time." Opening Brief, p. 55.

[57] TURN's Opening Brief, p. 82.

potential to reduce the frequency and duration of outages with better information about the current status of the distribution system.

No party disputes societal benefits such as these and others are likely to occur with an AMI deployment, but no one offers a persuasive "hard" value for these benefits to consider in the economic evaluation of AMI. We will therefore acknowledge our expectation of societal benefits but we will not rely on their existence to justify the deployment of AMI. There are sufficient probable operating and demand response benefits to justify deployment.

Additionally, PG&E is agreeable to a DRA proposal to conduct a feasibility analysis of voltage reduction based on AMI-gathered data, although PG&E's testimony indicates various concerns about the practicality of using AMI to regulate voltage. PG&E has indicated that it will work with the AMI system vendors to determine the technical feasibility and costs associated with the use of AMI for voltage reduction. PG&E offers that that if it is reasonable to use AMI voltage measurements to help regulate circuit voltage, then it will collect information on using AMI data to analyze and manage circuit voltage and it will provide a report on these matters in its next general rate case. DRA indicated that PG&E's study proposal is acceptable.[58]

14.1. Customer Access to Data

PG&E proposes to provide reasonable immediate data access to customers and to promptly develop data access structures based on the needs of customers and other stakeholders. PG&E suggests: web (internet) access for all customers to their data up through the previous day; real-time data access devices for customers over 200 kW; offering customers and their energy service providers access to all accounts with a single log-in to be phased in during the first part of the project; and an Automated Data Exchange proposal to be developed and presented to the Commission within 180 days of

[58] Opening Brief, p. 63, and referencing Ex. 11, p. 20-1.

setting the first AMI meter along with a request for additional funding; and additional PG&E also proposes that it should develop data access structures later, at incremental cost, once the needs of other stakeholders are understood. (PG&E's Opening Brief, pp. 62 – 63.) This comports closely with recommendations by SPURR. (Ex. 401.)

SPURR, SVLG and eMeter filed an opening brief as Joint Parties. These parties propose that PG&E should promptly file an advice letter to implement a tariff for customer access to its detailed account data. They also propose that PG&E should promptly implement an Automated Data Exchange proposal to address SPURR's recommendation that customer data be available to qualified third parties at the same time and on the same terms provided to PG&E's internal departments.

The Joint Parties propose hourly and daily electricity and gas usage data collected via the AMI network should be posted to a data server in an open format immediately following retrieval and any necessary pre-processing. This will allow any qualified (not yet defined) party to retrieve the data automatically over the internet using an automated software process. They suggest two key principles: (1) the data is accessible to customers and to qualified parties at the same time as PG&E's Information Technology systems gain access to the data and (2) qualified party access may be authorized either electronically or by a paper authorization with "wet" signature from the customer. This embryonic proposal, suggested by the Joint Parties, should be further developed by PG&E, the Joint Parties, and any other interested parties and they also propose that this data access system should be filed and approved, by the Commission's informal advice letter process by an advice letter to be filed within 180 days of this decision. (Joint Parties' Opening Brief, pp. 4 – 5.)

We agree in large part that all customers should have prompt access to their own data. But we have no record here, and the advice letter process is too limited to allow the development of an adequate record whereby we might grant third parties access to customer data and create a public interface with PG&E's data systems. An advice letter is also an improper procedure to adopt funding for such a project. We will require PG&E

to file an application, with appropriate supporting testimony and underlying work papers to support its proposal, including cost recovery. We will not impose a 180-day deadline from the first meter installation – deployment will take time and the data access interface needs to safeguard customer privacy and further it must also safeguard PG&E's operating data from unnecessary access or damage.

We will further require that prior to filing the application PG&E, conduct only publicly noticed open workshop discussions and that no party or sub-group of parties has greater access than any other stakeholder in the process. We expect and encourage DRA to actively participate, and as necessary, to involve any other staff division (e.g., Energy Division, Public Advisor) that can provide additional advice or input on consumer privacy, or any other relevant issue. We are concerned with protecting both the nascent competition in customer-side-of-the-meter services or products and safeguarding consumer privacy. SPURR's testimony recognized the need to ensure no "undue preference" for PG&E's internal service offerings to those of third-party providers that SPURR may otherwise prefer. (Ex. 401, p. 5.) We agree and will go further to protect all consumers from unwarranted intrusions.

We are also concerned about the cost impact on smaller customers, so we believe that PG&E must focus on providing the lowest cost or even no cost (especially no tariff rate or charge) for the most basic of timely access for residential consumers. Any program feature likely to increase the cost of the system should be focused on the larger customers who are most likely to use and benefit, and therefore should pay for enhanced program features. For the sole purpose of providing individual customers day-after free web access to their own billing data, we will allow PG&E to file an advice letter as soon as possible. No third-party access, aggregation of data, or any funding request, should be included in this limited proposal.

We direct PG&E to conduct an open workshop process and then file a ratesetting application in not less than 180 days and no later than one year from the effective date of this decision.

14.2. Flexible Billing Dates

SPURR proposes that PG&E accommodate customer requests (including requests by third-party energy service providers who provide commodity service) to have selected meters read on a single day in each calendar month. PG&E indicated it will try to accommodate these requests for specific meter reading and billing periods, "subject to various capacity constraints in the measurement, billing, and collection processes." (PG&E Brief, p. 64.) PG&E states it has a limited capacity to do this. PG&E processes an average of 260,000 bills per day and points out that changing metering or billing periods could cause PG&E to incur additional costs. Therefore, we direct PG&E to ensure that all incremental costs are borne solely by those customers or energy service providers who request this special service. PG&E must file a new tariff charge by advice letter to establish this service and recover these costs. This tariff offering is much smaller and therefore more reasonable for an advice letter than the proposal for real-time billing access previously discussed.

14.3. Periodic Assessment of Technology, Performance, and Customer Demand for Information

While we recognize that PG&E's AMI deployment meets our functionality requirements as set forth, new technology may emerge that offers PG&E and its customers increased reliability and performance enhancements. We expect PG&E to monitor market place developments so, whenever feasible, it can upgrade its AMI system and offer its customers technology upgrades. To enable us to keep abreast of the AMI program, we will require PG&E to provide us with semi-annual assessments of advancements in relevant technology and its AMI deployment, beginning six months after the adoption of this decision. PG&E shall provide this assessment to the Commission's Energy Division, DRA and other parties in this proceeding. These assessments should include general information on advances in metering technology and infrastructure with specific information, when available, on (1) meter/meter module reliability, (2) meter/meter module costs and performance, and (3) movement or adoption of open architecture standards for automated meters.

Through this process, the Commission intends to monitor PG&E's AMI system performance. PG&E's semi-annual assessments must address both system performance and system cost effectiveness. Within 180 days, PG&E is required to establish performance criteria in consultation with the Commission's Energy Division and DRA that can be used by PG&E to monitor and periodically evaluate its system implementation. At PG&E's first semi-annual assessment, PGE should self assess its AMI system based on these performance criteria. We also expect PG&E to continuously review and evaluate its system cost effectiveness – identifying costs and benefits realized versus those projected in the utility's AMI project application as approved. The semi-annual assessments should include PG&E's updated cost effectiveness review. In the future, the Commission may consider incentive mechanisms to encourage PG&E to improve the performance and cost effectiveness of its AMI project.

It is our desire to ensure that both customers and PG&E gain the full benefits of AMI deployment—particularly with the rollout of demand response tools such as time-varying rates. PG&E should also be encouraged to continue to experiment with its own information systems and information services, and regularly reassess customer demand for real-time energy usage information. Therefore, PG&E's semi-annual assessment should examine (1) the ability to provide real-time usage / pricing information to customers and (2) customer interest in accessing real-time usage / pricing. PG&E shall stringently safeguard customer privacy information and protect any market sensitive operating data as needed.

In addition to the semi-annual assessment, PG&E should conduct an annual workshop in conjunction with the California Energy Commission to provide the vendor and intervener community with an opportunity to observe and comment on PG&E's AMI assessment.

14.4. Conclusion

As discussed above we will adopt the gas and electric balancing accounts proposed by PG&E. We will adopt PG&E's calculation of per-meter monthly benefits: $1.7722/per meter-month for electric and $1.0366 for gas. We will allow new construction pre-deployment costs in the balancing account at the time of installation and benefits to accrue at the time the new construction territory is converted to the AMI network. We direct PG&E to aggressively pursue all operating and societal benefits and to provide detailed testimony in the next general rate case reporting on the maximum potential for all such benefits.

15. Environmental Review

There is no need for an analysis of PG&E's AMI deployment pursuant to the requirements of the California Environmental Quality Act (CEQA). The AMI deployment falls within the exceptions found in either or both CEQA Guideline § 15301(b), for existing facilities of public utilities, and § 15302(c) for the replacement or reconstruction of existing utility systems and/or facilities involving negligible or no expansion of capacity. Therefore, the Commission is under no legal obligation to undertake any environmental review before approving this application.

16. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Douglas M. Long is the assigned ALJ in this proceeding.

17. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure.

Comments were filed by DRA, PG&E, TURN, and SSJID On July 5, 2006, and reply comments were filed by TURN and PG&E on July 10, 2006. To the extent changes were necessary as a result of the filed comments, they were made in the body of this order.

Findings of Fact

1. PG&E selected DCSI to provide a Power Line Carrier technology for electric meters and Hexagram, Inc. to provide a fixed network system with radio frequency communication channels owned by PG&E for gas meters. The selection was based on a review of proposals following a detailed request for proposals.

2. The proposed systems meet the Commission's functional criteria for AMI, except that the electric communications system is not an open architecture system. DSCI's system does not create a bottleneck blocking other communications over the electric distribution network. PG&E's contract with DCSI provides for a commercially viable licensing of the technology.

3. PG&E has implemented a project management structure that will provide adequate oversight by senior managers. The proposed stipulation will provide DRA and the Commission's Energy Division the same data available to the Executive Steering Committee that is relevant to monitor project deployment.

4. PG&E and DRA included a provision in a stipulation that might excuse PG&E's actions due to a "transportation accident."

5. PG&E and DRA included a provision in a stipulation that might excuse PG&E's actions during a "labor disputes" with its own workforce.

6. PG&E can evaluate, and when feasible, accelerate the deployment of AMI technology by installing the communications network in new construction if and when there are likely savings by eliminating subsequent up-grades from non-AMI equipped meters to AMI equipped meters.

7. PG&E can avoid unnecessary costs if it defers installing AMI in the territory where the County of Yolo and Cities of Davis, West Sacramento, and Woodland (Yolo/Cities) have contested pending condemnation proceedings. A deferral avoids installing communication modules that may not be used by a new service provider that

acquires PG&E service territory and displaces PG&E as the incumbent utility. Installing unnecessary AMI components otherwise raises the cost of compensating PG&E for the acquired territory.

8. The project costs, as stipulated (see Table 1), are reasonable and within the range of a likely litigated outcome. They include a risk based allowance for unforeseen events. PG&E has a system in place to control and authorize the use of the risk based allowance.

9. The stipulation for cost overruns in excess of the adopted budget will share overruns between ratepayers and shareholders. The stipulation provides that PG&E's shareholders will absorb 10% of up to $100 million without a further reasonableness review. The 10% share provides PG&E an incentive to control cost overruns.

10. The useful life of the AMI modules is 20 years. The appropriate depreciation life is 20 years, the same as the useful life.

11. The avoided costs for demand response are reasonably forecast to be $52 per kW year, using PG&E's recommended method of calculation. We can use this method and its results to evaluate the cost effectiveness of the AMI project in this proceeding without prejudicing the outcome in Avoided Cost Rulemaking 04-04-025.

12. The advertising campaign for CPP is reasonably designed and necessary to inform and attract voluntary customers likely to provide the expected demand reductions during critical peak periods.

13. The project benefits, as stipulated (see Table 2), are reasonable and within the range of a likely litigated outcome.

14. A voluntary critical peak pricing tariff for residential and small commercial or industrial customers with under 200 kW demand will provide PG&E with up to 15 critical peak events per summer season for customers to reduce their load in exchange for an incentive pricing option. Certain customers, primarily those with significant air conditioning load, can reduce their total bill by up to 10% in exchange for a 25% reduction in their load just during the critical peak periods. Other customers can benefit too.

15. A bill guarantee, limiting the CPP customer's accumulated bills for the six month CPP season to the total amount otherwise payable under the customer's default rate, provides a participation incentive through a customer's first full summer on the CPP tariff.

16. The demand response benefits from PG&E's proposed CPP will provide positive benefits contributing to the AMI's overall cost effectiveness.

17. Balancing accounts will allow PG&E a reasonable opportunity to recover operating and capital costs as the AMI modules are deployed and put into service. The balancing accounts will also ensure customers receive an offsetting allowance for cost savings as PG&E's operating costs are reduced.

18. AMI will not be fully deployed before PG&E's next general rate case which is scheduled to have a test year 2010. It is beneficial to ratepayers if the Commission considers as an option to continue the balancing accounts in a test year 2010 forecast that omits AMI implementation.

19. The reasonable forecast of operational benefits per activated meter per month are $1.7722/per meter-month for electric and $1.0366 for gas.

20. Conventional rate base amortization of capital costs and annual recovery of operational costs, net of operational benefits, reasonably recovers AMI costs and benefits. Costs and benefits can be reviewed and adjusted in subsequent general rate cases.

21. TURN's proposed levelized fixed amortization of lifetime project costs and benefits is not a reasonable alternative.

22. Various societal benefits are likely to accrue as additional benefits from AMI deployment, but they are not quantifiable for cost recovery or necessary to determine that AMI is cost effective.

23. Customers need reasonable access to their energy consumption data. No cost or low cost web-based options are appropriate for small customers.

24. PG&E can examine the possibility of allowing customers or energy service providers to have flexible billing dates. A new tariff for this service will ensure that any incremental costs are borne only by those who use the service.

25. The AMI deployment is not a project subject to CEQA.

Conclusions of Law

1. PG&E met its burden of proof and, with the other parties, presented sufficient credible evidence to find that it is reasonable to authorize PG&E to deploy the AMI project as modified in this decision.

2. It is reasonable to affirm the ALJ determinations on confidential exhibits, transcripts and briefs.

3. There is sufficient credible evidence to adopt as reasonable a project budget of $1.7394 billion, inclusive of a Risk Based Allowance, or contingency, of $128.8 million and $49 million for pre-deployment costs approved in D.05-09-044.

4. It is reasonable to adopt a 20-year life depreciation schedule for the AMI communications module components based upon the system's expected 20-year useful life.

5. It is reasonable to adopt a 10% shareholder and 90% ratepayer risk sharing of cost overruns, not to exceed $100 million beyond the total project costs of $1.6846 billion, and only conduct a post-fact reasonableness review of any costs in excess of $1.7846 billion.

6. The cost overrun stipulation should be modified to clarify that "transportation accidents" can only be included in force-majeure when PG&E can demonstrate that it was neither intentionally nor negligently responsible for any transportation accident-related delays to the project.

7. The cost overrun stipulation should be modified to exclude from force-majeure "strikes or other labor disturbances" as a provision that might excuse PG&E's actions during a labor dispute with its own workforce or its vendors or contractors.

8. The proposed balancing accounts provide and fair and reasonable means for PG&E to recover the costs of deploying AMI and offset existing rates for the forecast operational savings.

9. PG&E's critical peak pricing rate design is a just and reasonable rate to provide economic incentives for ratepayers to participate in a demand reduction program.

10. A voluntary critical peak pricing rate design does not violated Water Code § 80110, provided that the customer receives adequate notice that by signing up for the program the customer waives certain otherwise applicable statutory protections contained in § 80110.

11. It is reasonable to require PG&E to provide notice to customers, in consultation with the Office of Public Advisor, to inform customers that they waive certain statutory rights contained in § 80110 by signing up for the program.

12. CPP rates will provide demand response benefits.

13. There was sufficient credible evidence demonstrating that PG&E's proposed AMI is likely to be cost effective over its useful life.

14. PG&E should defer installing AMI in the territory where the County of Yolo and Cities of Davis, West Sacramento, and Woodland (Yolo/Cities) have contested pending condemnation proceedings to acquire PG&E service territory and displace PG&E as the incumbent utility. This deferral avoids installing communication modules that may not be used by a new service provider and would otherwise raise the cost of compensating PG&E for the acquired territory.

15. PG&E should collect data on voltage measurements to determine if it is feasible to regulate circuit voltage with its AMI infrastructure. PG&E should provide a report on these matters in its next general rate case.

16. PG&E should provide free web access to day-after data for individual customers.

17. Prior to offering more complex real-time access to customer data, PG&E should conduct publicly noticed workshops to consider an automated data exchange. PG&E

should file an application to create an adequate record and fairly assign any costs for such a service.

18. PG&E should ensure that all incremental costs for flexible meter reading are borne by those customers that use the service.

19. AMI deployment is not a "project" as defined by § 15378(a). Therefore, no CEQA review is necessary.

FINAL ORDER

IT IS ORDERED that:

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.

3. PG&E shall include in its compliance advice letter an electric tariff for a voluntary Critical Peak Pricing (CPP) rates, as modified and adopted by this decision, for residential customers and for its small commercial and industrial customers with peak demand of less than 200 kW. The compliance advice letter shall include PG&E's proposal regarding bill protection for customers who opt-out of the CPP program before the end of the bill protection period.

4. PG&E shall provide the Division of Ratepayer Advocates (DRA) and the Energy Division a regular summary report of the following information as is provided to PG&E's Executive Steering Committee on the status of the Project: (1) Project status; (2) Progress against baseline schedule including equipment installation and key

milestones; (3) Actual Project spending vs. forecast; and (4) Risk-based contingency allowance draw-down status. Unless more frequent reports are necessary, these shall be monthly.

5. PG&E shall report to DRA and the Energy Division within 60 days of the end of each CPP season the best estimate of demand response achieved during each CPP event, if any, including the number of customers (by class) on the CPP tariff and the participation rate of those customers during CPP events.

6. PG&E shall provide disclosure notices about specific provisions of the CPP program, as described in Section 10.1.1. PG&E must consult with the Office of the Public Advisor and obtain that office's approval of the precise language to be used in these notices. In addition, PG&E must consult with the Office of the Public Advisor about the marketing and promotional materials it plans to use in connection with the CPP program. PG&E shall include in those marketing and promotional materials such disclosure language as the Office of the Public Advisor may require.

7. PG&E may not deploy AMI technology in the territories where the County of Yolo and Cities of Davis, West Sacramento, and Woodland (Yolo/Cities) while there are pending condemnation proceedings to acquire PG&E service territory and displace PG&E as the incumbent utility. PG&E may not install AMI components if the November 2006 election approves annexation without a further order of this Commission. If the annexation election fails, PG&E may not install AMI components until any legal challenge of the election is final.

8. PG&E shall evaluate and then accelerate the deployment of AMI technology by installing the communications network in new construction whenever there are savings by eliminating subsequent up-grades from non-AMI equipped meters to AMI equipped meters. PG&E shall timely record the costs of early deployment in the balancing accounts and shall recognize the per-meter benefits after the AMI modules are activated.

9. The cost overruns stipulation is modified to clarify the "force-majeure" provisions that "transportation accidents" can only be included in force-majeure when PG&E can

demonstrate that it was neither intentionally nor negligently responsible for any transportation accident-related delays to the project.

10. The cost overruns stipulation is modified to exclude from "force-majeure" provisions "strikes or other labor disturbances" as a provision that might excuse PG&E's actions during a labor dispute with its own workforce or its vendors or contractors with respect to the cost overrun stipulation.

11. PG&E must file by advice letter a new tariff provision to provide free web-access for individual customers to have access to day-after consumption data.

12. PG&E shall conduct publicly noticed open workshops prior to filing an application for authority to implement an Automated Data Exchange to allow customers and customer-authorized third parties access to detailed account data. PG&E shall file the Automated Data Exchange application in not less than 180 days from the effective date of this decision.

13. PG&E shall collect data on voltage measurements to determine if it is feasible to regulate circuit voltage with its AMI infrastructure. PG&E shall provide testimony on these matters in its next general rate case.

14. PG&E shall serve testimony in its next general rate case to report on its evaluation of customer acceptance, and measurements of the level of participation, for the CPP rates adopted herein.

15. PG&E shall serve testimony in its next general rate case to present as an option, continuing for the rate case cycle, the balancing accounts and cost savings benefits as adopted herein (appropriately escalated and adjusted). This testimony shall present an alternative to forecasting the full impact on the test year of the ongoing AMI deployment.

16. PG&E shall provide the Chief Administrative Law Judge, Energy Division, DRA and all other parties in this proceeding a semi-annual report assessing AMI deployment as set forth herein, beginning six months after the effective date of this decision.

17. PG&E shall conduct an annual workshop in conjunction with the California Energy Commission as described herein.

18. Application 05-06-028 is closed.

This order is effective today.

Dated July 20, 2006, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

I reserve the right to file a concurrence.

/s/ JOHN A. BOHN
Commissioner

APPENDIX A

LIST OF APPEARANCES

Kevin Golden
Attorney At Law
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., SUITE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
kgolden@adamsbroadwell.com
For: CUE - Coalition of California Utility Employee

James Weil
AGLET CONSUMER ALLIANCE
PO BOX 37
COOL CA 95614
(530) 885-5252
jweil@aglet.org
For: Aglet Consumer Alliance

Paul Angelopulo
Legal Division
RM. 5031
505 VAN NESS AVE
San Francisco CA 94102
(415) 703-4742
pfa@cpuc.ca.gov
For: ORA

Michael E. Boyd
President
CALIFORNIANS FOR RENEWABLE ENERGY, INC.
5439 SOQUEL DRIVE
SOQUEL CA 95073
(408) 891-9677
michaelboyd@sbcglobal.net
For: Californias for Renewable Energy, Inc.

Jeffrey P. Gray
Attorney At Law
DAVIS WRIGHT TREMAINE, LLP
ONE EMBARCADERO CENTER, SUITE 600
SAN FRANCISCO CA 94111
(415) 276-6581
jeffgray@dwt.com
For: South San Joaquin Irrigation District

Chris King
EMETER STRATEGIC CONSULTING
1 TWIN DOLPHIN DRIVE
REDWOOD CITY CA 94065
(650) 631-7230
chris@emeter.com
For: EMETER CORPORATION

Michael Rochman
SPURR
1430 WILLOW PASS ROAD, SUITE 240

William B. Marcus
JBS ENERGY, INC.
311 D STREET, SUITE A
WEST SACRAMENTO CA 95605
(916) 372-0534
bill@jbsenergy.com.
For: Yolo County and Cities of Davis, West Sacramento and Woodland

Scott H. Debroff
Attorney At Law
LEBOEUF, LAMB, GREENE & MACRAE, LLP
200 NORTH THIRD STREET, SUITE 300
HARRISBURG PA 17108-2105
(717) 232-6453
sdebroff@llgm.com
For: Hunt Technologies, Inc.; Cellnet Technology, Inc.

J. Michael Reidenbach
Attorney At Law
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442, MAIL CODE B30A
SAN FRANCISCO CA 94120
(415) 973-2491
jmrb@pge.com
For: Pacific Gas and Electric Company

Karen P. Paull
Legal Division
RM. 4300
505 VAN NESS AVE
San Francisco CA 94102
(415) 703-2630
kpp@cpuc.ca.gov
For: ORA

Charles Manzuk
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK COURT, CP 32D
SAN DIEGO CA 92123
(858) 636-5548
cmanzuk@semprautilities.com
For: San Diego Gas & Electric

Justin D. Bradley
SILICON VALLEY LEADERSHIP GROUP
224 AIRPORT PARKWAY, SUITE 620
SAN JOSE CA 95110
(408) 501-7864
jbradley@svlg.net

APPENDIX A
LIST OF APPEARANCES

CONCORD CA 94520
(925) 743-1292
Service@spurr.org
For: School Project for Utility Rate Reduction

Nina Suetake
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE 350
SAN FRANCISCO CA 94102
(415) 929-8876
nsuetake@turn.org

(END OF APPENDIX A)

APPENDIX B

LIST OF ACRONYMS AND ABBREVIATIONS

A.	Application
AB	Assembly Bill
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
C&I	Commercial and Industrial Customers
CEQA	California Environmental Quality Act
CPMR	Customer Preference Market Research
CPP	Critical Peak Pricing
D.	Decision
DCSI	Distribution Control Systems, Inc.
DRA	Division of Ratepayer Advocates
O&M	Operating and Maintenance Costs
PG&E	Pacific Gas and Electric Company
PVRR	Present Value of Revenue Requirements
R.	Rulemaking
RFP	Request for Proposal
SMUD	Sacramento Municipal Utility District
SPP	Statewide Pricing Pilot
SPURR	The School Project for Utility Rate Reduction
SSJID	The South San Joaquin Irrigation District
SVLG	The Silicon Valley Leadership Group
TOU	Time of Use
TURN	The Utility Reform Network
Yolo/Cities	The County of Yolo and Cities of Davis, West Sacramento, and Woodland

(END OF APPENDIX B)

 Date of Issuance 3/13/2009

Decision 09-03-026 March 12, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Upgrade its SmartMeter™ Program (U 39 E).	Application 07-12-009 (Filed December 12, 2007)

(See Appendix A for a list of appearances.)

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED UPGRADE TO THE SMARTMETER PROGRAM

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DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED UPGRADE TO THE SMARTMETER PROGRAM

1. Summary

By this decision, we authorize Pacific Gas and Electric Company (PG&E) to proceed with its proposed SmartMeter Program Upgrade at a cost of $466,760,000, subject to the conditions specified in this decision, and to increase revenue requirements to recover the related costs.

The principal components of this electric meter upgrade include an integrated load-limiting connect/disconnect switch, a home area network gateway device and an advanced solid state meter. With the authorization of the upgrade to PG&E's previously authorized advanced metering infrastructure program, the devices and functionalities are now comparable to that previously authorized for San Diego Gas & Electric Company and Southern California Edison Company.

Briefly, the decision:

ffi Adopts PG&E's incremental meter device cost estimates.

ffi Reduces incremental cost estimates for certain retrofit, demand response program, project management, information technology, operation and maintenance and technology assessment costs, along with related contingencies.

ffi Determines that, on a present value revenue requirement basis, the upgrade is cost effective.

ffi Adopts a two-tier peak time rebate for PG&E and defers the design of the incentive and funding of the program to PG&E's November 2009 rate design window filing.

ffi Denies a request to exclude street light customers from the rate increase.

ffi Orders PG&E to pursue automated meter reading for water meters, by working with the water utilities in its service territory, either through multi-party workshops or direct dialogue.

This proceeding is closed.

2. Background

The Commission opened Rulemaking 02-06-001 as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment.[1] PG&E's Application (A.) 05-06-0281 emerged from the Rulemaking and was PG&E's proposal for full deployment of an advanced metering infrastructure (AMI).

By Decision (D.) 06-07-027, the Commission authorized PG&E to deploy its AMI project, which included automation of its gas and electric metering and communications network (5.1 million electric meters and 4.2 million gas meters) and consisted of metering and communications infrastructure as well as the related computerized systems and software. Most of the meter inventory was to be retrofitted with communications modules and redeployed.[2] The Commission adopted as reasonable a project budget of $1.7394 billion, inclusive of a risk based allowance, or contingency, of $128.8 million and $49 million for pre-deployment costs approved in D.05-09-044. The Commission also adopted PG&E's rate proposal for critical peak pricing (CPP) tariffs.

The authorized AMI project was cost effective in that the present value revenue requirement (PVRR) of the project costs, $2,258.3 million, was more than offset by the sum of the PVRR of operational benefits, which amounted to $2,024.2 million, and the

[1] *Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing*, filed June 6, 2002 and closed by D.05-11-009.

[2] D.06-07-027 indicates that PG&E's plan was to retrofit 54% of the existing electric meters and 96.1% of its existing gas meters.

PVRR of the demand response benefits associated with the CPP tariffs, which amounted to $338 million.

Since the approval of PG&E's SmartMeter Program the market in this area has evolved rapidly. PG&E believes that the pace of this development was enhanced by the approval of PG&E's SmartMeter Program which signaled greater opportunities for vendors of advanced metering equipment, communication technology and in-home devices needed to support utility advanced metering initiatives. Further incentive has been provided by the applications of the other major investor-owned utilities (IOUs) in California for AMI programs. PG&E states that the result, since the approval of its original SmartMeter Program, has been substantial innovation and significant reductions in cost.

On December 12, 2007, PG&E filed A.07-12-009, the focus of this decision, requesting authority to further increase rates related to its AMI project (now referred to as its SmartMeter Program) in order to upgrade three elements of its SmartMeter Program technology. The three elements of the SmartMeter Program Upgrade (or Upgrade), are:

ffi Incorporating an integrated load-limiting connect/disconnect switch into all advanced electric meters;

ffi Incorporating a Home Area Network (HAN) gateway device into advanced electric meters to support in-home HAN applications; and

ffi Upgrading PG&E's electric meters to solid state meters to support the above functionality and to facilitate upgrades.

PG&E states that through this SmartMeter Program Upgrade, it will create a foundation for building an infrastructure that will enable and empower new ways of looking at energy use. New possibilities exist in the areas of energy efficiency, customer satisfaction and system reliability.

PG&E estimates $572,453,000 in Upgrade costs that are incremental to those costs authorized by D.06-07-027. The PVRR of the incremental costs is $841,157,000, which is offset by incremental operational, conservation and demand response benefits estimated by PG&E to be $1,063,124,000 (PVRR).

A prehearing conference was held on February 8, 2008, and the Assigned Commissioner's Ruling and Scoping Memo was issued on March 13, 2008. The Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), and the California City-County Street Light Association (CAL-SLA) each issued testimony on June 30, 2008. PG&E and the City and County of San Francisco (CCSF) each issued rebuttal testimony on July 23, 2008. Evidentiary hearings were held from August 4 through August 8, 2008. Opening briefs were filed by August 29, 2008. Reply briefs were filed by September 12, 2008, at which time this proceeding was submitted for decision.

3. PG&E's Request

In its application, PG&E specifically requests that the Commission:

1. Approve PG&E's SmartMeter Program Upgrade for construction and deployment as described and proposed;

2. Allow PG&E to recover the actual costs of the Upgrade without further reasonableness review if the actual cost of the Upgrade is less than or equal to $623 million[3] and to recover additional reasonable amounts, if any, upon appropriate Commission review;

3. Adopt PG&E's proposed balancing account and other ratemaking mechanisms to track actual costs and pre-approved benefits of the Upgrade;

4. Adopt PG&E's proposal of using forecast benefit amounts, as presented in this Application, tied to the actual project deployment schedule, for providing operating benefits of the Project to customers, and also recognizing other benefits associated with demand response and energy conservation;

[3] Since revised to $572 million.

5. Approve the Upgrade forecast revenue requirements presented in this Application as the starting point for Project rates; and

6. Adopt PG&E's proposal for changing electric rates on January 1, 2009 and on January 1, 2010, based on the approved forecast revenue requirements, combined with balancing account balances that true-up for actual costs and credited benefits estimated for each rate change date, and any other permission and authority necessary to implement the proposed rates.

As part of this proceeding, PG&E also requests authority to implement its peak time rebate (PTR) proposal and recommends a single tier tariff to do so.

4. Positions of the Other Parties

Briefly, the positions of the other parties are as follows:

4.1. DRA

DRA recommends that PG&E's Upgrade proposal be rejected, arguing that it is not cost-effective. While DRA estimates that the advanced meters with the HAN gateway device, integrated load-limiting connect/disconnect switch and communication device can be procured at a substantially lower cost than estimated by PG&E and maintains that certain other costs estimated by PG&E related to project management, meter retrofits and technology assessment are excessive, its estimates of benefits do not cover its estimates of adjusted costs. DRA accepts PG&E's estimate of operational benefits and a portion of electric conservation benefits, but for various reasons rejects PG&E's estimate of gas conservation benefits, PTR benefits and Title 24 programmable communicating thermostat (PCT) benefits for use in evaluating the cost effectiveness of the Upgrade. DRA also proposes a two tier PTR rate design as opposed to the single tier proposal by PG&E. DRA also recommends that PG&E should further investigate the cost effectiveness of augmenting its SmartMeter Program to allow remote meter reading of customers' water usage for the larger water companies in PG&E's service territory.

4.2. TURN

TURN recommends that the Commission reject this application, asserting that (1) the operational benefits of the Upgrade project do not justify its costs, and the program is highly unlikely to produce the demand response benefits that PG&E expects; and (2) the AMI system with the HAN technology is expected to obtain the same demand response benefits that would have been obtainable with a cheaper, less risky air conditioner (AC) cycling switch and it would be unreasonable to spend $572 million dollars for such results.

If the Commission proceeds with any part of the application, TURN proposes that failure by PG&E to achieve 65% of the megawatt (MW) savings approved in D.06-07-027 and 100% of the additional PTR and PCT MW savings projected in this application should result in penalty payments to ratepayers.

4.3. CCSF

CCSF opposes PG&E's request for a number of reasons including poor technological choices in the original AMI proposal, little evidence to show the estimated benefits will actually occur, and its perception that the actual deployment of meters is not commensurate with the amount of money spent so far on the project.

With respect to DRA's recommendation that PG&E investigate the possibility of remotely reading water meters for water companies within its service territory, CCSF agrees that, to the extent feasible, water and electric utilities should be cooperating and working together in the best interests of their common customers. Because the City's water utility is in the process of implementing its own AMI system, the City indicates it is willing to work with PG&E to avoid system redundancy.

4.4. CAL-SLA

CAL-SLA opposes PG&E's proposal to increase street light rates for the Upgrade costs, because SmartMeters won't be installed in street lights and there are no demonstrated and proven cost benefits to the street light class.

5. Choice of Technologies

As indicated, there are three principal elements to PG&E's Upgrade request – the HAN gateway device, the integrated load limiting connect/disconnect switch and the advanced solid state meter. The devices are described below. DRA supports the deployment of these particular devices, as long as it is cost effective to do so.

5.1. HAN Gateway Device

The HAN gateway device will enable two-way communications directly into a customer's home. A key feature of the new communications technology will be to give customers near real-time access to their energy usage data. PG&E envisions this technology will enable it to send time and price indicators to the customer's meter, giving the customer the opportunity to participate in demand response, time of use (TOU), and other energy management initiatives. PG&E provides the following support for deployment of the HAN device:

- The emerging home area network technology is integral to the future of energy usage, conservation and management. In the future, appliances and other energy using devices will be more intelligent than they are today. To take advantage of this intelligence, the appliances will need to receive a signal regarding the price and availability of electricity. The HAN gateway device would provide the capability to transmit the information from the meter to these smart appliances, energy management systems and other energy using devices. The HAN gateway device that PG&E would deploy is the bridge between PG&E's network and the customer's home area network. The gateway device will facilitate customers' management of their energy usage via their connection to PG&E's network and the information that will travel among the devices in the residence, the customer's meter and PG&E.

- The HAN gateway device will position PG&E with a platform that has the potential to communicate with programmable communicating thermostats that are expected by PG&E to be required by the California Energy Commission (CEC) through Title 24 in all new and selected existing premises beginning in 2012.

- The HAN gateway device in combination with the solid state meter and AMI will enable PG&E to better respond to load reduction directives issued by the California Independent System Operator (ISO). This is because PG&E will be able to confirm the fact that key energy using devices have responded and will aid in the quantification of the amount of demand response achieved. This capability would support the minimization of the discount factor that is currently applied to some demand response programs when PG&E files its resource adequacy plans. Timely and affirmative verification of load reduction will lead to better forecasting, increased understanding of program performance and a reduction in resource procurement.

5.1.1. CCSF's Position

CCSF argues that the Commission should not approve PG&E's Upgrade to the extent PG&E would install HAN gateway devices in all of its electric meters. According to CCSF, the technology PG&E seeks to deploy is not yet commercially available, and PG&E cannot guarantee when its chosen endpoints will be available for deployment at all, let alone in sufficient quantities for PG&E to deploy nearly five million meters on a timely basis. CCSF adds that the industry has still not set standards for HAN connectivity, and it is very possible that PG&E will deploy five million devices that do not meet the eventual standards and will require upgrading again in a few years.

CCSF also states that the HAN system need not be included in the meter, but instead could be separate from the meter. According to CCSF, deployment in this manner, rather than through the endpoints, would insure that the costs of acquiring a HAN network are appropriately allocated to those customers who would chose to purchase such a network because they are likely to benefit from HAN products and services.

Finally, CCSF states that San Francisco residents are not likely to be among those who would benefit from HAN technology for two reasons. First, there is a larger percentage of renters and persons living in multiple dwellings in San Francisco than there is in the rest of the State of California. According to CCSF, these types of customers generally use less energy than other residential customers, and might not want to incur the expense to purchase HAN-enabled appliances. Second, because of its climate, San Francisco residents are less likely to have central air conditioners, which would be one of the primary sources of reduced electrical use.

Regarding CCSF's first argument, PG&E states that CCSF ignores the fact that the Commission has already found that the time is ripe for SDG&E to deploy HAN devices[4] and the Commission has issued a proposed decision[5] that would authorize SCE to deploy HAN devices. According to PG&E, in order to promote statewide consistency for this developing industry, the timing is excellent for PG&E to work with SDG&E and SCE and to deploy devices with consistent standards. PG&E adds that CCSF's argument also ignores the work proposed by PG&E in the Upgrade to shape the development of this burgeoning industry and to ensure that there is a statewide open standard for HAN communication systems that is secure, upgradeable and extensible.

Regarding CCSF's second argument on the merits of a stand-alone HAN device, PG&E asserts that it lacks evidentiary support, in that CCSF's argument finds its source in the study of SmartMeters conducted by CCSF that was excluded from the record of this proceeding.[6] According to PG&E, while the administrative law judge clarified that "[m]uch of the information in the contemplated study as it relates to the testimony submitted in this proceeding can be provided by the City to the Commission through the briefing process," there is no testimony submitted in this proceeding on the value of stand-alone HAN devices; and CCSF's argument is thus substantively and procedurally improper and must be rejected.

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[4] D.07-04-043.

[5] A final decision, D.08-09-039, was issued, and authorizes SCE's deployment of HAN devices.

[6] In an oral ruling, the administrative law judge denied the request of CCSF to leave the record open for the purpose of considering an upcoming study on PG&E's SmartMeter Program that would be conducted by certain departments within CCSF. *See* 5 RT 779-781.

Regarding the third argument, PG&E states that CCSF ignores the fact that renters have financial incentives to reduce their energy costs, just as owners do. PG&E believes that all customers, whether they are renters or owners, deserve the opportunity to use HAN devices to reduce their energy consumption and that it is good public policy to promote such reductions.

5.1.2. Discussion

This is an appropriate time to authorize deployment of HAN gateway devices for PG&E. PG&E's request to do so is reasonable. We have already authorized such deployment for both SDG&E and SCE, and to do for PG&E would ensure statewide consistency as long as their efforts are coordinated. We feel such consistency is important in providing a basis on which the HAN technology can efficiently develop and for providing a large market force that can be influential in developing appropriate standards. Also, as part of this decision, we authorize funds for PG&E to continue to work with the other utilities is California and throughout the United States to establish standards for HAN technology and applications. In authorizing deployment of HAN devices for PG&E at this time, we feel reasonably assured that the utility will be able incorporate this evolving technology in its meter deployment plan.

We are unable to judge the merits of a stand-alone HAN gateway device. As indicated by PG&E, there is no evidentiary record in this proceeding regarding such a device, since this issue was raised by CCSF in its opening brief that was filed on August 29, 2008. The proper time to have raised this issue was June 30, 2008 when intervenor testimony was due. That would have allowed time for discovery and rebuttal testimony and provided the opportunity for cross-examination by other parties during evidentiary hearings. That being said, if a customer has no need for the HAN gateway in the meter, and if a stand-alone HAN system is available, we see no reason why that customer should not have the opportunity to purchase and use such a system separately from the HAN gateway provided by PG&E through its meter. The important point is that all customers should have the opportunity to use HAN devices to reduce their energy consumption, and it is good public policy to promote such reductions. However, for that same reason, customers should have the opportunity to use the HAN gateway through PG&E's meter, and we feel the most cost effective way to provide that access, over the long term, would be through PG&E's meter deployment plan rather than through random retrofits.[7]

To facilitate the HAN concept, PGE should work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

5.2. Load Limiting Switches

PG&E explains that when it developed its original AMI application in 2005 (A.05-06-028), the most cost-effective option for remote meter "turn-on/turn-off" was to add a "connect/disconnect collar" mounted separately and in conjunction with the electromechanical meter. Thus, PG&E's original project included adding a connect/disconnect collar to 600,000 electromechanical meters. Because of advances in solid state meter and load limiting switch technology, as well as decreases in the relative costs of the components, PG&E now proposes to install integrated load limiting switches for all of PG&E's residential and single phase, 200-amp, self-contained meter customers. PG&E provides the following support for deployment of the integrated load limiting switch:

ffi It is important to provide all residential electric customers with a load limiting switch, not just the 600,000 envisioned in the original AMI Application, so that the PG&E's customers, the utility and the state of

[7] Evidence in this proceeding indicates that the incremental costs of installing a HAN gateway device after the meter and disconnect switch have already been installed is nearly nine times the cost of the HAN gateway device. For example, see Exhibit 8WC, the eighth page (unnumbered) of the Appendix 10-1 workpapers.

California (State) can benefit from the increased functionality provided by the new switches. The new load limiting switches provide significantly more functionality compared to the collar associated with the electromechanical meters. That is because the switch built into the collar was designed as an on/off toggle, was not integrated into the metrology of the meter and, therefore, provides no real opportunities for load limiting and energy management programs. On the other hand, the load limiting ability of the new switch is created by the joining of a programmable connect/disconnect switch with an intelligent solid state meter and integrating these components with the two-way communications capability delivered by PG&E's AMI system. The switch will enable the development of different options that will allow customers and PG&E to control not just whether the power is on or off, but how much power can be used at any given time, and this combination of technologies results in adjustable load limiting capabilities around which a variety of programs and/or rate offerings can be designed to take advantage of this flexible energy service control tool.

ffi The increased functionality of the load limiting switch will also help PG&E and the State in designing and implementing improved demand response programs that will reduce overall energy usage, will reduce load on the system and will improve overall reliability of the system. The presence of load limiting switches could help the ISO and PG&E to provide area-wide and system-wide relief during peak usage periods without completely shutting down critical systems. This view is corroborated by the Federal Energy Regulatory Commission (FERC) in their 2007 Assessment of Demand Response and Advanced Metering report which states, "remote connect/disconnect may also be valuable for its ability to avoid extended outages and overloading of transformers at critical peak by allowing grid operators to disconnect customers where lines are stressed. The ability to ensure less energy is used by PG&E's customers in capacity or infrastructure constrained areas will lead to fewer customer outages, fewer required distribution assets and less generation.

5.2.1. CCSF's Position

CCSF states that PG&E appears to be putting forth the ability to limit load to essential services through the endpoints as a means of "keeping the lights on" to some degree, rather than incur rolling brown or black outs, and this explanation would appear to include the belief that this feature will curtail the use of video games and other non-essential electrical uses. CCSF argues that these load-limiting switches reduce loads indiscriminately, and it would be incumbent on PG&E's customers to choose how they will use the reduced amount of electricity that PG&E would make available. According to CCSF, customers, especially small customers, with little in the way of non-essential load, still would have paid the price for instituting measures to control loads used by higher energy users.

CCSF also states that there is no evidence in the record that the software required to effectively manage these load limiting switches is presently available, or even that it is expected to be available any time soon.

It is CCSF's position that, since it appears that PG&E's remote connect/disconnect switch is an investment that PG&E has only proven to have operational value when used with delinquent customers, there is no reason that the Commission should authorize PG&E to install this functionality on all residential meters.

In response, PG&E states that CCSF ignores the evidence provided by PG&E that explains the variety of benefits available from these devices. First, the devices provide PG&E with the ability to remotely connect or disconnect customers. Second, the devices provide PG&E and state officials a platform upon which to design new rate options for customers. Third, the devices would give greater control to the ISO and PG&E to provide area-wide and system-wide relief during peak usage periods without completely shutting down critical systems. This should result in fewer, or shorter, outages. PG&E adds that the operational benefits from the first category alone amounts to over $150 million (PVRR), an amount that has not been challenged.

5.2.2. Discussion

We agree with PG&E that the increased functionality and the potential uses of the integrated load limiting connect/disconnect switches justifies providing all electric residential customers with such switches. This functionality could be used to implement certain demand response programs and to provide area-wide and system-wide relief during peak usage periods. Such opportunities are in the public interest and are not available under PG&E's original AMI program. Also, the integrated load limiting connect/disconnect switch provides significant incremental operational benefits related to field technician labor savings for connect/disconnect services.

Finally, we note that CCSF raised the issue regarding the availability of the software required to effectively manage the load limiting switches in its opening brief. We also note that CCSF does not provide any reason why it believes that the necessary software does not exist or will not exist soon. This issue should have been raised in prepared testimony so that an evidentiary record could be developed through rebuttal testimony and evidentiary hearings. In its testimony, PG&E has acknowledged that modifications and interface changes will be required to create new credit/collection templates, start/stop algorithms, and partial load limiting functionality[8] and has included such costs in its information technology system integration chapter.[9] While nothing is certain, PG&E is taking reasonable steps to ensure the effective operation of the integrated load limiting connect/disconnect switches.

5.3. Advanced Solid State Meter

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 ubiquitously. PG&E states that the solid state meter will be the

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[8] In this proceeding, PG&E has not proposed to implement any of the load limiting capabilities of these switches, but rather only the connect/disconnect capability.

[9] *See* Exhibit 3, Chapter 4, pp. 4-5 through 4-6.

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. All of these things, and potentially more features in the future, are possible because of the increased processing power, memory storage, programmability, and upgradeability provided by the solid state meter platform. PG&E provides the following support for deployment of the advanced solid state meter:

- As PG&E and other utilities demonstrate the need for, and interest in, advanced metering technology to support their advanced infrastructure projects, the industry's vision has expanded, the functionality of the new meters has increased and the prices for solid state meters and other integrated components have decreased. The current generation of solid state meters is programmable, have additional data storage capacity and possess processing capabilities that will expand both the usefulness and the reliability of the meter. Unlike electromechanical meters, current generation solid state meters are the only meters that have the native capability to support communication with HAN and the integrated load limiting switch.

- As a result of the advanced processing capabilities and the memory built into the solid state meter, as well as the communications provided by PG&E's AMI communications network, PG&E will be able to upgrade meter functionality remotely by communicating changes to a combination of both the software and the firmware inside the solid state meters, thus taking advantage of how these devices are designed. The capability to upgrade the meter (as well as the AMI and HAN devices) gives PG&E greater flexibility to respond to changes in technologies and marketplace developments and helps to "future-proof" these technologies.

- The increased memory at the meter device will provide a platform for more reliable data integrity. The increased reliability results from the ability to store more data at the meter device, data that can be specifically identified with the residence before it is centralized with other information in PG&E's databases. Because some historic usage data will also reside at the meter device, PG&E anticipates that this will provide an alternate source of data to resolve various customer billing issues.

ﬃ Additionally, because of the increased memory at the meter device, PG&E will be able to collect greater amounts of usage data which could support valuable research studies. Such studies could provide useful information to PG&E in support of a variety of operations and maintenance procedures and could be used to develop studies that PG&E anticipates would be valuable to the ISO, other agencies and the State as they work to manage distribution grids and electricity consumption.

No party disputes the technological merits of the advanced solid state meter or PG&E's decision to deploy it ubiquitously as part of the Upgrade. PG&E's decision to do so is reasonable.

5.4. Network Technologies

As part of its original AMI proposal in A.05-06-028,

> PG&E selected Distribution Control Systems, Inc. (DCSI) to provide a Power Line Carrier technology for electric meters and Hexagram, Inc. to provide a fixed network system with radio frequency communication channels owned by PG&E for gas meters. These selections followed a detailed Request for Proposal (RFP) and evaluation process. PG&E's testimony showed that the DCSI system has been deployed by a number of other utilities (none as large as PG&E) to provide a sufficient demonstration of the technology's reliability and functionality. The technology provides two-way communications to each customer's meter. The technology also allows other functions including direct polling to the meter by PG&E which can assist in completing customer service related requests; and it has the potential for direct communication with in-home devices like thermostats and load control switches."[10]

PG&E indicates that it is evaluating the possible implementation of an enhanced communication network, which would be implemented without seeking any additional

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[10] D.06-07-027, pp. 18-19.

costs for that network in this application, and would provide greater benefits than the power-line-carrier technology discussed in A.05-06-028.

5.4.1. DRA's Position

While DCSI employs a power line carrier technology, Hexagram's technology is radio frequency (RF) based. DRA understands that PG&E is considering a Silver Springs Networks RF technology to replace the DCSI power line technology for electric customers. DRA does not believe that two separate and overlapping RF networks, one for gas and a separate network for electric are well advised. DRA states that a single RF system by various vendors, including Aclara[11] RF or Silver Springs RF is capable of doing both. DRA is indifferent to the choice of Aclara RF versus Silver Spring RF, provided that the costs of the change and the additional costs of operating and maintaining two RF systems are not borne by ratepayers. According to DRA, a single RF system serving both the gas and electric metering requirements in all but the deep rural areas was the obvious choice from the outset of the PG&E project.

In response, PG&E states that DRA provides no evidence to support the contention that a single RF network is better than dual networks for gas and electric and also contradicts its own prior position on this issue.

PG&E states that the Upgrade seeks no funding for its network technologies, and the costs of managing its networks – including the change to a RF mesh network for electric – will be handled as part of the funding provided in the original AMI case. PG&E also states that despite DRA's opinion in the original AMI case that, "[m]ixed technology systems, tailored to the applications and as proposed by a number of highly competent firms, would ordinarily be a more attractive choice than stretching the capabilities of a single communications technology" and that the choice would ultimately come down to an economic one, DRA now contradicts its former position and attempts to

[11] Aclara was formerly known as Hexagram.

assert that a single technology for the network is always a better choice. PG&E also adds that DRA's witness testified during the hearings that he did not perform any economic analysis comparing PG&E's proposed dual network infrastructure. Therefore, PG&E argues that DRA has no basis for making these claims.

DRA has not made a functional distinction between traditional RF based networks such as Aclara RF and RF Mesh based networks used by Silver Spring Networks. By treating the Aclara RF and Silver Spring Networks technology as fungible, PG&E indicates that DRA ignores the key differences in functionality between the two technologies, namely that an RF Mesh system does not have the same economic disadvantages as RF-based systems in rural areas, because it is not limited to moving data from a meter to a data collection unit in a single fixed path and therefore requires a less costly data collection unit infrastructure. PG&E also states that Silver Spring Networks does not have a proven and established product for gas meters and therefore it would not be advisable to use this technology for the gas meters.

5.4.2. Discussion

In its Upgrade request, PG&E is not requesting additional funds for either its electric or gas networks, and we will not authorize any such increases in this decision. We recognize that certain technologies have evolved over the course of PG&E's SmartMeter project making them more cost-effective to employ, and we expect PG&E to manage the project in a way such that the more cost-effective approaches can be merged into the deployment plans. For this reason, we will not impose conditions regarding the specific type of communications network or types of networks that PG&E should employ for its electric and gas AMI systems. We only require that whatever PG&E chooses to do, the selected network(s) must provide the necessary functions in the most reasonable cost-effective manner.

6. Cost-Benefit Analysis

6.1. Incremental Cost/Benefit Analysis

PG&E has presented its estimate of the incremental costs and benefits associated with the Upgrade as detailed in Tables 1 and 2 below. PG&E's estimate of incremental costs is $841 million (PVRR), while its estimate of incremental benefits is $1,063 million (PVRR). By PG&E's estimates, incremental benefits of the Upgrade exceed incremental costs by $222 million, and the Upgrade is thus cost effective. As discussed further on in this decision, other parties disagree with PG&E's definition of incremental costs and benefits, as well as with PG&E's quantification of costs and benefits.

Table 1
PG&E's Estimates of Incremental Costs

	Incremental Costs	
	Nominal	**PVRR**
	(Dollars in thousands)	
Deployment Costs		
Meter Devices (Less HAN and Electromechanical Meter Upgrades)	$ 310,757	$ 486,358
HAN Retrofit	32,032	29,676
Electromechanical Meter Retrofit	37,312	40,431
Information Technology	48,433	52,589
Title 24 Program Costs	-	37,906
Peak Time Rebate Costs	18,342	27,592
Project Management	15,318	17,954
Training	1,697	1,592
Risk Based Allowance	57,371	55,568
Subtotal	$ 521,262	$ 749,666
Operations and Maintenance Costs		
Operations and Maintenance	$ 5,129	$ 49,435
Risk Based Allowance	582	521
Subtotal	$ 5,711	$ 49,956

Other Costs		
Technology Assessment	$ 37,900	$ 35,285
Risk Based Allowance	7,580	6,249
Subtotal	$ 45,480	$ 41,534
Total Incremental Costs	$ 572,453	$ 841,156

Table 2
PG&E's Estimates of Incremental Benefits

	Incremental Benefits (Dollars in thousands)	
	Annualized	**PVRR**
Operational Benefits		
Integrated Connect/Disconnect Switches		
Avoided Field Visits	$ (6,682)	$ (114,702)
Improved Cash Flow	(969)	(11,174)
Reduced Bad Debt	(2,429)	(26,756)
Tax Benefit from Meter Replacement	n/a	(11,799)
Subtotal	$ (10,080)	$ (164,431)
Energy Conservation/Demand Response Benefits		
Electric Conservation	n/a	$ (311,881)
Gas Conservation	n/a	(167,190)
Peak Time Rebate	n/a	(290,222)
A/C Cycling	n/a	(129,401)
Subtotal	n/a	$ (898,694)
Total Benefits	n/a	$ (1,063,125)

PG&E considers any costs and benefits related to its total AMI project (original plus Upgrade) that were not specifically included in the original AMI project cost/benefit analysis to be incremental for the purposes of justifying the cost effectiveness of the Upgrade. For instance, the PTR program will be functional with the completion of the Upgrade. The costs and benefits of the PTR program were not included in the original AMI project cost/benefit analysis. PG&E has therefore included the PTR program in the cost/benefit analysis used to justify the cost effectiveness of the Upgrade. As described above, using this definition of "incremental" and PG&E's estimates of costs and benefits results in the cost effectiveness scenario where Upgrade proposal benefits exceed costs by $222 million.

6.1.1. Positions of the Other Parties

DRA believes that Upgrade benefits that could have been achieved by the original AMI system that was approved by the Commission in D.06-07-027, should be excluded from the cost-effectiveness analysis for the Upgrade. For instance, DRA excludes PTR benefits from the Upgrade analysis because, in its opinion, PTR can be implemented with the functionalities of the meter equipment that was included in the original AMI project. DRA argues that, if benefits could have been achieved by the original system, they are not truly incremental benefits made possible with the Upgrade. Using this definition of "incremental" and DRA's estimates of costs and benefits results in a cost effectiveness scenario where Upgrade proposal costs exceed benefits by $76 million.

TURN and CCSF agree with DRA's definition of incremental. TURN also notes that, as early as May 2005, PG&E stated to the Commission (justifying its original authorization) that its proposed AMI system could accommodate, not only the rates that were identified by the Commission, but also any future dynamic tariffs that might be contemplated by the Commission over time. Thus, according to TURN, it is analytically incorrect to apply demand response benefits to this "AMI Upgrade" because (a) PG&E's original technology choice clearly is able to measure hourly data necessary for implementing a PTR and (b) PG&E has testified to the Commission that its original AMI technology had the technical flexibility to accommodate any future changes in to dynamic rates.

In response, PG&E states that "incremental costs" are costs beyond what were identified in the original project, "incremental benefits" are benefits beyond what were originally identified original and incremental costs should equal total costs, and original benefits and incremental benefits should equal total benefits. PG&E asserts that DRA's definition of incremental is unduly restrictive and unreasonable, because it eliminates any benefits that could have been achieved with PG&E's original AMI technology even though such benefits were not counted in the first case and it undervalues the benefits that will be achieved through the HAN device and IHDs.

PG&E adds that DRA's thesis is further undercut by the fact that the level of conservation and demand response benefits PG&E claims in the Upgrade could not have been achieved without the further expenditures contained in the Upgrade. While the original technology certainly created the foundation for such benefits, further expenditures for IT and the HAN were still required.

PG&E also states that DRA's position is fundamentally unfair in that DRA penalizes PG&E for being a leader in bringing advanced metering to California and implementing its SmartMeter program in two phases and DRA's approach denies PG&E the ability to count benefits that its SmartMeter Program will generate – benefits that SCE and SDG&E are able to count in their respective business cases. PG&E argues that it should not be treated differently than the other California IOUs just because PG&E's project is being deployed in two phases.

6.1.2. Discussion

Parties agree that an incremental analysis is the proper way to analyze the cost effectiveness of the Upgrade. In its application showing, PG&E justifies the Upgrade on an incremental basis, and DRA and the other parties have evaluated PG&E's request assuming an incremental analysis, but defining "incremental" differently than PG&E, as described above.

There is much to be said for DRA's definition of incremental. Certainly if the Upgrade were cost effective under that definition, all parties would agree that it would be economically justified. However, there are factors that lead us to believe that, for the purposes of this proceeding, DRA's definition of incremental based solely on functionality is unduly restrictive.

First of all, DRA rejects all PTR benefits as estimated by PG&E under the assumption that all PTR related benefits could have been achieved through the original AMI project. DRA makes this assumption based primarily on the time differentiation function of the original AMI project. We agree with PG&E that PTR benefits are augmented by the HAN functionality.[12]

Also, PG&E correctly points out that the levels of conservation and demand response benefits PG&E claims in the Upgrade cannot be achieved without the further expenditures contained in the Upgrade. Much of the PTR program costs and associated IT costs, as contained in PG&E's Upgrade request, are essential for obtaining the conservation and demand response benefits as justified and forecast by PG&E. Those costs were not included in PG&E's original AMI case, so it is highly likely that, without these Upgrade expenditures, the benefits would not be derived to the extent estimated by PG&E, if at all. From that standpoint, PG&E's use of incremental makes some sense in that the realized benefits directly derive from the incremental Upgrade costs, even those benefits that might be associated with the original AMI project functionality. It might make more sense to have assigned or allocated PTR program and associated IT costs to both the original AMI project and the Upgrade. That would be a way to determine the truly incremental PTR costs associated with the Upgrade, assuming that PTR would have been provided as part of the original AMI project. We only note that such an analysis was not done.

Furthermore, DRA's definition of incremental results in PTR benefits not being recognized at all for SmartMeter program cost effectiveness purposes. For PG&E, PTR program benefits were not included in the original AMI case and, under DRA's proposal, would not be included in the Upgrade. We note that the PTR program was recognized as a benefit in the cost effectiveness analyses for both SDG&E and SCE in their AMI proceedings, and we see no reason to treat PG&E any differently. Under PG&E's

[12] For instance, TURN indicates that PG&E could have implemented PTR without the HAN functionality, but PG&E would have to spend and additional $5.7 million per year on marketing without HAN to achieve the same awareness level target.

definition of incremental, all appropriate AMI benefits are included in either the original AMI case or Upgrade cost effectiveness analyses.

In certain respects, DRA's definition of incremental is essentially at odds with the manner in which the Commission evaluated the AMI requests of SDG&E and SCE. Even though both SDG&E and SCE each filed only one application, an incremental analysis based on functionality could have been applied in determining the reasonableness of the requests. For example, based on what was authorized for PG&E in its original AMI application, the Commission could have analyzed SDG&E's and SCE's need for the additional functions (higher functioning solid state meters, integrated load limiting connect/disconnect switches and HAN Gateway devices) based on the specific cost effectiveness of those additional functions. In doing so, the Commission could have determined that CPP, PTR and certain aspects of electric conservation could be achieved with a basic system similar to that in PG&E's original AMI proposal and should not count as benefits to be associated with the proposed additional functionality of the HAN gateway, integrated connect/disconnect switches or advanced solid state meters. The Commission could have sought the minimal functionality, and least cost, that would be necessary to implement proposed benefits. However, the Commission did not go down that path in the case of either SDG&E or SCE. If it had, certain of the newer technologies and additional functionalities may well have been determined not to be cost effective and rejected.

Viewing costs effectiveness as we did for SDG&E and SCE and as proposed by PG&E provides for a certain amount of discretion on our part with respect to ensuring that our actions are consistent with good public policy and the overall long-term interests of the ratepayers. We support the concept of the new technologies and believe it would be inappropriate to reject them for PG&E simply because PG&E made its proposal in two phases as opposed to one phase.

For these reasons, PG&E's definition of incremental is reasonable and is in many ways consistent with the way the Commission viewed cost effectiveness for SDG&E and SCE. We will use it in our cost effectiveness analysis of the Upgrade.

6.2. Total Cost/Benefit Analysis

In its rebuttal testimony, PG&E raised the concept and issue of a total cost benefit analysis, when it evaluated the total of its original AMI case costs and benefits and its proposed Upgrade costs and benefits and compared the total results with those in the AMI cases for SDG&E and SCE.

According to PG&E, on a total basis, its SmartMeter program costs are $3.099 billion (including technology evaluation), while the most conservative benefit figure is $3.426 billion,[13] which results in benefits exceeding costs by 11%. PG&E compares this to SDG&E and SCE where a range of projected benefits resulted in benefits exceeding costs by a range of 6% to 8% for SDG&E and 0.6% to 18.6% for SCE.

6.2.1. DRA's Position

DRA opposes PG&E use of total cost/benefit comparisons, first of all, because there is insufficient information in the record to adequately compare PG&E's per meter costs with those of SCE and SDG&E. Beyond this, there is the significant question of whether applications for major capital expenditures should be evaluated on a total basis that includes the costs and benefits of a prior case. According to DRA, economists generally favor performing cost-benefit analyses on an incremental basis. The reason for this is because, even if a project can be justified on a total basis, if an incremental investment has a negative net present value, going forth with the incremental project

[13] PG&E states the benefit figure is conservative because it continues to use the figure of $52/kW-yr for the avoided cost of capacity for the initial portion of the project. If the figure were increased to $85/kW-yr as was done for the second portion of the project, the benefits increase to $3.598 billion. PG&E adds that if remote programmability benefits are also included, the benefits figure increases to $4.118 billion.

dilutes the costs and benefits of the initial project. Economists aim to maximize the net present value, and this requires that each increment stand or fall in terms of whether it adds net present value to the overall project.

Furthermore, DRA states that looking at both AMI cases on a total basis is extremely difficult to do in the post-rebuttal stages of the proceeding, and to now be asked to look at the case on a total cost and benefit basis is a violation of DRA's due process rights because an entirely different kind of analysis would have been required. DRA states that if it were to evaluate PG&E's case on a total basis, it would need to consider inefficiencies that have been produced by PG&E changing technologies and vendors after deploying more than half a million endpoints, adding that the most obvious inefficiency is the need to discard either entire endpoints or internal parts of endpoints and the additional labor costs involved in doing so. DRA concludes that if the Commission believes that this would be a preferable way to view PG&E's case, then it should reject the current application and ask PG&E to file a new case in which the analysis is presented on a total basis.

In response, with respect to DRA's argument that the costs of the other IOUs are not directly comparable, PG&E states that, even if some allowance were made for the differences, the inescapable conclusion remains that PG&E's overall costs for both phases compare favorably to SCE's and SDG&E's costs. More specifically, according to PG&E, this result further demonstrates that PG&E is managing all aspects of its project – original project, transition and Upgrade - in a reasonable manner.

With respect to DRA's argument that a total cost/benefit analysis does not include inefficiencies, PG&E states that its analysis includes all costs, including for example retrofit costs, one of the inefficiencies that DRA identifies.

6.2.2. TURN's Position

TURN asserts that the Commission should disregard any attempts to analyze the SmartMeter Upgrade project on a total cost basis, because there is insufficient data in the record to accurately engage in such an analysis. According to TURN, because costs and benefits that have been recorded so far are not on schedule with the costs authorized in D.06-07-027, in order to evaluate the Upgrade on a total project basis, PG&E would need to file the costs and benefits that have actually been recorded since the date of implementation of D.06-07-027 to today and reevaluate the total project costs going forward. TURN also asserts there are additional costs that have not been included in either the original AMI or Upgrade filings.

In response, PG&E indicates that it is true that the timing is different, but the fact remains that both costs and benefits were delayed. Further, PG&E indicates that, in spite of delays, it still intends to complete the whole project within the budget established by the Commission and to obtain the same benefits. In answer to TURN's argument that there are additional costs that will need to be added to the project cost, PG&E states that this assertion is wrong and that PG&E has included all known costs in its cost-benefit analysis.

6.2.3. Discussion

We agree with DRA and TURN that the record in this proceeding is insufficient for determining the cost effectiveness of PG&E's SmartMeter program on a total basis, especially when comparing PG&E with SDG&E and SCE. We do note though that PG&E has proposed an incremental analysis as discussed above, which is its principal justification for the Upgrade. It provides the total cost comparisons as additional justification for its request.

In concept, we do agree with PG&E that the original AMI costs and benefits plus the Upgrade costs and benefits would equal the total costs and benefits. However, it is uncertain whether all costs and inefficiencies have been included or not. Certainly the inefficiencies identified for the Upgrade would be reflected and TURN has not provided solid evidence of costs that have been omitted, but because PG&E's Upgrade proposal was not presented on a total basis, those types of issues were not necessarily analyzed in any detail. There is therefore some uncertainty as to whether all costs and inefficiencies are reflected correctly when looked at in total. For that reason, we would not use a total cost analysis as the basis for approving or rejecting the Upgrade. However, we see no reason why a total analysis cannot be used to show whether or not the cost effectiveness of PG&E's SmartMeter program is in the range or generally comparable to that of SDG&E and SCE. Our use of total analysis results will be limited to that.

6.3. Future Upgrade Cases

DRA recommends that the Commission provide clear directives to PG&E on how to present future upgrade cases. That is whether any such request should be presented on a total basis or on an incremental basis. DRA also believes there should be limitations on how frequently PG&E should be allowed to file upgrade applications.

In response, PG&E states that it has no plans for a further project upgrade. PG&E indicates that its goal was to achieve equivalent technology throughout the State. That goal will be accomplished by this decision. PG&E also indicates that the Upgrade will facilitate upgrades of both firmware and software, which means that in the future PG&E will be able to update both the functioning of the endpoint and initiate future programs without the necessity of visiting the endpoint. PG&E asserts that this aspect of the Upgrade should permit the current technology to perform capably well into the future even in the face of major advancements in technology.

With the authorization of the Upgrade and for the reasons cited by PG&E, we do not expect to see any further upgrade applications associated with the SmartMeter Program. We will not however prohibit or limit any such filings or prescribe the manner in which any such filings should be made. Future Commission actions should be guided by the circumstances that exist in the future, not on circumstances as they exist today. However, we expect that any future requests to upgrade the SmartMeter Program should be critically reviewed with the understanding that our interpretation of cost effectiveness in this proceeding is appropriate for the circumstances that exist today and may well be inappropriate for circumstances that exist in the future.

7. Costs

7.1. Meter Devices

In its application request, PG&E forecast $402,656,000 for incremental meter and equipment costs.[14] This amount covers HAN devices and load limiting switches for all customers, as well as the incremental costs associated with an advanced meter. PG&E indicates that it was, at that time, evaluating integrated meter devices proposed by a group of selected vendors and subsequently began to pursue an aggressive bidding process to obtain the best end-point technologies at the lowest possible price. In its May 14, 2008 Supplemental Testimony, PG&E indicated that it was then in the final stages of that process and had received "best and final" pricing from the remaining vendors in consideration. Due, in part, to the refined bids from these vendors, PG&E reduced its estimate for incremental costs associated with integrated meter devices to $342,789,000.[15] As opposed to its original estimate, this amount also covers the costs of retrofitting solid state meters deployed in 2008 without a HAN device (Ubiquitous HAN or HAN Upgrade) and the cost of HAN repeater devices (HAN Connectivity). According to PG&E, this also reflects a price structure that includes the option for a substantially better warranty on the end-point technologies.[16]

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[14] PG&E forecast costs of $606.575 million reduced by the costs approved in its original AMI project for electromechanical meters, remote connect/disconnect collars and real time output devices, which amounted to $203.919 million. The costs do not include that related to the electromechanical meter upgrade which is quantified and discussed separately.

[15] In its supplement, PG&E forecast costs of $607,819,000 reduced by the costs approved in its original AMI project for electromechanical meters, remote connect/disconnect collars and real time output devices, adjusted to reflect the estimated cost of the project decision to change from electromechanical meters to base solid state meters, which in total amounts to $265,030,000. The costs do not include that related to the electromechanical meter upgrade which is quantified and discussed separately.

[16] The costs set forth in PG&E's application included a five-year warranty on the end-point technologies, whereas the revised costs include an option to extend the warranty by an additional 15 years.

There are a number of issues related to meter devices including DRA's estimate of meter device costs, the HAN retrofit, the electromechanical meter retrofit (also known as the Kern County retrofit), and HAN connectivity.

7.1.1. DRA's Position

The only party to analyze the entirety of PG&E's proposed meter and equipment costs is DRA. Since DRA is supportive of the HAN and service switch, it recommends funding costs associated with this increased functionality. DRA estimates $267.3 million in incremental meter device costs derived from its own cost estimates for advanced solid-state meters that would have the same functionality as proposed by PG&E. DRA's consultant ultimately relied on confidential bids at his disposal from seven vendors. Having signed non-disclosure agreements to receive this information, DRA's consultant could not divulge the sources of this information or the underlying terms and conditions.

DRA notes that its consultant specifically used the lowest three bids amongst his sample set of seven, and that the average of the whole sample of seven produced a number in the same general range as PG&E's proposed cost. Knowing it could not produce enough benefits to justify PG&E's meter costs, DRA directed the consultant to use the lowest three to generate a "barebones" estimate. DRA also notes that the meters on which its consultant received quotes may have a lower level of functionality than do those that PG&E assumed in its presentation, however DRA states that it is unclear from the record what increased functionality PG&E's meters provide, or why this functionality is necessary.

From its cost estimate, DRA subtracted the funding that PG&E already received in A.05-06-028 for new or retrofitted meters. DRA also excluded all labor and network costs that were previously funded in A.05-06-028 except for labor costs associated with the Kern County retrofit. DRA included the labor costs for the Kern County retrofit because revisiting those meters would have been necessary anyway to provide the enhanced functionality.[17]

With regard to network costs, DRA's consultant states that further cost savings are available by using a single network for gas and electric meters in each geographical area. DRA was however unable to quantify these savings.

With regard to the determination of what meter costs were already approved in A.05-06-028 and should be subtracted from the cost of the advanced solid-state meters, DRA notes that in PG&E's May 2008 supplemental testimony, it assumed funding for a basic Tier 0 solid-state meter for all customers, while A.05-06-028 had only provided funding, for the residential sector, for replacing roughly one-third of the existing electromechanical meters, and merely refurbishing the rest of those meters at a fraction of the cost of a new one. PG&E's supplemental testimony includes a $61.1 million adjustment to its baseline costs for end-point technologies to reflect the estimated cost of the project decision to change totally from electromechanical to base solid state meters.[18] DRA states it did not adequately understand this evolution in PG&E's thinking, and its consultant merely followed what had been authorized in A.05-06-028, which provided funding to replace only one-third of the existing electromechanical meters rather than providing solid-state meters to everyone. DRA believes it would be appropriate to modify its figures to put them on a comparable basis with PG&E's revised numbers, suggesting in errata that PG&E's $61.1 million reduction be used as a proxy for the effects of putting its numbers on a comparable basis.

DRA stresses that the $61.1 million is only a proxy of this reduction, and that a larger reduction can be achieved by directly substituting a blended cost for a Tier 0 basic solid-state meter, for the cost of new and retrofit electromechanical meters in its Table 2-

[17] The Kern County retrofit is discussed in more detail elsewhere in this decision.

[18] Estimated incremental Upgrade costs were reduced by the $61.1 million amount.

1. According to DRA, doing this would more than compensate for other errors that PG&E alleges. However DRA indicates that it will refrain from further changing its estimates because there are compensating changes that could be made in both directions.

In response, PG&E states that DRA's original analysis is riddled with errors, which required DRA to make a number of corrections, one of which totaled nearly $200 million. Several additional errors were corrected in errata. PG&E indicates that it pointed out other errors to DRA that went uncorrected, including one that shorted PG&E about $10.5 million.

PG&E states that most importantly, after it pointed out DRA's errors, DRA changed its approach for this cost category and based its new recommendation on confidential pricing data from third parties that were never disclosed to PG&E. According to PG&E, DRA's unwillingness to disclose this third-party data -- on which it based its analysis -- deprived PG&E of its due process rights to examine such data and compare it to the data provided by PG&E.[19] PG&E quotes the following from DRA:

> …If you are asking me should PG&E know the other terms in order to effectively evaluate whether the product they are proposing to purchase is more cost-effective from their perspective than the alternatives I've proposed? I would say, yes, they need more information… .[20]

For the above reasons, PG&E argues that DRA's cost testimony should be given no weight.

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[19] Because of PG&E's concerns over the process followed by DRA, PG&E filed a motion to strike DRA's meter and equipment cost analysis. The motion was denied. However, in his oral ruling, the administrative law judge conceded the difficulty of relying on the evidence provided by DRA and indicated that any use of this information by the Commission in this proceeding will take into consideration the possible ramifications of the confidentiality restrictions, and the evidence would be weighed accordingly. *See* 5 RT 612-613.

[20] DRA, Levesque, 4 RT 553.

7.1.2. Discussion

DRA's recommended incremental cost for meter devices (the meter, disconnect switch, HAN gateway device and AMI module) is approximately $206 million, while PG&E's proposed amount is approximately $310 million.[21] DRA's total cost estimate is approximately $471 million as opposed to PG&E's estimate of $575 million. With the evidence before us, we have little choice but to adopt PG&E's estimates of meter device costs. It is unfortunate that non-disclosure barriers prevents any detailed analysis of DRA's recommendation, but without some idea of what the differences are and whether those differences appropriately consider PG&E's situation and needs, we cannot adopt costs that are so different from that proposed by PG&E.

PG&E's estimate is based on costs derived from an RFP process. Based on responses to that process, PG&E conducted an evaluation of the integrated meter devices from certain vendors to help identify vendor and meter device technologies best suited to serve PG&E and its customers. According to PG&E, the vendors selected for further consideration were selected following a rigorous vendor selection process in order to ensure that the vendor ultimately selected has sufficient resources, credibility, and expertise to supply the necessary equipment and services to complete their work within an appropriate timeframe and budget. For a project of this magnitude such evaluation is prudent. However such evaluation cannot be performed with respect to the vendors and devices related to DRA's projected costs, due to the non-disclosure restrictions.

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[21] The number for DRA incorporates PG&E's $61.1 million adjustment to baseline costs that was reflected in its May 2008 supplemental testimony. The total baseline costs for end-point technologies from PG&E's original AMI decision is approximately $265 million. For comparison purposes, PG&E's number does not include HAN connectivity costs or HAN Upgrade costs other than the HAN gateway device itself and does include new meter devices associated with the Kern County electromechanical meter upgrade.

DRA's data, which according to DRA shows the average of the bids considered by its consultant as being in the same general range as PG&E's proposed cost, provides some additional assurance that PG&E's RFP approach is reasonable.

It would be inappropriate to impose DRA's proposed costs on PG&E without assurance that the related meter devices provide the necessary functions, without assurance that the vendors are capable of providing the equipment when needed, and without knowledge of the type of warranties that are associated with the costs.

For these reasons, we adopt PG&E's estimate of the incremental costs for meter devices. However, we will require that PG&E provide quarterly reports on the implementation progress of the Upgrade to the Commission's Energy Division and any interested parties. PG&E should consult with the Energy to determine what information PG&E should provide.

7.2. HAN Retrofit

As described in PG&E's testimony, the HAN retrofit[22] involves PG&E deploying 288,000 upgraded meters with load limiting switches and upgrading these meters with HAN gateway devices at a later date. PG&E stated that one of the key principles guiding the company during its transition from electromechanical meters under the existing SmartMeter Program to the upgraded meters proposed in this proceeding was the objective of beginning deployment of solid state meters, preferably with load limiting switches and HAN devices, at the earliest strategic point in its deployment schedule. In its May 2008 supplemental testimony, PG&E indicated that it had recently learned that its preferred HAN devices were scheduled to become commercially available in the fourth quarter of 2008. Therefore, PG&E planned to install solid state meters that have a load limiting switch -- but that do not have a HAN device -- during the limited period between the time that PG&E completes the installation of the remaining

[22] The HAN retrofit is also referred to as ubiquitous HAN.

electromechanical meters (e.g., summer 2008) and the time the HAN devices become available. To support real-time pricing, dynamic pricing, and opt-out programs for all customers, PG&E stated it will be necessary for PG&E to then retrofit these above-described solid state meters with HAN devices. PG&E estimated the net cost increase of such a retrofit will be approximately $30 million.

In support of its decision to proceed with the HAN Upgrade, PG&E's consultant, Lechner, performed an analysis of several meter deployment scenarios comparing lost benefits to reduced costs, if PG&E had suspended meter deployment until HAN devices became available. According to PG&E, the analysis indicates that lost benefits exceed reduced costs, and PG&E acted reasonably in moving forward with meter deployment without the HAN devices.

7.2.1. DRA's Position

DRA excludes all costs associated with the HAN retrofit except those directly associated with enhanced functionality. DRA believes that PG&E could have merely suspended the deployment of solid state meters without a HAN device and avoided the additional costs that PG&E includes. DRA also criticizes PG&E's suspension analysis, stating that the cost-benefit analysis is distorted by three problems: (1) it ignores the present value cost savings of delaying the deployment of the subsequent five million meters; (2) it artificially truncates the stream of foregone benefits for all scenarios to 2011; and (3) it includes different numbers of months of foregone benefits for the four scenarios evaluated.

Regarding the first problem, DRA asserts that Lechner ignored the cost savings from delaying the deployment of some five million meters apparently because he did not find them to be important enough to include. According to DRA, the particular studies that led him to this conclusion are not in the record, but, because of this decision, the only endpoint costs Lechner includes in his analysis are those associated with the 288,000 meters, which he then compares with the foregone benefits associated with over five million meters. DRA states that the result is predictable – the benefits dominate the analysis.

The second problem, according to DRA, is that Lechner truncated the period of analysis such that it would end in 2011, in spite of the fact that the benefits persists for the projected 20-year life of the endpoints for all four scenarios he considered. DRA asserts that had Lechner not truncated the benefits streams, the benefits in nominal terms for each of the four scenarios would have been identical. The only difference would have been in the timing of the benefits.

DRA's third problem has to do with Lechner truncating the benefits of all scenarios to the end of 2011, which resulted in a five fewer months being used to calculate the benefits for the five-month scenario relative to the non-suspension scenario. According to DRA, had he allowed the benefits streams to continue for the lifetime of the equipment, the benefit streams for all the scenarios would have included the same number of months. The only difference would be the point in time when they would have occurred.

In response, regarding DRA's allegation that Lechner's analysis ignores the present value cost savings of delaying the deployment of the subsequent five million meters, PG&E states that Lechner specifically considered the cost implications of suspending five million meters and the analytical result was the basis for his conclusion, and cites the following cross-examination:[23]

> DRA Counsel: Mr. Lechner, in your analysis did you include or consider the impact of delaying the cost of deploying 5 million meters?
>
> PG&E witness Lechner: During the course of my analysis and analyzing the implications of the cost, I considered that, whether that would have an impact on the end result.

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[23] 2 RT 271.

> Q: What was your conclusion?
>
> A: The conclusion is … as I refined the model on the cost side by contemplating the time value of money under various different delay scenarios, in conjunction with additional escalation, in conjunction with additional inefficiency costs, in conjunction with the additional costs that would be incurred, each scenario that I looked at had no implications, no impact on the overall result, I drew the conclusion that the cost side of this model really isn't driving the equation. It's the benefits side.

Thus, PG&E asserts that, counter to DRA's allegation that Lechner ignored the cost savings from delaying the deployment of some five million meters apparently because he did not find them to be important enough to include, the record shows that Lechner specifically considered the cost implications of suspending five million meters and the analytical result was the basis for his conclusion. PG&E emphasizes that the only cost "savings" from a suspension scenario are related to the time value of money associated with deferral, and notes that Lechner specifically considered these "savings," but, unlike DRA, Lechner also considered the significant additional costs associated with suspending endpoint deployment.

PG&E states that DRA's second allegation -- that Lechner's analysis "artificially truncates the stream of foregone benefits for all scenarios to 2011" and that this "inflates" the differential between the lost benefits between PG&E's business case and a suspension scenario -- is wrong both in theory and application, with the following explanation:[24]

> From a theory standpoint, Mr. Lechner properly pointed out during cross examination that in doing a comparative analysis between a continued vs. suspended deployment scenario, it is necessary to compare the same period of time. By comparing the stream of benefits generated by continuing deployment with the stream of benefits generated by a suspended deployment over a defined period of time, Mr. Lechner was able to determine the present value of "lost benefits" caused by a delay scenario. As Mr. Lechner also pointed out during cross-examination, extending the

[24] *See* PG&E Opening Brief, pp. 21-22.

> period of time to evaluate lost benefits caused by a suspension scenario does not change the fact that benefits accrue at a faster rate under the continued deployment scenario than they do under a suspension scenario.
>
> From an application standpoint, DRA erroneously attempts to link the benefits associated with meter deployment to the estimated 20-year life of the endpoints and fails to consider the compounding nature of benefits over time. The estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic impact of a deployment suspension scenario. Benefits begin to accrue when an endpoint is installed and activated. A large percentage of the operational benefits created by this endpoint activation are due to PG&E's ability to avoid the labor costs of meter readers on activated SmartMeter routes. When an endpoint reaches the end of its useful life, the meter will be repaired or replaced and the benefit stream will continue, uninterrupted (e.g., PG&E will not re-hire its meter readers at the end of the estimated life of a SmartMeter). This is another reason why it is essential to use the same end date for all scenarios in a comparative analysis of benefit streams.

Regarding DRA's third allegation that Lechner's benefits differential is inflated because he used "five fewer months" to calculate the benefits for the five month suspension scenario than for the non-suspension scenario, PG&E states that DRA misses the point of the comparative analysis. It is the timing of endpoint deployment that drives the magnitude of realized benefits, and suspending deployment of endpoints would delay the realization of benefits that would be obtained under a non-suspension scenario. PG&E states that Lechner's analysis properly modeled the stream of benefits associated with PG&E's endpoint deployment plan without a suspension scenario and compared this to the stream of benefits that would result from suspended deployment plans, and comparing the present value of these various benefits streams provides a clear quantification of the impact of suspension benefits realization.

7.2.2. TURN's Position

It is TURN's position that PG&E could avoid this increased cost if it simply waits to deploy its solid state meters until (a) its preferred HAN technology is commercially available or (b) a final Commission decision on this application. TURN states that PG&E

has chosen to prematurely move ahead with a large number of solid state meters by the end of 2008, even though PG&E intends to scrap or retrofit all of the meters later, requiring at a minimum, a duplicative expensive field visit from a PG&E employee or contractor, and argues that the ratepayers should not be saddled with the cost of PG&E's unreasonable management strategies.

TURN states PG&E' suspension analyses are flawed for many reasons and should be disregarded. First, the analysis was not completed before this application was filed in December 2007, so TURN states it could not have been used to justify the project management decisions. Second, TURN asserts analytical flaws render the analysis useless. According to TURN, a correct analysis would have taken all recorded costs and benefits up to July 2008 and then analyzed a delay (recognizing all recorded costs and benefits) compared to an updated forecast of remaining costs and benefits, something PG&E did not do. In addition, TURN criticizes PG&E's assumption that all meters are activated and providing O&M and demand response benefits in the same month they are installed. TURN notes that PG&E currently has over 534,000 gas meters installed but only 67,000 activated, and there are no demand response benefits currently and PG&E has been installing meters for at least a year and a half.

CCSF states that it agrees with TURN's reasoning for rejecting the HAN retrofit and TURN's position that ratepayers should not have to pay the additional $34.8 million (with risk allowance) requested by PG&E.

In response to TURN, PG&E states that TURN's suggestion that Lechner's analysis should be rejected because it was performed after PG&E's initial Upgrade filing, ignores the record, noting that PG&E witnesses Corey and Meadows both testified that PG&E had considered the potential costs and benefits of delaying deployment while PG&E evaluated the emerging technology. When PG&E submitted its Application in December 2007, it was in the middle of negotiations with its Upgrade vendors and was continuing to refine its specific technology selections and deployment alternatives. According to PG&E, this was an appropriate time to analyze the detailed implications of various deployment scenarios, including potential suspension of endpoint deployment depending on the availability of PG&E's preferred HAN device identified as a result of the ongoing vendor bidding. PG&E further states that its May 2008 update to its Upgrade Application included the results of its ongoing vendor negotiations and that, had the results of Lechner's analysis been different and concluded a suspension scenario was indeed preferable to continuing deployment, PG&E would have included such a result in its May update.

PG&E states TURN's suggestion that "[a] correct analysis would have taken all recorded costs and benefits up to July 2008 and then analyzed a delay … compared to an updated forecast of remaining costs and benefits" ignores the fact that the costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the comparative analysis because they are exactly the same for all scenarios being compared.

With respect to TURN's argument that Lechner's assumption regarding the timing of benefits relative to endpoint installation is wrong, PG&E states that the identification of benefits with endpoints in the month they are installed was a simplifying assumption applied to each scenario. While this does not calculate the precise timing of benefits realization, it is an appropriate approach to compare the benefit stream of a continued deployment scenario with various suspension scenarios, provided the assumption is consistent among the scenarios, which according to PG&E, it was.

7.2.3. Discussion

PG&E's suspension analysis of the HAN Upgrade appears reasonable. Its consultant compared lost benefits due to suspension to reduction in project costs resulting from the suspension relative to the base case. Relative to the base case, the only cost that would not be reduced due to a suspension is the cost of the HAN gateway device. All of the other costs are associated with the retrofit of the meter. PG&E's consultant added the cost of the HAN device to the suspension costs[25] to quantify the total costs that should be subtracted from the reduced costs due to the suspension before being compared, on a PVRR basis, to the lost benefits due to the suspension. In all three suspension scenarios (three, four and five-month suspensions), the analyses showed the lost benefits exceeding the net reduced costs.

We have evaluated the criticisms made by TURN and DRA with respect to PG&E's consultant's suspension analyses along with PG&E's responses. In general, we find that PG&E has adequately explained and defended the analyses, and we are comfortable in using the analyses as a basis for determining the reasonableness of PG&E's actions.

In particular, we agree that the estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic impact of a deployment scenario. If deployment is suspended for five months, benefits for those five months are lost. At any point in time beyond 2011, when the base and suspension scenario are compared, the five-month suspension scenario will have five months fewer benefits. That is simply because the benefits go on indefinitely and do not end when the meter has been in place for 20 years and is retired and replaced or is refurbished.[26] We also agree that the costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the comparative analysis because they would be the same for all scenarios being compared.

[25] Suspension costs include the monthly suspension costs that PG&E is contractually obligated to pay for suspending the installation contract, the monthly costs for suspending PG&E project management office operations, and the labor escalation costs PG&E would incur by installing the meters with HAN devices months later than originally planned.

[26] While any future AMI system may differ from the upgraded SmartMeter Program, the current benefits of the SmartMeter Program will likely be obtainable through any future new systems and will continue.

Lechner's conclusion that the cost of the 5 million meters had no impact on the overall results in his analysis was based on his examination of his model outputs and appears reasonable. DRA had access to Lechner's model and has not indicated that the outputs that Lechner relied on are erroneous in any way.

Also, PG&E has provided sufficient explanation as to why its consultant's suspension analysis was performed after the filing of the application. What is important is that it was performed before this aspect of meter deployment began, and was thus available for PG&E's project management to use in determining whether or not to go forward.

While PG&E's decision to proceed with the HAN retrofit appears to be reasonable, the magnitude of the retrofit cost estimate ($32,026,000 plus a 10% risk based allowance) has not been fully supported and justified. There is little support for PG&E's quantification of the number of meters that would necessarily be installed without a HAN device. Also, the record does not include detail and substantiation of all of the various cost components of the retrofit. For instance, while the costs include that necessary to physically retrofit a meter with a HAN device, there is no detail as to what that particular cost is, what it was based on, and why it is reasonable. Also, it is not clear whether the communication module that is replaced has any salvage value and if so whether that was factored into the costs. To account for uncertainties and attempt to ensure that ratepayers only fund appropriate costs, we will reduce adopted funding for the HAN retrofit by $5,500,000 (plus $550,000 for the related risk based allowance).

7.3. Electromechanical Meter Retrofit

At the time of the application filing, PG&E had already procured 230,000 electromechanical meters intended for its Kern County region. Approximately 123,000 of these meters had already been installed and the rest were to be installed by mid-2008. Considering the availability of the improved meter devices and the continued ability to achieve the benefits of SmartMeter Program deployment, PG&E believed it would be reasonable to make the transition from electromechanical meters to solid state meters as early as practicable to minimize the potential retrofit of installed electromechanical meters with upgraded meter devices pending the Commission's approval of PG&E's request in this application. PG&E decide the time to make the transition was after completing deployment of the Kern region.

Once all customers have received an advanced meter (i.e., in 2011), PG&E proposes to upgrade the estimated 230,000 electromechanical meters with the new solid state meters so that all of PG&E's electric customers can participate in the new service offerings and increased functionality available with the upgraded meters. PG&E estimates that it will require approximately six months to upgrade these electromechanical meters installed prior to the SmartMeter Program Upgrade. PG&E has forecast $37,312,000 in costs relating to the retrofit of meters deployed in the Kern region. These costs would provide labor and material sufficient to replace the 230,000 meters deployed in the Kern region without a HAN device or load limiting switch, with a complete advanced solid state meter, integrated load limiting switch and a HAN device.

7.3.1. Positions of DRA and TURN

DRA states that it is supportive of the enhanced functionality associated with the HAN and the integrated service switch, as well as the advanced Tier 1 solid-state meter required for both these functions. Thus, DRA includes these costs in its business case even for the electromechanical meter retrofit. It also includes the labor costs for the Kern retrofit because a second visit to these meters would have been required anyway to install this new functionality. Unlike PG&E, DRA adds that it did not include the cost of new communications modules and network costs for the Kern retrofit, because it believes that the choice of the DCSI system was questionable to begin with.

DRA's argument for disallowing most of the Kern County retrofit costs is not based on the idea that the Kern County deployment could have been delayed, it is based rather on DRA's belief that PG&E came to the Commission prematurely with its original application, A.05-06-028, in the first place. DRA states that its support for that application must be qualified, in that such support was based on representations that

PG&E made that have turned out to be wrong. Transcript evidence shows that DRA witness Abbott had expressed concerns to PG&E at a meeting in December 2005 about whether the DCSI system would have sufficient bandwidth to handle the signals in an urban area with high density. He was assured by PG&E that it had developed workarounds to this problem. Therefore, he gave PG&E the benefit of the doubt, and in his testimony in A.05-06-028, stated that PG&E's technology choice is "generally reasonable." According to DRA, representations also had been made by PG&E about the ability of the DCSI technology to support the HAN technology, and these did not pan out either. It is because of PG&E's decision to "jump the gun" that DRA does not even include the cost of the base meter in the Kern retrofit.

TURN recommends that the Commission disallow all the costs related to the electromechanical meters in the Kern region by (1) disallowing the $41.03 million requested in this application[27] to retrofit the installed electromechanical meters; and (2) removing $23.2 million from PG&E's original AMI budget, thus making it less possible for PG&E to indirectly recover some of these costs through contingency allowances. TURN recommends the removal of the meter costs from the original AMI budget, because they were stranded by poor management decisions regardless of the outcome of this Upgrade application.

TURN states that despite the fact that PG&E filed a request for authorization of over a half a billion dollars to "upgrade" its AMI project, it persisted in installing meters in the Kern region that it knew it would strand in only four years. While PG&E claims that it did not finally decide it would change its AMI technology until the date that it filed this application in December of 2007,[28] TURN argues that PG&E indicated that it began the process of evaluating solid state meters, integrated load limiting disconnect switches,

[27] This number includes the risk based allowance associated with the electromechanical meter retrofit.

[28] Exhibit 208, p. 12.

and the availability of home area network technologies in early 2007,[29] and, by May 2007, PG&E indicated that it was interested enough in the new technologies to adjust its meter procurement plan and tell its electromechanical meter supplier that it intended on terminating the contract for buying electromechanical meters.[30] According to TURN, PG&E was not forced to strand this investment. It proactively chose to do so and did so while requesting additional funds to fully deploy an entirely different technology. In TURN's opinion, PG&E's decision to continue installation of electromechanical meters in the Kern region was unreasonable and imprudent, and the Commission should not insulate PG&E from the consequences of its decisions.

In response, PG&E expressed its understanding that DRA would allow about $18.8 million of the requested costs, by adding $6.3 million in labor costs to about $12.5 million for the incremental costs of an advanced solid state meter, the integrated load limiting switch and the HAN device.[31] DRA would not allow funding for the "base" cost of the meter itself or the communications module that would need to be replaced. PG&E further understands that TURN estimates the installation costs of the Kern deployment for its proposed disallowance of $23.2 million.

It appears to PG&E that, despite the proposed disallowances, both DRA and TURN want the retrofit to be performed. According to PG&E, what intervenors debate -- and the issue on which their proposed disallowances depends --is whether PG&E should

[29] Exhibit 209, Attachment G.

[30] *Id.*

[31] According to PG&E's opening brief, the costs of the Electromechanical Meter Upgrade of approximately $37.3 million (confidential Workpapers Supporting Exhibit 7, WP A-2, line 7) includes approximately $12.5 million of incremental equipment costs. This includes $4.8 million of incremental costs associated with advanced endpoint functionality (230,000 x ($58 - $37)), approximately $5.2 million of costs associated with the integrated load limiting switch (230,000 x $23), and approximately $2.5 million of costs associated with the HAN Gateway Device (230,000 x $11), for the endpoints located in PG&E's Kern Division (Confidential Workpapers Supporting Exhibit (PG&E-7), WP 1-50).

have installed (in the first instance) the DCSI power line carrier (PLC) equipment on electromechanical meters in Kern. For the three reasons described below, PG&E asserts that it was right to do so.

First, PG&E indicates that its deployment of the electromechanical meters in Kern followed the directives of D.06-07-027 to the letter and was strongly supported by DRA in that case. PG&E points out that (1) the meters deployed include the technologies approved in D.06-07-027, (2) no party has alleged that PG&E has somehow strayed from the letter or intent of D.06-07-027 in deploying these meters, and (3) the deployment has been successful and the meters are working as intended, generating operational benefits as meters are activated.

Second, PG&E states that the argument that PG&E should have delayed installing the Kern meters, as an alternative to incurring the proposed retrofit costs has no merit, because it ignores the evidence in the record that continued deployment was beneficial for ratepayers. PG&E explains that when it became apparent the Upgrade technology might be becoming commercially feasible, PG&E considered a short-term suspension of electric meter deployment, but determined this would not be in the best interest of its customers. PG&E concluded that delaying implementation would serve to increase overall costs as vendor commitments had already been made and a suspension would result in further delays to the benefits.

Third, regarding DRA and TURN suggestions that if PG&E had installed solid state meters in Kern, then a retrofit to accommodate the HAN device would not be necessary,[32] PG&E states that a retrofit would still be necessary and the original deployment would have been more costly. This is because the use of electromechanical meters in the original deployment plan resulted in approximately $36 million in cost savings when compared to using basic solid state meters. PG&E also states that these basic solid state meters that were available for deployment at the time of the original AMI case would not support a HAN device and thus would need to be replaced now anyway, a point that DRA conceded during hearings.[33]

7.3.2. Discussion

Electromechanical meters have been deployed in the Kern region, and, as a result of PG&E's Upgrade request, the electromechanical meter costs will become stranded once these meters have been replaced. We see the fundamental issue to be whether these stranded costs should be addressed as part of the costs of the original AMI program or as

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[32] PG&E cites DRA, Exhibit 108, Exhibit 2, Chapter 3, p. 3-3, line 11 and TURN, Exhibit 208, pp. 12-13 as the basis of the suggestions.

[33] DRA, Abbott, 4 RT 463.

part of the costs of the Upgrade. As discussed further in this decision,[34] we determine that the stranded costs related to the electromechanical meters should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project. Therefore, for purposes of this proceeding, we need not determine whether PG&E should or should not have deployed electromechanical meters in the Kern region, or whether PG&E came prematurely to the Commission with its original AMI application.

Our result is similar to that of DRA in that we include costs for the upgraded system, but exclude costs related to the original meter and communications device. Based on PG&E's representation of DRA's recommended cost for the electromechanical meter retrofit, we will adopt, as reasonable, an amount of $18.8 million for that purpose.

Because of the manner in which this issue is resolved, it would not be appropriate to remove $23.2 million from the original AMI budget as proposed by TURN. It appears that amount represents the stranded costs that should be absorbed through the risk based allowance or contingency.

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[34] *See* Section 7.12.2.

7.4. HAN Connectivity

PG&E states that one challenge in effectively deploying HAN technologies is the variety in configuration of customers' premises. In some residences, the signal from the HAN device may need to travel long distances because of a meter located away from the home. Even for homes with attached meters, it is possible that appliances and devices such as thermostats, pool pumps or water heaters may be placed in locations that are difficult for the signal to reach. For example, water heaters may be located in basements or garages and pool pumps could be in external structures.

According to PG&E, currently, there are two predominate HAN gateway technologies in the marketplace, PLC technology and RF technology. Each of these technologies has strengths and weaknesses in dealing with the challenges created by the diversity of structure types and distances. For example, PLC technology is better at traveling long distances and has the ability to communicate with some devices that are not plugged into an electrical outlet such as a thermostat, while RF technology is better able to reach devices that may not be able to receive PLC communications.

To compensate for the variations in functionality of different HAN gateway technologies and to take advantage of the best available solutions, PG&E proposes a combined RF and PLC solution. This combination of approaches will serve more types of homes than one approach or the other. PG&E would likely deploy a PLC-based solution to customers living in multi-dwelling units. This is because the HAN signal travels into the home through the electric wiring instead of via radio signal that can frequently be blocked or attenuated. Therefore, for the HAN gateway, PG&E proposes to use a combination of Homeplug (PLC) and Zigbee (RF) devices – whereby the PLC solution would be used to enhance reliable connectivity for large, multi-storied and multi-unit dwellings, and the RF solution would likely be deployed to other types of residential electric customers.

Based on ongoing research and discussions with DRA, PG&E believes that it is prudent to deliver a standardized and common RF based HAN signal into all customers' premises.[35] According to PG&E, this means that for the approximately 40% of premises that were expected to receive a Homeplug device, all of those premises will require some type of bridging or augmentation device to bring an effective signal from the meter location to an interior wall of the customer's premises.

However, at the present time, there are still a number of uncertainties regarding the best approach to extend the connectivity of the HAN devices at the meter to an interior wall of a customer's premise. PG&E states that, although much work in the industry and in standards development is occurring, there is not yet a standard approach to reliably deliver HAN connectivity on a universal basis, including translation or bridging devices. PG&E and the others in the industry are currently evaluating several approaches to address this challenge. Therefore, while it is premature to settle on a specific solution and lock in to a defined approach for an extended period of time, PG&E believes its recommendation is appropriate given the stated goals related to the home area network and reflects a thoughtful consideration of the known technical challenges of each HAN technology and the state and direction of the HAN standards and industry.

PG&E has developed its estimate of costs to extend HAN functionality from the electric meter location to an interior wall of a customer's premises using the following assumptions:

(a) 40% of customers' premises with installed Smart Meters will require a bridging, translation or another augmentation device to bring RF connectivity to an interior wall of the customer's premises.

(b) During the period covered by the revenue requirement request in this case, 15% of the above-described customers' premises will require a bridging, translation or another augmentation device to bring RF connectivity to an interior wall of the customer's premises during the

[35] For example, regardless of what technical solution PG&E uses for a particular HAN device in the meter (RF or power-line based), the customer would be provided a single or common RF based protocol once the signal is made available within the customer's premises.

project period, considering customers' demand for HAN functionality. The remaining customers would obtain the bridging, translation or another augmentation device in later years.

(c) PG&E set an allowance of $50 for each bridging, translation or other augmentation device for either the provision of such a device or to provide a rebate to customers seeking to install their own devices.

By doing the above, PG&E states that it would deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises. However PG&E cautions that no utility can guarantee that the HAN signal would be available throughout all areas of the customer's premises or property. Under PG&E's proposal, additional signal enhancements within a customer's premises to extend the connectivity of the HAN device from an interior wall to other locations within the premises would be the responsibility of the customer or the provider of the HAN enabled device with which the customer desires to establish a connection.

For HAN connectivity, PG&E seeks $16,891,000 in incremental costs. In total, the HAN connectivity related PVRR amounts to $59,123,000 under PG&E's proposal.

7.4.1. DRA's Position

DRA recommends Homeplug deployment be set at 30% rather than the 40% requested by PG&E. According to DRA, while PG&E's Homeplug estimate is based on the "nature of dwelling types in its service area," that is, the ratio of single family homes to multiple family homes, it does not take into account that some multiple family homes are duplexes that are not much larger than a single family home. DRA states that PG&E has provided no data on the typical broadcast footprint (in feet of dispersion) of the Zigbee interface, and PG&E has adopted the most conservative assumption possible, that is, that all multiple family homes will require a HomePlug interface. DRA likens this to asking for an extra cushion on top of its normal risk allowance.

In response, PG&E states that the net effect of DRA's recommendation would be to reduce PG&E's costs by approximately $4 million[36] and argues that DRA's recommendation is not supported by any analysis or documentation and is made solely as a way of reducing project costs. PG&E cites the following from the evidentiary hearing transcript:[37]

> PG&E Counsel: What does DRA want to do?
>
> DRA Witness Levesque: 70/30. [Meaning 70% ZigBee and 30% HomePlug.]
>
> Q: Did you do any analysis of PG&E's system to come up with that percentage?
>
> A: The foundation for that change was in one sentence of what if it were 70/30. And the reliance upon would 70/30 make sense was based entirely on subjective opinion of number of households, number of apartments and small apartment buildings the size of a population of the City of San Francisco. And that was in a communication with DRA that gave me that information.
>
> I have no supporting, specific documentation for the 70/30. And I don't know if there is empirical evidence in the marketplace today as to whether HAN will produce 62/38 or 70/30.
>
> Q: When you say what-if scenario, was that an effort to get the price down?
>
> A: It was an effort to understand the magnitude of what a change would be of -- if HAN were 10% more effective, what that might do for pricing.

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36 By changing the percentage split of ZigBee/HomePlug from 60%/40% to 70%/30%, the weighted average cost of the HAN Gateway Devices would be reduced by $0.75 and result in a decrease of approximately $4 million.

37 Reporter's Transcript, p. 548, line 13 to p. 549, line 9.

> Q: The effect of raising the percentage of [ZigBee] effectively reduces the amount of money PG&E gets; right?
>
> A: That is correct.

Accordingly, PG&E asserts that DRA's recommendation has no proper evidentiary basis, PG&E's proposal for a 60/40 split in the deployment of ZigBee and HomePlug devices is the only proposal on record with a proper evidentiary basis, and PG&E's proposal is the most appropriate for promoting HAN receptivity for customers.

7.4.2. TURN's Position

TURN argues that the request should be rejected, because extended HAN connectivity costs are directly related to PCTs associated with PG&E's Title 24 program, and PCTs will not be incorporated into the next round of Title 24 building standards. PG&E will not be recruiting customers until 2013, outside the forecast period for this application. Therefore, TURN asserts that HAN connectivity costs should also be excluded from the program.

TURN also argues that HAN bridging device technology is not well known at this time, and is in the infant stage of development. According to TURN, the Commission should therefore not authorize this request and expose ratepayers to further risk of stranded technology and costs. TURN also questions the efficacy of this type of investment given that customers in multi-family dwellings are the least likely customers to be able to take advantage of HAN to alter energy usage since they rarely have the ability to install HAN-enabled appliances. Furthermore, because these customers generally have a lower energy usage than residential customers that live in single-family dwellings, TURN asserts they have less energy to conserve, reduce, or shift and are therefore poor candidates for providing demand response.

In response to TURN, PG&E states that regardless of whether a landlord or tenant owns an appliance, the person who pays the energy bill – typically the tenant – has the incentive to reduce his or her energy costs through the information available from the

HAN repeater device. According to PG&E, studies have shown that tenants may have even more to gain from the information available from the HAN. This is because such tenants are deprived of the ability to control their energy use through hardware choices and their best means of control is through their use patterns and the information available through the HAN.

7.4.3. Discussion

First of all, we are in agreement with PG&E's general direction in attempting to deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises. To do this, it is reasonable to use both RF and PLC technologies as proposed by PG&E.

With regard to whether the HomePlug or PLC technology should be applied to 30% of the residences as proposed by DRA or 40% as proposed by PG&E, we will adopt PG&E's 40% proposal. The basis for DRA's proposal stems from a hypothetical analysis involving cost sensitivity based on a 30% assumption. There is no evidence as to the reasonableness of using 30% to reflect what might actually occur.

With respect to TURN's argument that HAN connectivity costs should be excluded because PG&E will not be recruiting Title 24 PCT customers until 2013, we decline to do so, because HAN connectivity relates to not only PCTs but also to other devices such as in home displays. In PG&E's supplemental testimony, the proposal for HAN connectivity was expanded to all customers, not just to Title 24 PCT customers.[38]

Regarding TURN's argument that customers in multi-family dwellings are the least likely customers to be able to take advantage of HAN to alter energy usage and PG&E's response, the determination of who will use the HAN technology, and to what extent they will use it, is fairly subjective at this point. From a policy perspective, we

[38] *See* Exhibit 7, p. 8.

feel it is important that customers that wish to use the technology are, to the most reasonable extent possible, able to do so.

We are however somewhat hesitant to authorize additional funds to provide a single or common RF based protocol once the signal is made available within the customer's premises. As PG&E itself acknowledges there is not yet a standard approach to reliably deliver HAN connectivity on a universal basis, including translation or bridging devices. TURN argues ratepayers should not be exposed to the risk of stranded technology and costs, and PG&E's request regarding HAN connectivity should be rejected. On the other hand, we believe HAN connectivity on a universal basis makes sense for such purposes as advancing and developing the HAN technology in an efficient manner. With the expectation that it may be necessary in some form, we will authorize PG&E's HAN connectivity request. We expect PG&E to adapt the implementation of HAN connectivity over time consistent with approaches and solutions that are being addressed and developed, currently and in the future, by those in the industry that are addressing these issues. It is PG&E's responsibility to achieve HAN connectivity in the most cost effective manner within the costs and risk based allowances provided by this decision. PG&E should understand that we will be extremely reluctant to saddle ratepayers with stranded assets and costs associated with any cost overruns related to HAN connectivity.

7.5. Information Technology

PG&E estimates that it will incur incremental information technology (IT) costs resulting from the additional scope functionality of the SmartMeter Program Upgrade. These include IT costs to support the PTR Program, HAN functionality, the AC Program, the Load Limiting Functionality and IT project management. Briefly,

- In order to accommodate its proposed PTR program, PG&E states that it will be necessary to modify its Customer Care and Billing (CC&B) and Customer Service On-Line (CSOL) systems. To estimate the cost of these efforts, PG&E used its standard four-phase IT model: pre-build, develop, test, and support. The estimated labor cost of this incremental scope increase is $4 million, which is based on PG&E's average, daily, internal and external labor rate of $1,200. PG&E expects to incur these PTR-related costs from mid-2008 to mid-2009.

- To support the HAN functionality, PG&E proposes to establish reliable and secure two-way communication between PG&E's network management systems and the HAN gateway devices. It will also confirm the ability to address an Internet Protocol (IP) addressable device behind the meter and receive a response. PG&E anticipates it will perform the HAN infrastructure and integration work in 2009 at an estimated cost of $23.1 million, which includes $4.6 million of non-labor costs and $18.5 million of labor costs.

- Starting in 2013, PG&E proposes to use HAN capability to provide AC Program functionality for Title 24 compliant programmable communicating thermostats (PCT) as part of the SmartMeter Program Upgrade, in order to enhance and expand PG&E's current SmartAC Program. PG&E states that operating the AC Program on the HAN network (likely in parallel to the current vendor-provided SmartAC Program) for all Title 24 PCTs requires PG&E to: (1) provide in-house services similar to those currently performed by vendors for the SmartAC Program (i.e., program enrollment, deployment, customer service, and load/event management); (2) utilize the two-way AMI network/HAN; and (3) integrate a PG&E-hosted load management system with the AMI infrastructure. To estimate the costs of using the HAN network to communicate with new PCTs, PG&E reviewed the program's current business and technical requirements and estimated the software and labor resource needs required to build the system internally. PG&E anticipates it will incur these incremental AC Program costs in 2011. PG&E estimates the incremental cost of the upgrade to be $14.8 million, which includes $2 million of software costs and $12.8 million of labor costs.

- PG&E estimates it will incur additional costs to integrate the load limiting connect/disconnect switches for all its single phase residential meters with a maximum of 200 amps. Modifications and interface changes will be required to create new credit/collection templates, start/stop algorithms, and partial Load Limiting Functionality. To estimate the cost of these efforts, PG&E used its standard four-phase IT model: pre-build, develop, test, and support. The estimated labor cost of this incremental scope increase is $3.7 million, which is based on

PG&E's average, daily, internal and external labor rate of $1,200. PG&E expects to incur these costs from mid-2008 to mid-2009.

ffi PG&E states the Upgrade will require additional IT project management efforts to support the additional IT work discussed above. PG&E anticipates it will need three additional FTEs from mid-2008 to mid-2011 at an estimated total cost of $2.8 million.

7.5.1. DRA's Position

As discussed further on in this decision, DRA opposes consideration of the PTR program as part of the Upgrade, because DRA feels the PTR program could be implemented in conjunction with PG&E's originally authorized AMI system. For this reason, DRA excludes all PTR benefits and the majority of PTR related costs including $4 million (PVRR) in IT costs associated with the PTR program. DRA states that, if the PTR program is funded in another proceeding, the associated IT cost could be considered there.

DRA also notes that an unnecessary duplication of IT costs has occurred because of PG&E's choice to implement a communication system as part of its SmartAC program that is duplicative of the HAN communication system. However, because DRA is supportive of the HAN technology, it did not exclude the IT costs associated with HAN communication.

With respect to DRA's exclusion of $4.0 million in PTR related IT costs, PG&E states that the adjustment is a corollary to DRA's position that benefits for the PTR program should also be excluded from the cost/benefit analysis for the Upgrade, and accordingly, if the benefits of the PTR program are included – as PG&E believes they should be – the IT costs for the PTR program should be included as well.

7.5.2. TURN's Position

Similar to DRA, TURN asserts that PG&E's original AMI technology was capable of implementing PTR on a wide scale, and reduces both costs and benefits as they relate to the Upgrade. This includes exclusion of the $4.0 million in IT costs for the PTR program.

TURN also excludes $14.8 million in IT costs requested by PG&E in conjunction with the proposed use of the HAN functionality to communicate with Title 24 building standard compliant PCTs. TURN states that PG&E itself has withdrawn other costs associated with the Title 24 PCT program. Specifically, PG&E assumed in the application that the CEC's proposed Title 24 building standards would begin in 2009, but the CEC later postponed its recommendation. As indicated in its supplemental testimony, PG&E now assumes the standard will be implemented in 2012 and that PG&E will begin recruiting customers in 2013. TURN states that PG&E reduced its Title 24 PCT program cost request by $5.0 million[39] because 2013, the year PG&E begins the program, is outside of the forecast period for this application and argues that the Commission should similarly reduce PG&E's request for the related IT costs.

TURN states that PG&E's current Smart AC Program is the result of a settlement with PG&E, DRA, and TURN that was adopted by the Commission in D.08-02-009. That settlement provided PG&E with sufficient funds to implement a 305 MW direct load control program by 2011. The settlement directs PG&E to come back to the Commission in the second quarter of 2009 with an additional application to extend the program to 2020 - after PG&E has completed and reported certain measurement and evaluation studies required in that settlement. According to TURN, any funds used to supplement the program or change recommendations to that program are supposed to be contained in the application PG&E is directed to file with the Commission in the second quarter of 2009. TURN states that the Commission should require that PG&E honor its end of the TURN/DRA/PG&E settlement and reject any costs for the Smart AC program that conflict with that settlement.

Finally, TURN asserts that PG&E requests ratepayer funds to duplicate processes that it readily admits are already being provided by its vendors. As stated in its application, PG&E wants to "provide in-house services similar to those currently performed by vendors for the Smart AC Program" and operate the program "in parallel to the current vendor provided" program. According to TURN, this is operating a redundant program and a wasteful use of ratepayer funds.

In response, with respect to TURN's Title 24 PCT related adjustment, PG&E states that TURN's primary argument, that since PG&E has delayed incurring approximately $5 million in administration and marketing costs associated with the Title 24 PCT program until 2013 or later -- due to the delay in the expected date of the new regulations from the CEC -- so too the IT costs should be removed, has no merit. According to PG&E, the administration and marketing costs associated with the A/C program are distinct from the IT costs. They are for different purposes and are to be expended at different times. PG&E states that under its proposal, the IT work for the A/C program would be performed in 2011, which is still prudent due to the fact that the CEC Title 24 regulations are now expected to be implemented in 2012.

Regarding TURN's other arguments on this issue, PG&E states that first, there is no conflict with the SmartAC settlement, in that, at the time of the settlement, PG&E had notified parties of the possibility that it might file an upgrade to its SmartMeter Program and the settlement expressly envisioned this fact. On this point, the Commission explained,

> [T] he settlement requires PG&E to analyze how to fully integrate the AC Program with its AMI. Integrating the AC Program with AMI will likely increase the value of both programs and expand opportunities for customers to engage in demand response. Therefore, 90 days after the Commission acts on PG&E's pending AMI application (A.07-12-009), PG&E should

[39] Reduced costs are related to program administration, marketing, customer incentives and the call center.

provide a report to Energy Division, DRA and TURN explaining how PG&E intends to integrate the AC Program with AMI.[40]

PG&E argues it is disingenuous for TURN to suggest that there is conflict with the settlement when the settlement itself expressly envisioned that the AC program could be integrated with the Upgrade. PG&E adds that integration of the AC Program with AMI is what this IT expenditure is designed to do and the costs are neither redundant nor wasteful.

7.5.3. CCSF's Position

CCSF states that PG&E may well have underestimated the true cost of the Upgrade. While the hardware to be installed is the most visible element of PG&E's upgrade, it is common practice in joint development efforts of this kind that hardware engineering often leads software engineering. According to CCSF, many of PG&E's chosen hardware components reflect relatively early stage technology, and some of these components do not yet have software necessary to drive them, or to coordinate their individual functions into the larger web of grid and data management systems. To CCSF, this absence of the necessary software suggests that there will likely be significant systems integration challenges, the complexity and cost of which PG&E may well have underestimated. CCSF is concerned, therefore, that PG&E will at a later date seek to recover even more than the nearly $3 billion the Commission will have approved if this upgrade is authorized.

In response, PG&E states that CCSF makes no acknowledgement of the substantial amount of testimony that PG&E has submitted in the area of IT, which addresses not only the IT hardware, but also the software and system integration needs associated with the Upgrade. PG&E states that it understands and has already articulated the types of risks that CCSF purports to have discovered.

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[40] D.08-02-009, p. 13.

7.5.4. Discussion

As discussed further in this decision, we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade.[41] For that reason, it is also appropriate to include the $4.0 million in IT costs related to the PTR program in rates, as requested by PG&E.

Regarding TURN's proposed adjustment for Title 24 PCT related IT costs, PG&E's argument -- that assigning the costs to 2011 is still reasonable because the CEC Title 24 regulations are now expected to be implemented in 2012 -- is not persuasive. In its application filing, PG&E proposed to spend $6,728,000 in 2010 and $8,105,000 in 2011.[42] Also, it expected to begin recruiting AC customers starting in 2011 and estimated the number of customers for that year to be 16,000 with increasing amounts thereafter (e.g., 47,000 new customers in 2012).[43] In its supplemental testimony, PG&E indicates that it now expects to begin recruiting AC customers in 2013 and estimates the number of customers for that year to be 18,000 with increasing amounts thereafter (e.g., 52,000 new customers in 2014).[44]

PG&E has provided no specific reasons to justify why the IT related costs need to be incurred prior to or in 2011 and why they cannot be shifted commensurate with when the expected recruitment of Title 24 PCT customers is expected to begin. Without such justification, we conclude it is reasonable to shift the costs. We will do so by shifting these costs to 2013 and 2014, principally to remove such cost recovery from this decision. There is significant uncertainty as to when this program will begin,[45] and we prefer not to authorize related costs at this time. The Title 24 PCT program costs have

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[41] *See* Section 10.2.4.

[42] Exhibit 3-4W, p. WP 4-1.

[43] Exhibit 3-5W, p. WP 5-3.

[44] Exhibit 7-W, p. WP 1-71.

[45] *See* Section 10.4.3.

already been moved by PG&E to 2013, outside the timeframe for cost recovery authorized by this decision. Those costs will have to be recovered in a separate proceeding. PG&E should seek recovery of the related IT costs at the same time.

We do agree with PG&E regarding TURN's allegations of conflicts with the SmartAC program. It is clear that, in D.08-02-009, the Commission expected the SmartAC program would be integrated with the Upgrade. Also, in that decision, the Commission welcomed PG&E's commitment to incorporate Title 24-compliant PCTs into its project and expressed a concern regarding the settlement's 40% limitation on PCT installations.[46] Further in this decision, we address issues related to the inclusion of the Title 24 PCT program in determining costs and benefits associated with the Upgrade.

Finally, we understand CCSF's concerns regarding what may be significant systems integration challenges. However, while nothing is certain, we feel that PG&E's IT proposal is a reasonable means for overcoming any related problems. This is consistent with our authorization of the same advanced metering technologies, with the same integration challenges, for SDG&E and SCE.

7.6. Title 24 PCT Program Costs

PG&E explains that customers with Title 24 compliant PCTs will need to be identified and recruited for participation in the SmartAC Program and there are costs associated with that activity.[47] In addition, the initiative will be reaching out to customers with existing air-conditioning systems for an early change out of the thermostat with a Title 24 compliant PCT. Administrative costs and minor other costs for software and call center support are also included in incremental costs for the program.

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[46] *See* D.08-02-009, pp.13-14.

[47] A description of the PCT program and the associated benefits is provided in Section 10.4 of this decision.

Some of the outreach activities considered by PG&E include using new customer connect records for identification of likely new construction sites and purchasing permit records to target market to permitted retrofits. Customer acquisition costs of $53 per participant and $25 sign-up incentives are based on the current SmartAC Program estimates.

Due to PG&E's revised assumed timing of the Title 24 PCT program from 2009 to 2012, costs will occur outside of the time period that PG&E is requesting the related rates as part of this application. For costs through 2030, PG&E estimates costs with a PVRR of $37,906,000.

DRA and TURN have not forecasted the PVRR of any Title 24 PCT program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither Title 24 PCT program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade. As discussed elsewhere in this decision, we have included the benefits of the Title 24 PCT program in evaluating the cost effectiveness of the Upgrade. For that reason, it is also appropriate to include an estimate of the costs through 2030 on a PVRR basis for use in the cost effectiveness analysis. However, consistent with our adjustments for reduced participation to the expected benefits of the program, as discussed in Section 10.4.3 of this decision, we reduce the costs by related marketing and incentive amounts. We adopt Title 24 PCT program costs of $26,174,000 on a PVRR basis, as opposed to PG&E's estimate of $37,906,000.

7.7. Peak Time Rebate Program Costs

The PTR program[48] does not require customers to enroll, however awareness of a critical peak event (the day and time period that PTR as well as CPP will be in effect) is

[48] Descriptions of the PTR program and PTR benefits are provided in Sections 10.1 and 10.2 of this decision.

critical to achieve both customer bill rebates and DR resources. PG&E estimates that approximately 50% of residential customers will need to be aware of critical peak events in order to achieve anticipated PTR benefits. According to PG&E, awareness is not an indication of a committed effort. Instead, it provides a proxy for "participation" in the determination of average benefits. PG&E has developed a general strategy for an estimated $7.5 million annual marketing campaign to achieve an average of 50% residential awareness rate of an event without any enabling technology. The media strategy calls for two phases to achieve the objective:

1. Education phase: This includes a pre-summer media and PR effort to raise general awareness of the program; and

2. Event phase: Media and PR during events focused on immediately notifying customers an event is in effect.

The day of the event activities will include newspaper, spot radio, TV and geo-targeted online efforts. The level of media available is constrained by the fact that events are not known more than 24 hours in advance.

PG&E will begin the PTR program in 2010 and will not have the SmartMeter Program Upgrade technology and features, including interval billing, fully deployed in the PG&E service territory that year. As a result, the marketing campaign will be limited geographically in 2010 and is estimated to cost $3.4 million. Years 2011 and 2012 are estimated at the full $7.5 million annual cost for the two-phase education strategy. Years 2013-2030 have a lower annual estimated cost of $1.8 million due to the assumption of a transition to a more direct method of event notification through in-home displays and enabling DR technologies the customer will choose to install.

DRA and TURN recommend no PTR program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither PTR program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade. As discussed further in this decision, we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade. For that reason, it would also be appropriate to include the $18.3 million in PTR program costs, in rates, as requested by PG&E. However, since this decision approves a two-tier PTR incentive structure that will be detailed by PG&E in a November 2009 rate design window filing,[49] it would be more appropriate to address the costs of such a program at the same time, and we will order PG&E to do so.

While PG&E's current PTR program cost estimate of $18,342,000 is for a single tier PTR incentive structure, we will use the related PVRR of the PTR program costs, which amount to $27,592,000, for the purpose of evaluating the cost effectiveness of the Upgrade.

7.8. Project Management Costs

PG&E has forecast $15.3 million in additional project management costs associated with the Upgrade. According to PG&E, these costs are associated with additional project management efforts that will be required as the industry continues to evolve and offer new technologies. PG&E specifically cites additional project management efforts that will be required to deal with the added technological complexity of the HAN, ubiquitous load limiting switch and the advanced solid state meters and to manage additional vendors and the associated issues in contract administration and management of warranties, supply chain issues, costs and benefits realization, and performance metrics.

7.8.1. Positions of DRA and TURN

DRA excluded incremental project management costs completely from its business case, because it believes that what PG&E received in the original case was sufficient. DRA explains that while PG&E asserts that there is additional complexity associated with managing multiple technologies, in its original case, PG&E argued for the need for multiple technologies, one for gas and one for electric, and included the cost

[49] *See* Section 10.1.2.

to manage the deployment of and operation of these multiple technologies. Since the Upgrade proposes to eliminate the PLC technology, deploying only the Aclara RF technology, and PG&E anticipates introducing a second technology, Silver Springs, DRA asserts that PG&E would still be managing only two technologies as proposed in its original case.

TURN argues that PG&E has not adequately justified its request to increase its project management costs, and the Commission should reject PG&E's request. According to TURN, while PG&E states that the additional funds are supposed to pay for in-house labor costs associated with the increased costs of dealing with more vendors resulting from this "AMI Upgrade" and external professional services to help with in-house project management, risk assessment, and evaluation of PG&E's program management process, with the exception of retrofitting meters with yet unavailable HAN devices and re-deploying solid-state meters to replace stranded electromechanical meters, in general, PG&E is installing the same number of gas and electric meters that were authorized in A.06-07-027. TURN further states that PG&E may have a handful of additional vendors to administer but PG&E has not met its required burden of proof demonstrating that there is a linear function between administering a few more vendors and its proposed increase to program management costs. TURN adds that the rate at which PG&E has been spending its project management and risk allowance funds without installing many meters has led TURN to believe that PG&E's request is premised on the fact that PG&E has squandered its original budget.[50]

In response, PG&E states that it has provided substantial evidence regarding how the additional complexity of the industry and the new project technology will add to its

[50] TURN cites evidence that indicates that, while PG&E has already spent 79% of its authorized project management budget, it has only installed 4% of its forecast electric meters and 11% of total gas meter installations. Further, it has only activated 2% of its electric meters and only 1% of its gas meters.

project management costs, and intervenors cannot legitimately ignore the evidence presented by PG&E – that clearly shows a correlation between project management costs and increased numbers of vendors within an increasingly complex industry -- and instead rely on alternate theories that would correlate project management costs with the numbers of meters or networks being deployed.

7.8.2. Discussion

As discussed further in this decision,[51] we determine that PG&E's project management costs associated with the Upgrade should be considered as original AMI program costs, specifically under the risk based allowance. Therefore, for purposes of this proceeding, we need not determine an appropriate measure or theory to guide our determination of incremental project management costs, or whether PG&E's project management to date has been imprudent.

7.9. Operation and Maintenance Expense

PG&E has forecast $5.1 million in operation and maintenance (O&M) costs. These costs include O&M costs related to the load limiting switch, the HAN device and IT. The only category of these costs challenged by intervenors is that relating to expected calls to PG&E's call centers concerning the HAN device. These call center costs – forecast at $455,000 per year through 2010 – are tied to expected rates of HAN adoption.[52] That is, the higher the rate of HAN adoption, the higher the expected call center costs.

DRA's benefit calculations reflect the use of a lower HAN adoption rate than assumed by PG&E. DRA modified PG&E's annual HAN technology adoption rate by a ratio of 21 to 30, which is equivalent to a scalar adjustment of 0.7. This adjustment

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[51] *See* Section 7.12.2.

[52] In rebuttal testimony, PG&E revised its forecast of call center costs in outlying years, but the forecast through 2010 remains the same as set forth in the December 2007 testimony. *See* PG&E, Exhibit 8, p. 3-19, Table 3-1.

results in the projected annual adoption rate increases from 0.1% in year 2012 to 21% in 2024. DRA recommends reducing PG&E's call center costs by 70% to reflect the fewer calls that will be received as a result of DRA's lower HAN adoption rate.[53] DRA's adjustment results in a $319,000 reduction in O&M costs.

As discussed further on in this decision,[54] we have adopted DRA's proposed HAN adoption rates, which were derived by applying a 0.7 scalar to PG&E's proposed adoption rates. Therefore, we will apply the same 0.7 scalar to PG&E's proposed call center costs, resulting in an adopted call center estimate of $319,000, which is $136,000 less than projected by PG&E.

7.10. Technology Assessment Costs

In PG&E's original AMI decision, the Commission stated:

> While we recognize that PG&E's AMI deployment meets our functionality requirements as set forth, new technology may emerge that offers PG&E and its customers increased reliability and performance enhancements. We expect PG&E to monitor market place developments so, whenever feasible, it can upgrade its AMI system and offer its customers technology upgrades. (D.06-07-027, p. 52.)

In response to this statement, PG&E states that it has closely monitored the advancements in AMI technology advancements. In its application, PG&E proposed technology assessment and pilot costs of $15.4 million through 2012. These costs include approximately $9 million in staffing and other recurring costs and $6.4 million for a pilot test of new technologies.

Considering recent technology developments in communication networks supporting the transfer of information between a utility and its customers' premises,

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[53] DRA does not explain the apparent discrepancy of recommending adoption of 70% of PG&E's HAN adoption rates but recommending only 30% of the call center costs related to the HAN adoption rates.

[54] *See* Section 9.1.4.

PG&E indicates that it has embarked on a program to identify, evaluate, and test the latest emerging technologies that it may be able to incorporate into its SmartMeter Program Upgrade.

In its May 2008 Supplemental Testimony, PG&E included additional technology assessment costs of $22.5 million for HAN standards development. This consists of $12.5 million for demonstration facility/laboratory testing environment, $5 million for labor for HAN standards support, and $5 million for devices that would enable home computers to function as in-home display devices.

PG&E states that it will continue to work with the other utilities in California and throughout the United States to establish standards for HAN technology and applications and encourage customers to take advantage of the benefits supported by HAN-enabled functionality.

The total of PG&E's technology assessment request is $37.9 million.

7.10.1. DRA's Position

DRA states that given that PG&E's technology assessment request came in response to a Commission directive to monitor the market, DRA has proposed that this program be partially funded. DRA recommends an amount of $9 million (direct nominal dollars). DRA indicates that this figure would allow for the monitoring of emerging technologies. DRA excludes the cost of a technology laboratory, a demo facility for HAN devices, HAN standards work, development of a Zigbee device that can be plugged into a computer, and an ongoing pilot test of the Silver Springs Network.

DRA does not believe there are sufficient benefits in PG&E's business analysis to cover these costs. If the Commission disagrees, DRA would suggest moving up to a figure of $15.4 million, which is what PG&E included in its initial application and testimony in December 2007. That figure would only cover the monitoring of new technologies and the Silver Spring pilot, which is currently being carried out by PG&E anyway.

According to DRA, much of the added work that PG&E proposes is more properly done by organizations such as the Electric Power Research Institute, by national research laboratories, or by consortia jointly financed by several utilities. Furthermore, no other California utility has received an authorization to perform AMI-related research and development work at the same level as what PG&E has requested.[55] DRA states that while SCE may have received more pre-deployment money than PG&E, adding $37 million will clearly put PG&E higher than SCE.

In response, with respect to HAN standards, PG&E cites the cross-examination of DRA's witness who stated it was not unreasonable of PG&E to request the funds for one pilot during the construction of this project. He indicated there might be value to a pilot but objected to the notion of establishing the timing and cost in this proceeding. PG&E argues that DRA has not provided any evidence regarding what timing or magnitude of testing is more appropriate than that provided by PG&E, and the only record evidence on this issue supports PG&E's proposal.

With respect to pilot testing, PG&E similarly cites the cross-examination of DRA's witness who stated that he agreed that PG&E should be involved in the HAN standards development process but does not agree that PG&E's cost estimate is the right number. PG&E again argues that DRA has not provided any countervailing evidence regarding what level of commitment is more appropriate than that proposed by PG&E, and the only record evidence on this issue supports PG&E's proposal.

7.10.2. TURN's Position

Regarding PG&E's application request of $15.4 million, TURN recommends that the Commission reject the total amount.

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[55] DRA indicates that SCE received a total of $67 million in pre-deployment funding ($12 million in A.05-03-026 and $45 million in A.05-12-026). PG&E received $49 million, and when the $37 million in technology assessment costs are added to $49 million, the result is $86 million.

TURN states that when the Commission authorized PG&E's full pre-deployment funding request in A.05-03-016 it did so in part because it felt that PG&E's AMI project was farther along than the other two electric utilities and that PG&E was past the technology assessment phase and required pre-deployment funding to essentially keep its AMI deployment on track. According to TURN, requesting the additional funds to evaluate AMI technology is akin to re-asking the Commission for pre-deployment funding, and PG&E is too far along in its AMI deployment to continue wasting ratepayer money to evaluate new AMI technologies.

TURN also states that D.06-07-027 already requires PG&E to regularly assess AMI technology and to report back to the Commission on its assessments as one of the requirements for receiving authorization of its proposed $1.7 billion funding request, and the Commission has therefore already funded PG&E's technology assessment activities with that $1.7 billion authorization.

Regarding PG&E's supplemental testimony request of $22.5 million, TURN recommends that the Commission authorize $2 million to provide input to and obtain information from private sector projects that will ultimately develop HAN standards.

It is TURN's position that developing HAN standards and functionality to enhance the commercial availability of home area networks is the job of private industry not the ratepayers. Private industry will benefit from selling HAN devices to customers and, therefore, private industry should have the responsibility of developing the technology. In addition, TURN asserts that HAN devices contained within a customer's home are the property of the customer and are not necessarily wholly devoted to managing the energy usage of appliance end-uses. TURN adds that, in the context of an application to redo a multi-billion dollar project a few years after it was authorized, the Commission should not fund extraneous exercises such as this.

In response, PG&E notes the cross-examination of TURN's witness who stated (1) he could not say he had the expertise to understand exactly what was going on in the HAN industry; (2) he did not know how a standard is developed for HAN; and (3) he did not know whether or not a pilot was necessary. PG&E asserts that TURN's recommendation for this cost category is arbitrary and put forth by a witness who acknowledged that he has no specific knowledge or understanding of PG&E's technology evaluation requirements, and, therefore, TURN's recommendation should be rejected.

In response, TURN states the depth of its witness's knowledge of HAN standards development is irrelevant, given that TURN does not believe any of the specific tasks related to its proposed disallowances are necessary for upgrading PG&E's existing AMI system with new meters.

7.10.3. Discussion

PG&E's request has not been fully justified and appears to be excessive.

With respect to its application request of $9.0 million for staffing and recurring costs, PG&E indicates that it is actively evaluating broadband over power line (BPL) and medium-band over power line (MPL) network options along with Internet Protocol (IP) solutions as an approach to expand its network bandwidth and create a more open communications framework. In our previous discussion on network technologies, we gave PG&E latitude on the type of networks to be deployed, with the understanding that it would be within previously authorized budgets. It is not clear that these currently considered communication networks are deficient in particular respects. It is not clear how BPL, MPL or IP would be incorporated into the currently proposed AMI structure.

PG&E did indicate that the backhaul technology is in rapid development and there may be a time when new methods of data transport become commercially viable for deployment. However, while this may warrant continued monitoring, it does not necessarily warrant extensive evaluation processes as proposed by PG&E.

PG&E has not provided convincing evidence that its proposed technology assessment expenditures related to communication networks are necessary or reasonable.

However, since there is potential value in having PG&E monitor market place developments, we will authorize $4.0 million for that purpose.[56]

With respect to the $6.4 million pilot testing request, it appears to be related to a network technology that is currently being considered and which may be deployed as part of the Upgrade. There is value in pilot testing to ensure that the proposed network can be integrated into the AMI and will work as intended. We will authorize the requested amount.

With respect to HAN standards development costs, we are in general agreement with the positions of DRA and TURN. Laboratory testing and product demonstrations should first be the responsibility of those in private industry who will in the end profit from the various HAN related devices. Also, some of the work might be done by organizations such as the Electric Power Research Institute, by national research laboratories, or by consortia jointly financed by several utilities. We see no justification for saddling PG&E's ratepayers alone with these laboratory testing and product demonstration costs. However, PG&E has alternatively proposed that for $21 million of its proposed costs, ratepayers would provide half of the amount and PG&E would obtain the remainder from other private or public sources to defray costs that exceed the ratepayer share.[57] We see merit in PG&E's proposal as it relates to laboratory testing and product demonstrations. It is reasonable that ratepayers provide at least some of those costs related to protecting PG&E's system from such potential problems as security breaches, interference with bill reading and interruption of customers' service, which can be avoided by first testing devices in a lab that replicates PG&E's system. We will allow

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[56] For technology assessment, there is no evidence as to what costs might be reasonable for monitoring purposes as opposed to evaluation purposes. The $4.0 million amount for monitoring purposes is based on the assumption that monitoring costs and possibly some evaluation costs would be substantially less than the $9.0 million proposed by PG&E for essentially evaluation purposes.

[57] *See* PG&E Reply Comments on Proposed Decision of ALJ Fukutome, pp. 1-2.

$6 million (plus the associated risk based allowance) for this purpose with the understanding that PG&E can use those ratepayer provided funds to the extent that it matches those funds from other sources. Any unspent funds should be credited back to ratepayers.

With respect to the $5 million for labor for HAN standards support, there is value in having PG&E provide input to and obtain information from private sector projects and to interact with developers and other utilities as HAN standards are developed, and we will provide funds to do so.

With respect to the $5 million for devices that would enable home computers to function as in-home display devices, the purpose of these costs is unclear. The funding is for a device that would enable IHD functionality on a home computer but it is included under technology assessment. We are not clear as to whether the device itself is being tested or whether the customers' use of the device is being assessed. If it is the former, we would exclude the costs as being the responsibility of those in private industry who will, in the end, profit from the device. If it is the latter, we see no reason why the device should be free or discounted when, under PG&E's Upgrade proposal, the cost of the IHD is the customer's responsibility. For these reasons, we will not adopt funds for this category.

In total, the adopted technology assessment costs amount to $15.4 million.

7.11. Training Costs

PG&E has included incremental training costs of $1,697,000 for installation vendor software training, Field Automation System training, and customer call center training. No party disputes any of these costs, and they will be adopted.

7.12. Risk Based Allowance

PG&E estimates $506,920,000 in Upgrade costs and on top of this adds an additional $65,533,000 as a risk based allowance or contingency. PG&E indicates that it followed the same approach in calculating its risk based allowance for the Upgrade as it followed in its original AMI application. In D.06-07-027, for that proceeding, the Commission authorized $128.8 million for a risk based allowance on top of $1,610.6 million of estimated project costs. In the Upgrade, the risk based allowance increases costs by 12.9%, while in the original AMI application, the risk based allowance increased costs by 8.0%.[58]

7.12.1. TURN's Position

TURN recommends that the risk based allowance be limited to 7.5%, based on what was authorized in D.06-07-027.[59]

PG&E argues that its risk based allowance estimates are dependent on the category of cost and the specific risk associated with that category of cost. According to PG&E it followed the same procedure as in the original AMI application. That is, certain risk factors were assigned to specific cost categories based on PG&E's perception of what that risk factor should be. The 8% number is a result of assigning different risk factors to different cost categories and looking at the results in total. The overall risk based allowance percentage calculated for the Upgrade is higher than that of the original AMI request because the Upgrade has higher amounts of expenditures in the higher risk categories than did the original AMI request.

7.12.2. Discussion

No party appears to object to the concept of a risk based allowance or contingency. Consistent with the outcome of PG&E's original AMI decision, we will adopt the use of such a factor for the Upgrade. We understand that elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts were such things as "the types of equipment that PG&E is proposing to deploy;

[58] This overall percentage is calculated by dividing the total authorized risk based allowance by the total authorized costs less the authorized risk based allowance.

[59] TURN calculates the percentage by dividing the total authorized risk based allowance by the total authorized costs.

the maturity levels of the industries that will be providing equipment; vendor experience with similar projects; the timing and scope of the deployment efforts; the current phase of the different contract life cycles; the number and types of vendors that will be managed during the project; equipment failure rates; and other project based factors."[60] We therefore consider these elements as the types of things that should be covered by the risk based allowance for both the original AMI project and the Upgrade.

Consistent with the manner in which the risk based allowance adopted in D.06-07-027 was calculated, we will adopt a risk based allowance for the Upgrade based on the risk profiles of the specific categories of Upgrade costs. That PG&E's estimated overall Upgrade risk based allowance factor of 12.9% is higher than the 8.0% allowance for the original AMI project is a result of PG&E's analysis of risk for specific categories of Upgrade related costs as opposed to its analysis of risk for specific categories of costs for original AMI project. We agree with PG&E's position that the analysis of risk for the Upgrade should consider the risk profiles specific to the Upgrade, rather than that of the original AMI project.

Because of the manner in which TURN's recommended risk based allowance factor is derived, there are no specific evaluations of, or agreements or disagreements with, the specific risk factors that PG&E has assigned to the various cost categories. However, it is not surprising that overall risk related to newer technologies included in the Upgrade, in particular the currently evolving HAN technology, and the information technology system integration might have higher risk factors than that for the more traditional technologies that were included in the original AMI project. A review of PG&E's proposed risk factors does not cause any specific concerns with the magnitude of the factors or with the cost categories to which they are applied. We will therefore

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[60] *See* Exhibit 8, p. 10-10.

adopt PG&E's proposed risk base allowance methodology along with the specific factors themselves and the categories of cost to which they are applied.

In adopting PG&E's broad application of the risk based allowance methodology to its cost estimates, for both the original AMI project and the Upgrade, we feel it is vital to fully consider the implications of the risk based allowance concept. Specifically, we must consider if, and to what extent, it can be assumed that the risk based allowances for the original AMI project should cover specific requested Upgrade costs. Also, going forward, we must be vigilant in identifying future costs related to the Upgrade that should be covered by the risk based allowance that we are adopting today, rather than covered by additional rates adopted in another proceeding where such costs might be raised, such as in a future general rate case (GRC).

Regarding future costs that may be related to the original AMI project or the Upgrade and which are raised in separate proceedings for the purpose of additional rate recovery, they are only speculative at this time. We can only note that, in order to get such additional rate recovery, PG&E has the burden to show that such costs are neither covered by the specific costs adopted in either proceeding nor by the risk based allowances adopted in either proceeding.

Regarding requested Upgrade costs that should be covered by the risk based allowance adopted in D.06-07-027 for the original AMI project, two requested Upgrade costs are of concern. They are the incremental project management costs and certain of the costs related to the Kern County electromechanical meter retrofit.

For project management, PG&E requests additional cost recovery for activities related to the newer technologies and an increased number of AMI vendors mostly caused by the added Upgrade functionalities. However, PG&E itself, as described above, includes "the types of equipment that PG&E is proposing to deploy … and the number and types of vendors that will be managed during the project" as elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade, and we see no reason why it should be any different for the original AMI. It follows that these activities are of the type that should be covered by contingencies such as the risk based allowance. It is reasonable that the additional project management costs requested by PG&E as part of the Upgrade should instead be covered by the risk based allowance adopted in D.06-07-027.[61] The requested amount of $15.318 million ($17.914 million PVRR) will be excluded from the adopted Upgrade costs.

For the electromechanical upgrade, it is reasonable to include the incremental costs of the advanced solid state meter, the integrated load limiting connect/disconnect switch, the HAN gateway device and the installation cost as part of the Upgrade costs. These are the specific costs necessary to provide the functionalities of the Upgrade project and are reasonable. However, the electromechanical upgrade also includes the costs needed to install the approximate 230,000 electromechanical meters that are being replaced by the upgraded devices. The question to consider is whether the stranded costs related to the premature retirement of the electromechanical meters should be absorbed through rates established for the original AMI or through rates established for the Upgrade. The decisions to deploy the electromechanical meters were made by PG&E in conjunction with the original AMI authorization. It is appropriate that the consequences of those decisions should be reflected as part of that same authorization.

Also, as indicated above, PG&E has identified changed timing and scope as elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade, and we see no reason why it should be any different for the original AMI. Changed scope (i.e., advanced meters with higher functionality) is the driving factor that resulted in the electromechanical meters and associated equipment becoming obsolete. It follows that the costs imposed by the

[61] This adjustment does not apply to information technology project management, which has been estimated by PG&E to be $2.8 million, plus the associated risk based allowance. That amount is included in this decision as an authorized cost.

premature retirement of the electromechanical meters are of the type that should be absorbed through the risk based allowance. Those costs were imposed as part of the original AMI project and it is reasonable to assume the related stranded costs should be covered by the risk based allowance authorized by D.06-07-027 for the original AMI project. We will therefore exclude $18.5 million ($20.0 million PVRR) related to the Kern County electromechanical meter retrofit from the adopted Upgrade costs.

8. Operational Benefits

Operational benefits include (1) the elimination of labor costs currently required for manually turning on or off a customer's electrical usage at the premises; (2) bad debt reduction resulting from earlier collection of outstanding balances and earlier shut-off; and (3) cash flow savings from these earlier collections and shut-off. Also, PG&E has identified a tax benefit from meter retirement that is included under this category of benefits.

8.1. Field Technician Labor Savings

PG&E proposes to install integrated load limiting connect/disconnect switches in the solid state meters for all single phase residential meters with a maximum of 200 amperes (amp). While deployment of these switches could begin in the latter half of 2008, for purposes of its benefits analysis, PG&E expects that activation of these switches will occur once enabled through PG&E systems in July 2009.

Electric field technicians typically perform four types of connect/disconnect services at premises with a single-phase residential meter with a maximum of 200 amps: customer move-out, customer move-in, Shut-off for Non-Payment (SONP), and reinstatement of SONP (RSONP). PG&E estimates that it will realize a total of approximately $6.9 million in incremental operational benefits during 2009 and 2010 that relate to the savings from the elimination of labor costs currently required for manually turning on or off a customer's electrical usage at the premises. That is, PG&E offsets the overall O&M labor savings from the integrated load limiting connect/disconnect switches with the O&M labor savings for the 600,000 disconnect collars it included in the original AMI Application.

No party has challenged either PG&E's inclusion of field technician labor savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.2. Reduced Bad Debt Savings and Cash Flow

According to PG&E, the integrated load limiting connect/disconnect switches will also help PG&E reduce bad debt and improve the timing of cash flow. Each month, approximately 41,000 PG&E residential customers are eligible to be SONP. Due to manpower constraints, only an estimated 13,000 of these 41,000 SONPs (i.e., 32%) are physically turned off each month by sending a field service representative to the premises. The remaining 28,000 (i.e., 68%) are not shut-off and continue cycling for another month. Further, there are two categories of SONPs: (1) those that ultimately remit the balance due; and (2) those that do not and for whom their owed balance must be written-off as bad debt. Based on historical data, PG&E collects approximately 92.2% of SONP balances; the remaining 7.8% are written off.

8.2.1. Reduced Bad Debt Savings

For the SONP balances that are ultimately written off (i.e., 7.8%), the benefit of performing the turn-off remotely is that the turn-off is done more quickly, which results in a lower balance to be written-off as bad debt. The incremental benefits of the load limiting connect/disconnect switch vary, however, depending on whether that SONP would have been processed during a given month. PG&E forecasts that it will realize a total of $1.7 million in bad debt savings in 2009 and 2010.

No party has challenged PG&E's inclusion of bad debt savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.2.2. Improved Timing of Cash Flow Savings

For the SONP balances that are ultimately collected (i.e., 92.2%), the benefit of performing the turn-off activity remotely is that the turn-off is done more quickly, which results in making a collection sooner. That is, the benefit is the time value of money associated with the collections. PG&E forecasts that it will realize a total of $0.7 million in the improved timing of cash flow in 2009 and 2010.

No party has challenged PG&E's inclusion of these cash flow savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.3. Tax Benefit from Meter Retirement

Since PG&E proposes to replace all existing electromechanical meters with solid state meters, PG&E will need to retire the existing electromechanical meters. PG&E explains that for tax purposes, there will be a loss on the retirement that will be recognized to the extent that the remaining (i.e., undepreciated) tax basis of the assets exceeds the net salvage value, after subtracting the cost of removal. Since for purposes of this calculation, PG&E assumes that the salvage value and removal costs are approximately equal, the loss on retirement would be equal to the remaining (i.e., undepreciated) tax basis of the asset. The associated benefit is the time-value of money associated with receiving a current deduction for the loss on retirement, instead of waiting for the depreciation deduction over time, based on the tax-life of the asset. PG&E compared the present value of the tax benefit associated with the expected depreciation stream of the assets (assuming they remained in service) with the present value of the tax benefit associated with the expected loss on retirement of assets, to derive a net benefit of approximately $11.8 million.

8.3.1. TURN's Position

According to TURN, tax retirement benefits are actually an accounting treatment and not an increase in efficiency or a savings in operational expenses. Essentially, the tax benefits only mitigate the stranded costs that will arise from PG&E retiring all of its existing electromechanical meters. TURN does not consider this to be a "benefit" of the project.

In response, PG&E states that, regardless of the categorization of these benefits, there is no debate regarding the savings to ratepayers that result from these tax benefits. These savings rebound to the benefit of ratepayers through lower requested revenue requirements both in this case and for future proceedings where the tax savings are realized. According to PG&E, whether these tax benefits are categorized as an operational benefit that reduces costs to ratepayers or as an accounting treatment that reduces project costs, the end-result is the same. PG&E argues that TURN's distinction is one of semantics and should be disregarded.

8.3.2. Discussion

No party has challenged PG&E's calculation of this tax retirement benefit. Whether it is identified as a benefit or a reduction to costs, the net effect with respect to a benefit/cost analysis will be the same, and, in either case, that net effect should considered in evaluating the cost effectiveness of the Upgrade. For the purposes of this proceeding, it is reasonable to include the undisputed amount of this tax benefit as a "benefit," and we will do so.

8.4. Remote Programmability

In rebuttal testimony, PG&E raised the issue of a remote programmability benefit. PG&E states that the upgraded meter and communication device will have enhanced processing, storage, and remote programmability benefits that will allow the meters to be upgraded remotely via a network download. According to PG&E, this type of capability will have tangible operational benefits and presents the following example:[62]

> PG&E states that in the next 20 years we can expect computing power needs at the endpoints to increase at a high rate, and that one of the needs

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[62] *See* PG&E, Exhibit 8, pp. 3-17 - 3-18.

> and drivers for this computing power is the issue of data, device and operational security. According to PGE, the upgraded meter and communication devices have the ability to be remotely programmed, much like today's modern computers, and the capability to transmit or implement security or functionality patches will be critical to ensuring a reliable and secure network over time.
>
> PG&E believes the benefits associated with the ability to implement this one capability alone through the remote downloading of the necessary software updates and security upgrades to meter endpoint platforms capable of taking advantage of those downloads are significant. According to PG&E, the benefit arises because the ability to remotely reprogram an advanced meter allows PG&E to avoid the need for a field visit to each meter needing reprogramming.
>
> Based on a cost of about $20 per meter, PG&E estimates the cost of reprogramming all of PG&E's 5.4 million electric meters would be $108 million (nominal). PG&E goes on to state there are several reasons that system-wide software upgrades or patches are likely to be required over the 20-year system life. First, there is the issue of security discussed above. Second, there are likely to be several software updates over the course of 20 years. Seven-year replacement intervals are to be expected for many types of software. Furthermore, in between replacements, software and security patches are frequent.
>
> For these reasons PG&E determines it is reasonable to assume that it would have to perform system-wide software patches or replacements at least every three years. Assuming modest labor escalation and system growth, PG&E estimates the incremental benefit of installing endpoints and systems robust enough to handle these expected upgrades remotely to be at least additional $520 million (PVRR) over the 20-year life.

In its opening brief, PG&E states that the significance of this very important addition to the project should not be overlooked.

8.4.1. DRA's Position

DRA indicates that in evaluating this example, one must be clear about what "status quo" reference point is being used to calculate the benefit. According to DRA, the calculation of any benefit is always in reference to some other state. If benefits are to be calculated on an incremental basis relative to the DCSI-based AMI system examined in A.05-06-028, then the reference point is that system. If benefits are calculated on a total basis, including those achievable by the AMI system examined in A.05-06-028, then the reference point is the pre-AMI stock of electromechanical meters with no communications capability.

DRA states that it should be obvious that the pre-AMI meters had no security problems other than a minor amount of energy theft. The meters were mechanical and did not include any components that could be reprogrammed. Hence, no truck rolls were required to change software for the entire stock of meters. DRA also states that the situation is similar with the DSCI system examined in A.05-06-028, since the DCSI system is relatively impermeable to security threats.[63] DRA notes that had there been a security problem, the business case evaluated in A.05-06-028 would have had to include an additional $520 million to cover the cost of such truck rolls, adding there was no money included for this purpose.

DRA asserts that PG&E's argument collapses into nothing more than a solution to a problem created by the enhanced functionality added by the AMI upgrade. It was not a problem with the system examined in A.05-06-028, or with the pre-AMI meter stock. Thus this benefit does not belong in the benefits stream.

8.4.2. TURN's Position

TURN also asserts that the Commission should reject the use of this benefit for cost effectiveness purposes. TURN first states that the inclusion of this operational benefit in rebuttal testimony is procedurally incorrect as PG&E raised the issue for the first time in rebuttal and the issue was not responsive to any party's testimony. TURN then states that the benefits cannot be justified as an incremental benefit of the SmartMeter Upgrade, since the purported costs could not and were not included in the

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[63] *See* PG&E, Vahlstrom, 1 RT 133.

original AMI application. According to TURN, in order to claim a $520 million benefit of avoiding reprogramming costs, PG&E would have needed to be burdened with those costs in the first place, either before the AMI program ever existed or, at least, as part of the original AMI filing. However, the old electromechanical (non-AMI) meters did not require reprogramming nor did the DCSI electromechanical AMI meters require such servicing.

8.4.3. Discussion

We agree with DRA and TURN on this issue and will not reflect remote programmability as a benefit in the Upgrade cost effectiveness analysis. As both parties indicate, the need for reprogramming the advanced meters is caused by the added functionality of the programmable meter itself. The $520 million in potential costs are just that. They are potential costs that never existed. They are avoided because the meter that necessitates the costs can accomplish the task remotely. To assign this purported benefit as an incremental benefit in the cost effectiveness analysis of the Upgrade is illogical and inappropriate.

9. Conservation Benefits

PG&E asserts that the SmartMeter Upgrade Program with the HAN gateway device will enable PG&E to offer a set of information tools to residential customers that will allow for increased energy conservation. That is, the feedback of information on energy usage will increase energy awareness, resulting in a modification of energy usage behavior. PG&E cites a study that reviewed over 100 DR programs and showed residential customers who were provided with daily feedback on their electric usage via the Internet or in-home displays reduced their energy consumption by an average of 11%.[64] Another study that focused on general energy conservation, instead of DR

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[64] King and Delurey, Efficiency and Demand Response: Twins, Siblings, or Cousins? Public Utilities Fortnightly, March 2005, p. 57.

reductions, found feedback on consumption resulting in energy savings ranging from 0% to 20%.[65] The author concluded that "feedback is an essential element in effective learning" and that feedback will have a significant role to play in raising energy awareness and in bringing about reduced consumption on the order of 10%.

PG&E's HAN gateway device will allow a customer purchased device with compatible communications technology to receive near real time information on the customer's energy use. According to PG&E, in most cases today, even with the next day web presentment of interval data (hourly for electric and daily for gas) included in PG&E's original AMI business case, customers evaluating their energy use or efficiency options will use survey or audit tools that must rely on average appliance consumption assumptions. PG&E asserts that (1) getting the consumption rate shortly after turning on appliances like the dishwasher or laundry equipment would have a more immediate impact; (2) customer interest in more detailed information can be inferred by the fact that plug in devices are appearing in retail stores to measure plug load; and (3) near real-time feedback in combination with interval data on the web will provide a powerful diagnostic tool for customers interesting in managing their energy use for financial, environmental or societal reasons.

PG&E estimated conservation benefits starting in 2012 using the following assumptions:

ffi A technology adoption curve adapted from historic cell phone annual adoption rates;

ffi Adoption rates begin at 2% in 2012, top out at 30% in 2024, and remain flat until 2030;

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[65] Darby, Sarah, "Making it obvious: Designing feedback into energy consumption." Proceedings of the 2nd International Conference on Energy Efficiency in Household Appliances and Lighting. Italian Association of Energy Economists/EC-SAVE programme, 2004 and The Effectiveness of Feedback on Energy Consumption, Environmental Change Institute, April 2006.

ffi An average of 6.5% energy conservation for both electricity and natural gas annually for a customer with an in-home display device;

ffi Average usage per customer is based on PG&E's share of the CEC's 2008-2018 demand forecast;

ffi Energy forecasts for 2019 through 2030 are extrapolated from the average annual growth rate in the 2008-2018 forecast; and

ffi PG&E's share of the CEC demand forecast is estimated based on PG&E's 2006 FERC Forms 1 (electric) and 2 (natural gas) sales as a percent of the CEC's area recorded 2006 sales.

9.1. Electric Conservation Benefits

For the time period 2012 – 2030, PG&E estimates an electric conservation level of 10,194 gigawatt-hours (GWh) resulting in a PVRR benefit of $311,881,000, as quantified in the application. That amount would be $384,067,000 if updated for more current energy costs recently incorporated into the E3 model for the 2009-2011 energy efficiency program cycle. PG&E recommends that the Commission should consider the updated amount.

9.1.1. DRA's Position

DRA's estimate of electric conservation benefits is $209 million. DRA's analysis of the upgrade's potential electric energy conservation benefits hinges on three issues: (i) a comparison of the daily information feedback that customers can achieve through PG&E's approved AMI system, as opposed to the real-time feedback that the upgrade potentially provides; (ii) a different annual adoption rate of information display technology; and (iii) a double counting of energy efficiency benefits issue between this application and the energy efficiency program proceeding.

DRA accepts that direct information feedback has potential to deliver conservation benefits, however DRA distinguishes between the effects of real time versus day-late information. DRA argues that day-late information feedback conveyed via the personal computer can be achieved with the already approved AMI system. Furthermore, it is DRA's position that day-late presentation of usage information affects space conditioning usage, as it provides customers with insight into energy used for heating and cooling. DRA cites the work of Lou McClelland and Stuart Cook of the Institute of Behavioral Science at the University of Colorado that concluded, "…conservation actions taken by households with [display monitors] primarily affected energy uses other than heating and cooling."[66]

Using the California Energy Commission 2006 Update to the Residential Appliance Saturation Survey results for the PG&E service territory, DRA calculates that approximately 9.5% of the residential load is attributable to space heating and cooling, with the other 90.5% of residential energy sales attributable to base energy usage. DRA applied the 90.5% scalar adjustment to PG&E's annual residential sales forecast, which discounted the portion of residential sales forecast due to space heating and cooling load, leaving only the base energy load in the benefit calculations. This results in a PVRR reduction of $30 million to PG&E's application benefit estimate.

DRA also disagrees with PG&E's use of the cell phone adoption rate to determine such a rate for in-home information display devices, and instead used an adoption rate of compact fluorescent lamps (CFLs), which it considers to be a more analogous historic adoption rate of residential energy efficient technology. DRA made use of a report that examined the effect of customer preference on cost potentials of residential lighting.[67] In the report it was calculated that, by 2005, a cumulative 25% of all residential light fixtures are assumed to be using CFLs. DRA then modified the HAN technology adoption rate by a ratio of 21 to 30, or a scalar factor of 0.7, resulting in adoption rates

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[66] McClelland and Cook, 1979, "Energy Conservation Effects of Continuous In-home Feedback in All-electric Homes," Journal of Environmental Systems, 9 (2), pp. 169-173.

from 1% in 2012 to 21% in 2024 and a further PVRR reduction of $84 million to PG&E's application benefit estimate.

It is also DRA's position that, if customers do adopt HAN-enabled information feedback technology and conserve electric energy, the energy savings associated with the SmartMeter Upgrade should not be used to justify both the SmartMeter Upgrade cost and the shareholder incentive that PG&E would inevitably earn as the result of the Commission's D.07-09-043 on the shareholder risk/reward incentive mechanism for energy efficiency programs. DRA explains that the electric energy conservation benefits justify dollar-to-dollar the Upgrade project cost and the associated return on equity, and, if not properly accounted, PG&E shareholders would earn another 12% on the same energy saving benefits. Therefore, DRA proposes that 12% of the energy conservation benefits be deducted, to reflect the shareholder incentives PG&E could have earned if the energy savings attributable to the SmartMeter Upgrade were not separately identified from those due to energy efficiency programs. This results in a further PVRR reduction of $24 million to PG&E's application benefit estimate.

Lastly, DRA agrees with PG&E's position that updating the estimate of electric conservation benefits for more current energy costs recently incorporated into the E3 model for the 2009-2011 energy efficiency program cycle is appropriate. This results in a PVRR increase of $35 million to DRA's estimate of electric conservation benefits.

In response to DRA, PG&E argues that DRA's 9.5% adjustment related to space heating and cooling should be rejected. Regarding the 1979 study by McClelland and Cook used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage, PG&E states that a careful review reveals that: (1) it contains no actual data on day-late feedback and space heating and

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[67] "Market Failures, Consumer Preferences, and Transaction Costs in Energy Efficiency Purchase Decisions" by Jayant Sathaye and Scott Murtishaw for the Lawrence Berkeley National Laboratory, 2005.

conditioning; (2) its statements about a reduced effect of real-time feedback on those end-uses are inferences; and (3) its interpretation of customer usage differences associated with real-time feedback supports a positive relationship in the study's summer months. PG&E also points out that there is nothing to indicate that day-later feedback was involved or studied, and the only information feedback described in the article was real-time. According to PG&E, lacking actual data, the authors inferred that the monthly differences between the test and control groups' energy consumption "suggest" that the monitors had a greater effect on uses other than heating and cooling. That interpretation, however, is attenuated in PG&E's opinion, given the study's lack of any identified day-late data collection or day-late feedback.

PG&E also asserts that most customers' access to their usage data via the web will be too infrequent to produce conservation benefits DRA claims for day-after information. The evidence indicates that 50% of customers indicate an interest in checking their usage via the internet once a month and, in the Statewide Pricing Pilot, 77% of customers visited the website at some time during the program. According to PG&E, that frequency is no better than the monthly bill that customers receive, and even if day-late feedback were sufficient to produce energy conservation benefits for space heating and conditioning, the majority of residential customers essentially will not use the AMI system's web-presentment next-day functionality for that purpose. According to PG&E, for many of these customers, the Upgrade HAN and IHD will be a better way of providing usage feedback that the customer will frequently see.

PG&E also disagrees with DRA's use of the percentage of residential light fixtures with CFLs to determine an IHD adoption level of 21%. PG&E does not object to the idea of using CFL data to develop IHD adoption levels, but maintains that CFL lamp penetration for fixtures is not an appropriate metric. PG&E argues that since a single household will have multiple light fixtures, it is not appropriate to assume that the percentage of light fixtures is an appropriate proxy for the number of households adopting IHDs, especially in light of the fact that most research to date was done with a single in-home display device per household. PG&E believes that the CFL household adoption is more analogous to the household adoption of IHDs than DRA's use of CFL lamps in fixtures.

While the report used by DRA provided the basis for its estimated assumption about the percentage of all fixtures assumed to be using CFLs, PG&E refers to a second report cited by DRA entitled "Compact Fluorescent Lighting in America: Lessons Learned on the Way to Market" that reports on an on-site survey of California CFL usage.[68] This report indicates that 57% of homes in the 2004-2005 California Case Study had one or more CFLs installed. PG&E also notes that the 2005 update to the California Statewide Residential Lighting and Appliance Saturation Study found 57% of all homes had one or more CFLs installed, and the 2004 Residential Appliance Saturation Survey for PG&E found 51% of households with at least one CFL. Based on these studies, which show similar household penetrations for CFLs at over 50%, PG&E asserts that its 30% IHD adoption level is conservative and should not be adjusted downward.

PG&E also opposes DRA's recommendation to reduce electric conservation benefits by 12% due to the shareholder risk/reward incentive mechanism for energy efficiency programs, for two reasons.

First, PG&E indicates that even under the current mechanism, the utilities only claim energy efficiency for their energy efficiency program applications under the incentive mechanism; they do not make claims for energy conservation savings. With respect to the Upgrade conservation benefits, PG&E states there is insufficient information to differentiate between energy efficiency program benefits versus other energy conservation. Hence, DRA's adjustment would be too large, even based on their theory.

[68] Portions of the report were entered into evidence as Exhibit 22.

Second, the scope and structure of the incentive mechanism for 2012 and beyond is unknown at present. In D.07-09-043, the Commission directed the Energy Division to prepare a report by February 2011 so the Commission can consider possible modifications to the incentive mechanism in time for the 2012-2014 program cycle. PG&E indicates there will be many factors to consider, such as the Assembly Bill (AB) 32 framework as well as how the Commission defines the accounting rules for that period. PG&E agrees that there should be no double payment, and that the effect of the SmartMeter upgrade should be factored into the Commission's proceeding when it finalizes the energy efficiency goals for the 2012 and beyond period for the utilities. However, PG&E asserts that the coordination of Upgrade conservation benefits with the energy efficiency incentive mechanism framework for 2012 and beyond should occur when the Commission establishes that framework.

9.1.2. TURN's Position

TURN notes that even though the display is an essential component of the notification protocol for the PTR rates and PG&E also relies upon the device to achieve sizeable conservation benefits, initially PG&E did not include any cost for this device in the application. Rather PG&E assumed that the homeowner will purchase it voluntarily. PG&E presented no evidence as to the cost of this device, and also lacks evidence that the customer will save enough energy to make purchase of the device cost effective. TURN also notes that, while in its supplemental testimony PG&E included $5 million to "promote the specification and adoption of consumer in-home devices" using a proxy price of $20 for an in-home device, no evidence has been provided that $20 is sufficient for an in-home display device of the type PG&E envisions.

According to TURN, evidence shows that devices that provide the benefits PG&E claims will result in conservation cost far more than PG&E indicates. For example, the Kill a Watt device for $25 will only display one device at a time, provides a readout only at the plug, could be hard to use behind a refrigerator, washer, dryer or any other bulky appliance, and is not designed for 220-volt appliances. A more powerful device, such as the Blue Line Powercost to monitor full house usage, is considerably more expensive at $140. According to TURN, only a device such as this is capable of monitoring more than one or a few devices plugged into the same power strip, and only a device of this cost level can monitor heating and cooling systems.

The lack of reasonably priced devices to achieve the benefits PG&E claims causes TURN to question the reasonableness of PG&E's energy conservation benefit.

In response, PG&E states that its data request response[69] on IHD costs ranging from $25 to $235 confirms that the customer would purchase the display himself/herself. PG&E further states that it expects that future costs of simple IHDs will drive even lower and that IHDs costing less than $5 will become available. PG&E elaborates that some customers may want a very simple device that only provides one or two pieces of information, while other customers may want to have more features—for which they will be willing to pay. Also, the existing devices do not use HAN and must have a means of capturing interval load from the meter and displaying the information, such as with a "clamp on CT." In the future, HAN will perform the job of capturing the interval data, relieving the IHD of that function. With HAN, the IHD will only need to perform the receiving and display function, which will contribute to lower IHD costs. PG&E concludes that, as the technology and market develops, the costs of IHDs may also be expected to decline, just as the cost of solid state meters has come down significantly between its original AMI case and this case.

9.1.3. CCSF's Position

CCSF agrees with DRA's position that instead of relying on adoption rates for cellular telephones to determine HAN adoption rates, PG&E should have relied on adoption rates for CFLs.

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[69] See Exhibit 203.

Also, CCSF claims there is no evidence to support PG&E's assumption that its customers will use real time pricing information obtained from IHDs to change their electricity usage patterns. CCSF apparently argues that if customers are not using historical usage information available through web-presentment in the AMI project, there is no reason to think that they will use real-time information from IHDs.

In response, PG&E states there is solid evidence that IHDs do elicit significant conservation by showing customers how much energy they are using. According to PG&E:[70]

> This is because displaying current energy usage in the home will reduce the effort required by customers to monitor their energy usage and correlate energy use changes associated with behavioral changes. Numerous research studies confirm that 'direct feedback,' such as that provided on demand by the customer through the HAN gateway device and a receiving in-home display device, provides more energy conservation than 'indirect feedback' such as monthly bills plus historical feedback. [Footnote: Darby, Sarah, 2004. 'Making it obvious: Designing feedback into energy consumption." Proceedings of the 2nd International Conference on Energy Efficiency in Household Appliances and Lighting. Italian Association of Energy Economists/EC-SAVE programme.]

Also, while PG&E and DRA disagree on the IHD impact on space heating and conditioning, PG&E notes that DRA acknowledges that, for other end uses, IHDs do promote energy conservation with respect to over 90% of electric use.

9.1.4. Discussion

To begin, we do not agree with DRA' adjustments for space heating and cooling or for double counting related to the shareholder risk/reward incentive mechanism for energy efficiency programs. Regarding the space heating and cooling adjustment, even if heating and cooling conservation can be accomplished through day-ahead notification, we have previously noted that we will use PG&E's definition of "incremental" for this

[70] Exhibit 3, p. 5-8.

proceeding. Therefore, since conservation benefits were not quantified in the original AMI proceeding, the conservation benefits we are considering for the Upgrade can result from either the results of the functionality of the original AMI request (day ahead information) or of the Upgrade and the HAN (near real time information). Also, in general, we agree with PG&E's response regarding the 1979 study by McClelland and Cook used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage. In light of PG&E's criticisms, that study does not provide persuasive evidence to support DRA's conclusions on this issue.

Regarding potential double counting related to the shareholder risk/reward incentive mechanism for energy efficiency programs, we note PG&E's assertion that the incentive mechanism relates to energy efficiency and not conservation and that its conservation benefits for the Upgrade include both. Since neither PG&E nor DRA separated energy efficiency from the conservation benefit estimate, we cannot properly apply a factor to prevent potential double counting of energy efficiency. Therefore we will not reduce PG&E's estimate of electric conservation benefits by 12% as recommended by DRA. Instead, when the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, PG&E should ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the Upgrade.

Regarding PG&E's estimate of 30% IHD penetration as opposed to DRA's estimate of 21%, we note that the estimates are based on new technology acceptance curves for different products (cell phones and CFLs). At this point, we have no way of knowing for sure which estimate is better. Both are educated guesses that are not substantially different. However, we will adopt DRA's lower value of 21%. We prefer to be conservative with respect to estimating this benefit partly because of the speculative nature of the forecasts and partly due to TURN's legitimate concerns regarding the cost of the IHD devices. Whether costs will be a significant impediment to customer acceptance is unknown. As does PG&E, we expect the prices of such devices to decline as the technology and market develops, but the economics have not been fully analyzed by any of the parties.[71] There is uncertainty. Therefore, we feel that a reduction to PG&E's estimate of electric conservation benefits is reasonable.

With respect to CCSF's criticism regarding PG&E's assumption that customers will use information obtained from IHDs to change their electricity usage patterns, we feel there is sufficient evidence, as noted by PG&E, to determine that such devices do have that effect. CCSF has not cited any studies or produced any persuasive evidence to rebut those conclusions. Therefore, we will not adjust the estimated electric conservation benefit for that reason.

Finally, both PG&E and DRA recommend that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade, and we agree that it is reasonable to do so.

Based on the above discussion, we will adopt an electric conservation benefit amounting to $268,847,000 (PVRR).

9.2. Gas Conservation Benefits

For the time period 2012–2030, PG&E estimates a gas conservation level of 10,194 billion British thermal units (BBTU) resulting in a PVRR benefit of $167,190,000.

9.2.1. DRA's Position

DRA questions the effect of the electric metering system upgrade on gas conservation, quoting PG&E's statement that the proposed SmartMeter Program Upgrade does not affect PG&E's gas meter infrastructure.[72] DRA also states that PG&E justified

[71] TURN has not proposed a methodology for quantifying this effect.

[72] PG&E, Exhibit 2, p. 2-5.

its gas system technology and network provider in its original AMI case by stating that its technology provided functionalities that:[73]

> Allow one-way or two way radio communication capability directly to each premise with PG&E gas service; use highly reliable and powerful licensed radio frequency communication channels owned by PG&E; provide 100% coverage for all gas customers in one system; has proven module battery backed by the best proposed warranty; provide daily gas usage with the potential for hourly data for selected customers; provide customer level tamper detection information; and enable messaging for smart thermostats, in-home displays, and home automation.

It is DRA's position that, since PG&E's gas AMI system was approved in D.06-07-027 and the SmartMeter Upgrade does not pertain to the gas AMI system, PG&E's $167 million claimed benefit of gas conservation is not contingent upon the approval of the SmartMeter Upgrade, and consequently the overall project benefit should be reduced by $167 million.

In response TURN argues that DRA errs in its description of the gas AMI system, and also misses the importance of HAN-enabled in-home information on energy conservation in general.

First, PG&E states that it clarified in rebuttal testimony that its request for the gas AMI system did not include equipment and technology required for in-home gas information display capabilities.

Second, PG&E states that the importance of HAN-enabled IHD is the increased awareness of energy usage occurring at the time in the customer's home. That awareness can extend beyond electrical consumption displayed on the IHD. According to PG&E, experience with residential customer surveys indicates many customers do not clearly differentiate electric and gas consumption by their appliances. PG&E points out that for these customers, the increased awareness of energy use occurring right then-and-there in

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[73] A.05-06-028, Exhibit 8-1, p. 1-7.

their homes may encourage immediately cutting back on energy consumption, including gas use. For those customers who are aware of gas versus electric consumption, PG&E states that near-real time HAN enabled IHD information on electric use from motors or fans associated with gas appliances also could support reducing gas consumption by those appliances. Consequently, PG&E asserts that assuming no connection between HAN IHD near-real time information display and gas conservation as DRA has done, takes an overly restricted view of the effects of immediate energy usage feedback on residential customer behavior.

9.2.2. Discussion

We are not convinced that any gas conservation benefits should be attributed to PG&E's original AMI project or to the Upgrade. The IHD shows electricity usage, not gas usage. By looking at the IHD, there is no way to tell if gas usage is high or low or possibly whether any gas is being used at all. If a customer reduces gas usage (e.g., space heating, water heating, drying clothes, or cooking), it is probably for economic reasons. That economic incentive is likely a result of a gas bill or an examination of gas rates rather than a customer looking at an IHD and noting electricity usage patterns.

With respect to customers that supposedly do not clearly differentiate electric and gas consumption by their appliances, there is no record evidence indicating what proportion of the customer base that might be. Furthermore, there is no record evidence indicating whether such customers would be the type that would even purchase an IHD. We cannot accept PG&E's reasoning on this issue as sufficient support for its gas conservation benefit estimate.

PG&E hypothesizes that near-real time HAN enabled IHD information on electric use from motors or fans associated with gas appliances could support reducing gas consumption by those appliances. We only note that a fan being on is one thing, knowing what the gas usage is and whether it is high or low is another thing. Also, it is fairly easy to know whether one's gas space heater is on. If heat is coming out of the vent, gas is probably being used at that time. The same can be said regarding a gas stove.

If one is cooking, gas is being used. Neither PG&E's original AMI project nor the Upgrade is necessary to make those determinations. While the IHD can display near real time electricity usage and customers can view that information to determine whether they should cut back or not, the IHD does not display such information for gas. We do not feel that customers' decisions as to whether they should limit or curtail gas usage are significantly enhanced by the presence of IHDs that only display electricity usage patterns.

Therefore, we will assign zero gas conservation benefits in our cost effectiveness analysis of the Upgrade.

10. Demand Response Programs

10.1. PG&E's PTR Program Proposal

PG&E's proposed PTR program would offer new monetary incentives to encourage residential customers to reduce their peak period usage on up to 15 event days per summer. PG&E states that the PTR program is being proposed in part to allow for a consistent residential DR program offering across all three major California investor-owned utilities, and in part to achieve additional DR participation from residential customers who might not otherwise be reached by residential CPP rates alone. By PG&E's proposal, the PTR program will be available to customers starting in summer 2010.

The PTR program would be established as an overlay to the customer's otherwise applicable residential tariff (OAT) by applying bill credits of $0.60 for each kilowatt-hour (kWh) reduced during an event day. The energy reduction from each event will be measured against a customer-specific reference level (CRL) that is calculated for each customer. The proposed peak period times are from 2:00 p.m. to 7:00 p.m. According to PG&E, this approach is similar to those currently under consideration for both SDG&E and SCE, but has been adapted to comport with PG&E's adopted residential CPP program -- the residential CPP and PTR programs offered to PG&E's residential customers would match both in terms of operating hours (2:00 p.m. to 7:00 p.m.) and pricing level ($0.60 per kWh). PG&E also anticipates initiating CPP calls and PTR events on the same summer peak days.

According to PG&E, due to AB 1X,[74] residential customers currently cannot be placed on a mandatory rate schedule or overlay that can result in higher bills for Tier 1 and Tier 2 usage. PG&E argues that the limitations created by AB 1X mean that dynamic pricing programs that could potentially increase customer bills (e.g., CPP) may only be offered to residential customers on a voluntary basis.[75]

PG&E states that until the AB 1X restriction is lifted, PTR will be a preferred choice for maximizing DR from residential customers.[76] Because there is no downside risk, PG&E recommends that all residential customers be automatically enrolled in PTR once they are fully connected to the network, unless they are enrolled in CPP. PG&E reasons that automatic enrollment in PTR overcomes the hurdle of inertia (i.e., maintaining the status quo) that comes with recruiting customers onto a new program. In addition, the positive reinforcement provided by a "carrots only, no sticks" approach facilitates customer acceptance, since it will guide them towards understanding dynamic rates without the possibility of a higher bill.

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[74] AB1X refers to Assembly Bill No. 1 from the 2001-2002 First Extraordinary Session as codified by Water Code section 80000 et seq. Water Code section 80110 protects the rates of residential customers for usage up to 130% of baseline quantities "until such time as the [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation's retail end use customers…."

[75] In D.06-07-027, the Commission ruled that residential customers may waive their AB 1X protections to participate in voluntary tariffs that give customers an opportunity to lower their bills.

[76] According to PG&E, an affirmative waiver of AB 1X protection for the PTR program would be unnecessary because (unlike with CPP) there is no potential for charges to increase for usage billed at Tier 1 or 2 rates; customers who do not earn a rebate simply continue to pay their normally applicable rate.

As with the CPP program, PG&E proposes to restrict eligibility to individually-metered bundled service customers. Master-meter accounts would be excluded from the program because it would not be possible to determine load reductions for individual tenants. Net-metered accounts would be excluded from PTR because these customers' loads are served by a combination of their own equipment and utility generation, and it would not be possible to evaluate demand reductions for such customers independently of changes in output from their customer-owned generation equipment. Finally, direct access and community choice aggregation customers would be excluded from PTR (just as they are excluded from participating in CPP), because the generation portion of their service requirements is provided by third parties.

PG&E has evaluated potential interactions between the CPP and PTR programs, with the expectation that customers may want guidance in helping choose between these two demand response participation options. Its analysis shows that customers who are believed to have significant central air conditioning (CAC) usage would divide almost equally between finding CPP vs. PTR participation most advantageous. Also, nearly 90% of customers who are not believed to have significant CAC usage would be better off on CPP than under PTR. Nonetheless, PG&E does not expect high levels of initial CPP enrollment from customers without CAC, because non-CAC customer savings under CPP would still be relatively modest and because PG&E's marketing efforts for CPP will be focused on customers with significant CAC loads.

PG&E explains that customer bill savings associated with the PTR program will be attributable to two factors: "structural" savings, and savings attributable to actual demand reduction efforts undertaken in response to PTR calls. Structural savings are sometimes referred to as "free rider" savings. In the context of the PTR program, these are rebates that customers would receive as a consequence of ordinary variation in their daily energy usage (e.g., if they happen to be on vacation on the day a PTR event is called, but were home during the period reflected in their CRL allowance). Customers will realize additional bill savings under the PTR program if they initiate real demand reduction efforts in response to PTR calls. In practice, each customer will realize a combination of bill savings under PTR (structural and demand response), although such effects must be estimated statistically and could never be measured independently for each household.

PG&E proposes to estimate the structural component of PTR savings for the residential class, using the best available load research information when rate updates are prepared for January 1 rate changes each year. This structural savings estimate would then be treated as an external adder to the residential class cost allocation for the purpose of setting generation rates, so as to prevent non-residential customers from having their own rates affected by the cost of the free-rider portion of rebates received by residential customers. (The first such estimate would be prepared in the fall of 2010 and will then be reflected when rates are set for January 1, 2011.) After providing for this adjustment for the structural component of the rebates, PG&E proposes that all actual rebates be recognized as reductions to revenues from generation rates. This approach is based on an assumption that the demand response component of PTR bill savings will be in reasonable accord with procurement cost savings that can be attributed to the program.[77]

10.1.1. DRA's Position

DRA recommends that approval of the proposed PTR program should be separated from a review of PG&E's proposed AMI Upgrade system. DRA recommends

[77] According to PG&E, this approach will reduce revenue accruing to the Utility Generation Balancing Account (UGBA) by the demand response component of PTR bill savings (total PTR rebates net of the free ridership adjustment), simply because the UGBA is the generation-related account to which revenues accrue residually. This may produce a modest mismatch between generation-related accounts, since PTR-related procurement savings would most likely be realized as reduced costs in the Energy Resource Recovery Account (ERRA). PG&E states that while this is a factor which PG&E and the Commission might wish to weigh when reviewing future UGBA and ERRA balances, it would not affect total generation rates or the division of costs between different groups of customers.

that the Commission approve the PTR program with modifications in the 2009-2011 Demand Response Programs and Budget Application.

Regarding program design, DRA recommends that the Commission adopt a two-level incentive structure to minimize free-ridership, as DRA recommended for SCE and SDG&E's PTR program proposals, and as adopted by the Commission for SDG&E's PTR program in D.08-02-034. Furthermore, PTR program measurement and evaluation should conform to the demand response load impact protocols adopted in D.08-04-050. Specifically, DRA emphasizes the ex post assessment of free-ridership and the distribution of load impact across customers.[78]

PG&E opposes DRA's proposal to address PTR in PG&E's 2009-2011 demand response (DR) program case. According to PG&E, the 2009-2011 DR case is a consolidated proceeding for PG&E, SCE and SDG&E and it needs to move forward expeditiously to allow the next cycle's DR programs to proceed in time for customers (primarily commercial and industrial) to know what will be offered and to decide whether they will participate. PG&E states that adding the DRA PTR proposal to that case would unreasonably delay the timetable and expand the scope of the 2009-2011 proceeding.

PG&E notes that the SDG&E and SCE PTR proposals have been moved to those utilities' respective GRCs, but if PG&E's PTR were moved to Phase 2 of its next GRC, implementation would be delayed beyond summer 2010, the program start date. PG&E also notes that the Commission specifically stated that PG&E's Upgrade case is an appropriate forum to consider PTR.[79]

With respect to DRA's proposed program design, PG&E states that DRA's proposal is flawed conceptually and lacks critical details. In the absence of any presentation of these details, the DRA recommendations should be rejected.

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[78] DRA's recommendation is detailed in Exhibit 108, Ex. 5, Ch. 5B.

[79] *See* D.08-07-045, Conclusion of Law 23. D.08-07-045 addresses the dynamic pricing phase of PG&E's last Phase 2 GRC.

DRA's description of its higher and lower PTR incentives raises the potential for the higher PTR incentive to exceed avoided cost, which PG&E cautions should not be allowed to happen. PG&E is also concerned about practical issues for establishing, enforcing and monitoring a two-tier incentive program. For instance:

- How will the required technology measures be identified (and updated)?
- How will individual customers' adoption of such measures be known and confirmed?
- How would continued on-going operation of installed measures on the customers' individual premises be monitored?

PG&E also notes the additional costs to implement, market and administer a DRA two-tier, technology enabled PTR program, beyond what PG&E has requested for a single-tiered PTR incentive.

10.1.2. Discussion

We believe the PTR program will encourage residential customers to reduce their peak period usage on peak days. We also agree that the program is allowable while the AB 1X rate protections remain in place. However, the PTR program should be regarded as a transitional program that the Commission intends to review when the AB 1X rate protections change.[80]

As discussed in other parts of this decision[81] the costs and benefits of PG&E's proposed PTR program will be considered in the cost effectiveness analysis of the Upgrade. We would also prefer to address the program design as part of this proceeding.

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[80] D.08-07-045 orders PG&E to "file an application proposing a default CPP rate for residential customers 30 days after any change in the law that changes the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers. If the Commission approves a decision that interprets the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers, then PG&E shall file an application proposing a default CPP rate for residential customers not later than 90 days after the Commission decision goes into effect and is no longer subject to rehearing or judicial review."

[81] See Sections 7.7 and 10.2.4.

As DRA indicates a two-tier design has been adopted for SDG&E.[82] Also, a two-tier settlement proposal for SCE has been deferred to SCE's Phase 2 GRC proceeding.[83] We are therefore reluctant to move forward with PG&E's single tier proposal. In other sections of this decision, we emphasize consistency in how we treat the IOUs. We see no reason to stray from that principle in this instance and will adopt a two-tier design for PG&E. However, we do acknowledge that the details of DRA's proposal are lacking and there are a number of practical considerations that would need to be addressed. For that reason, we will defer the PTR program design to PG&E's November 2009 rate design window filing, where we will require PG&E to propose a two-tier PTR incentive design and the associated PTR program costs for such a design. This will allow PG&E time to (1) work with DRA and other parties to work out program details and costs; (2) consider the adopted design for SDG&E along with any solutions to practical considerations, if any; and (3) monitor and evaluate what has happened or will happen in SCE's Phase 2 GRC with respect to implementing a two-tier PTR program design. Hopefully, this cooperative effort will allow time for the Commission to adopt and implement a two-tier design for PG&E in time for the anticipated Summer 2010 start of the program. If it turns out that this is not possible, PG&E's PTR program should instead be implemented in 2011. PG&E's rate design proposal should be consistent with the rate design guidance adopted in D.08-07-045.

10.2. PTR Benefits

The PTR benefits are calculated by PG&E with the same price elasticities as the CPP program using the model developed from the AMI business case in A.05-06-028. The model in this application assumes a total participation rate on both PTR and CPP of 50 percent of the residential customer sector based on PG&E's proposed awareness

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[82] *See* D.08-02-034, p. 22.

[83] *See* D.08-09-039, p. 38.

marketing. Estimated CPP participation is subtracted out annually and the residual MW reduction is estimated as the incremental DR benefit attributable to the PTR program. PG&E forecasts avoided capacity of 6,307 MW through 2030. PG&E values the avoided generation capacity costs at $85/kW-yr.

10.2.1. DRA's Position

In considering the demand response benefits PG&E attributes to the Upgrade proposal, DRA argues that the Commission should consider the metering functionalities needed to implement the proposed PTR program, and compare that to the added functionalities offered by the Upgrade. Specifically, if PTR implementation does not depend on the added functionalities, particularly the HAN gateway and the integrated service switch, then the PTR costs and benefits should not affect the Upgrade cost-benefit analysis.

DRA states that to implement a Peak Time Rebate program as PG&E has proposed, PG&E needs to do the following:

(1) Notify customers the day before a peak event day, and

(2) Collect interval customer usage data, and compare usage on the event day to average usage of the previous three-of-five days.

DRA examined Commission records and PG&E's original AMI application prepared testimony exhibits, and concluded that the listed requirements for the proposed PTR program can be met with the already authorized AMI system, without the added Upgrade functionalities. DRA recommends that the $290 million PG&E includes in its benefits calculations for PTR should therefore be excluded.

In response to DRA, as well as TURN who makes essentially the same recommendation, PG&E states that both DRA and TURN completely fail to recognize the value of HAN and IHDs to reach more customers and communicate most effectively with them, which is necessary to achieve the desired result of an effective PTR program.

10.2.2. TURN's Position

TURN believes that any benefit from PTR rates is not incremental to the hardware requested in this application but could be obtained (albeit at higher marketing and IT cost) from the functionality specified for existing hardware. In the event that demand response benefits from PTR are considered, it is TURN's position that those benefits, as estimated by PG&E, have been significantly overestimated. TURN provides three basic reasons for this position.

First, TURN calculates an AC adjustment factor to incorporate its assertion that AC loads will be decreasing over time as more efficient air conditioners are installed according to federal regulations. According to TURN, the movement from an average SEER[84] rating of SEER 10 to SEER 13 at the end of 20 years means that the stock of CAC units will result in less demand per unit over time, thus a smaller starting point from which to undertake demand response. TURN argues that use of its SEER rating adjustment is more appropriate than PG&E's position of no AC adjustment.[85]

Second, TURN argues that PTR demand response calculated with the use of unadjusted CPP elasticities will overstate response from PTR rates.

From a theoretical perspective, TURN argues that *a priori* one would expect customers to consume less under a CPP rate than under a PTR rate. That is because under a CPP rate, the charge on each kWh consumed during the peak period on an event day is the OAT plus the CPP adder of 60¢/kWh. So if the OAT is 16¢, a customer would be charged 76¢ for each kWh consumed during the peak event (a "stick," accompanied

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[84] SEER is the Seasonal Energy Efficiency Rating, defined by the Air Conditioning and Refrigeration Institute. Higher SEER ratings are more energy efficient.

[85] TURN states that while its witness, Ms. Schilberg, conceded upon cross-examination that the AC adjustment factor could involve a slightly smaller derate than appears in TURN Ex. 211, p. 16, the AC adjustment factor was erroneously omitted from its adjustments to the expected PCT MW. TURN states that it considers these two factors to be offsetting, and this decision assumes that TURN's total SEER related adjustment is reflected in its PTR adjustment.

by a "carrot" of tariff reductions on other kWh consumed). Under a PTR rate, the customer is charged the OAT on each kWh consumed during the event peak period (e.g., 16¢), but receives a credit of 60¢/kWh for each kWh saved compared to a reference level. TURN states that while the marginal incentive to save a kWh is the same between the CPP and PTR rates, the marginal price to consume a kWh is far higher under the CPP rate (76¢) versus the PTR rate (16¢). TURN interprets this to mean that the consequence of peak consumption under CPP rates is likely to be more attention-getting for the customer, and that expensive consumption will run into the customer's budget constraint. On the other hand, the customer under PTR rates faces no adverse consequence from continuing to consume, and that extra consumption at the lower OAT does not impact budget constraint."

TURN also argues that quantitative evidence supports the theoretical understanding that CPP customers will save more energy than under PTR rates. According to TURN, the only study that examines both rates, using the same incentive for CPP and PTR on the same days (same weather), is the Ontario study.[86] In that study customers under PTR rates saved 30% less than CPP customers. TURN states that although the statistical results do not enable a conclusion that the CPP and PTR savings rates are statistically different from each other, the lower PTR value supports TURN's theoretical understanding and is evidence that must not be discarded lightly. For these reasons, TURN recommends that it would be reasonable to adjust the CPP elasticities downward by 30 percent for PTR purposes.

TURN also argues that evidence from customer surveys supports its position that PTR customers will save less than CPP (SmartRate) customers. In citing a recent PG&E

[86] IBM Global Business Services and eMeter Strategic Consulting for the Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report" July 2007.

study,[87] TURN states the survey shows that 22% of customers were interested in signing up for CPP rates, and that they are "more involved in energy than the average customer – they are more motivated to conserve, they want more control, and they are more receptive to getting help from PG&E to reduce their energy use further…tend to be under 55 years old, higher educated, more affluent, with families, with higher than average energy bills…" Also, although 47% of customers said they would sign up for PTR (SmartRebate), they are "less interested in controlling their energy use, they are less likely to think they can reduce their energy use weekday afternoons without too much inconvenience, and they are less likely to want to think about or track their energy use. SmartRebate customers also differ demographically from those who say they would sign up for SmartRate. Both groups tend to be customers who are under 55 years old, but in nearly all other respects customers interested in SmartRebate are very much like the average of all customers. They do not stand out in any respect other than being somewhat more likely to be on the CARE rate." According to TURN, it is clear from the customer surveys that those signing up for the PTR rate will be far less interested than CPP customers in saving energy and thus will not produce the same savings that can be expected from CPP customers.

Also, TURN expects that participation in PTR will fall off over time, because (1) customers value financial savings, and the small savings available will not maintain participation in the long run; (2) a disadvantaged customer needs to reduce energy by more than 15% before even earning a rebate on at least one-third of the event days, which will defer many customers; and (3) default PTR customers are not committed to demand response.

TURN also disagrees with PG&E's assumption that its notification strategy will reach 50% of the residential customers regarding critical peak time events for PTR and

[87] Hiner & Partners, Inc., "Pacific Gas and Electric Company 2007 Rate Option Survey,"

Footnote continued on next page

CPP rates combined. TURN indicates that while PG&E expects to provide direct notification to customers of event days via devices such as in-home displays beginning in 2013, PG&E expects that market adoption of the in-home display will reach 3% of customers by 2013 and top out at 30% of customers in 2024. TURN argues that even at maximum penetration (30%) the in-home displays cannot be relied upon to assure 50% awareness for PTR/CPP rates in the near future.

TURN also states that the fact that PG&E intends to make 50% of its customers "aware" of critical peak events is not an assurance that 50% of its customers will behave as did customers who were enrolled in the SPP pilot. While TURN did not make an additional adjustment for this factor, it states that this is another source of overestimates in PG&E's projections, which the Commission should keep in mind in judging the merits of PG&E's demand response benefits.

Also, as a consequence of PG&E's 50% participation assumption, TURN understands that PG&E implicitly assumes 45% of its non-CAC customers will participate in PTR.[88] TURN states that expecting these customers to participate in PTR for the next 20 years is not supportable because (1) non-CAC customers have small usage; (2) financial savings from demand response are small; and (3) non-CAC customers are unlikely to have in-home display devices. TURN states that PG&E has no basis for assuming demand response of 104 MW from non-CAC customers in 2012, up to 129 MW in 2027. Since SPP data show that roughly 26% of participants identified non-financial reasons for their participation, TURN expects that participation in PG&E's PTR program is like to be a maximum of 26% of non-CAC customers, rather than the 45% PG&E assumes (adjustment factor = 58%).

August 2007.

[88] Exhibit 211, p. 18.

In summary, TURN expects a maximum of 142 MW from PTR in 2012 (55% of PG&E's 260 MW estimate), and 162 MW in 2025 (49% of PG&E's 328 MW estimate).

In response, with respect to TURN's assertion that increases in federally mandated SEER from 10 to 13 would increase the energy efficiency of CAC units while higher saturations of "more efficient" CAC units would reduce the peak demand response potential from future CAC installations and retrofits, PG&E states that TURN's argument ignores a well-established body of evidence that SEER is not a reliable predictor of energy performance in California or of demand reduction. PG&E states that the CEC report cited by TURN for the increase in SEER ratings is replete with statements about the inadequacy of SEER ratings in California. For instance, the CEC report states: [89]

> Current HVAC appliance performance testing is conducted to national standards. Standard ratings for the seasonal energy efficiency ratio (SEER) are conducted at a maximum temperature of 82° Fahrenheit and treat dehumidification as equal to sensible cooling. In the hot dry climates of California, outside air temperatures over 95° Fahrenheit with 35% relative humidity is common. The current standards provide inaccurate assessments of energy requirements during peak periods in California and the Southwest.
>
> Peak energy use is further amplified by the natural tendency of designers and contractors to provide a larger capacity system than necessary, resulting in excessive and inefficiency cycling of the compressor. Increased cycling of a direct expansion air conditioning system reduces overall efficiency through cycle start-up losses which occur until the cold liquid refrigerant returns to the evaporator coil. The results of over sizing single-speed units include increased electric peak and, in some cases, increased energy consumption.

PG&E indicates that the bottom line of the CEC report cited by TURN is that:[90]

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[89] See PG&E, Ex. 25, p. 24.

[90] *Id.,* p. 25.

> [T]he state should investigate a new efficiency metric for residential and nonresidential direct expansion, air cooled air conditioning system that appropriately rates performance in hot and dry California climate zones.

PG&E also states that Exhibit 218 that was introduced by TURN echoes the findings of Exhibit 25, wherein it states, "Neither SEER nor EER is a sufficiently reliable indicator of cooling energy performance (consumption or demand) for California."[91]

With respect to TURN's proposed 30% reduction in SPP elasticities, PG&E states that the standard error for both the CPP and PTR Ontario study results was 8%, and:

> Thus, the difference between the two values is less than one standard deviation, which is much less than the two standard deviations required to demonstrate that the difference is statistically significant. Put another way, the empirical evidence from the Ontario pilot does not support the claim that the impacts estimated using the SPP demand models should be reduced by 30%—indeed, the empirical evidence shows that there is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population.[92]

PG&E also points out that the Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the demand models from the SPP (after controlling for air conditioning and climatic differences between the Anaheim and SPP samples), and the convergence of the Anaheim PTR results and the SPP model results corroborate the Ontario study's finding of no significant difference between PTR and CPP impacts.

With respect to TURN's argument that non-CAC customer usage is small and savings will be small, PG&E argues that, while the average PTR benefit for a non-CAC customer may be small, there are a range of customers both above and below the average with many distributions possible. PG&E indicates that if the average benefit were $1.50

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[91] Exhibit 218, p. 25.

[92] PG&E, Exhibit 8, p. 9-3.

per month, there could be scenarios where half the customers reduced load enough to get a $3.00 saving or where 25% of the customers respond sufficiently to get a $6.00 bill savings. Moreover, if the customers are in tiers 4 or 5, their savings could even be greater.

With respect to TURN's assumption that a customer must purchase an IHD to participate in PTR, PG&E indicates that it has budgeted funds to provide continued support of education and event notification, such as public service messages and press releases. Thus, according to PG&E, although IHDs are critical as an additional notification channel, a portion of PG&E's customers (particularly in high density urban areas like the San Francisco Bay Area) may learn about PTR events through other media. PG&E does agree that a large percentage of customers will participate for environmental or societal reasons, but does not agree that participation for non-CAC customers should be limited to only that group.

10.2.3. CCSF's Position

CCSF agrees with DRA that PTR implementation is not dependent on real time communication with customers. According to CCSF, using PG&E's website or the media to send out notices of a PTR event could be just as effective as PG&E providing notice through its customers' IHDs, and the added functionalities provided by the HAN are not an additional benefit of PG&E's proposed AMI upgrade.

The City also agrees with TURN, that there is no evidence to support PG&E's claim that its customers will respond to PTR rates in the same way they do to CPP rates.

10.2.4. Discussion

With respect to DRA's position, as indicated previously in this decision, we are accepting PG&E's definition of "incremental" for purposes of determining Upgrade costs and benefits. Since PTR benefits result from PG&E's SmartMeter project and were not quantified in PG&E's original AMI proceeding, we will do so now as part of determination of the cost effectiveness of the Upgrade.

With respect to TURN's recommended adjustments, in the event that PTR benefits are considered, we agree, to an extent, that demand response related to PTR will likely be less than that estimated by PG&E.

PG&E has provided persuasive evidence to justify its position that SEER is not a reliable predictor of energy performance or of demand reduction in California. We interpret that to mean, for instance, if a customer upgrades from a unit with a SEER 10 rating to a SEER 13 rating, which reflects a 30% increase in the rated efficiency of the equipment, the customer will probably not realize a 30% reduction in demand or 30% energy savings. Demand reduction and energy savings will likely be lower. However, we do not interpret this to mean there will be no energy savings or reductions in demand at all. For example, in Exhibit 218, Figure 12 shows median savings, ranging from 6% to 33%, associated with upgrading from a lower SEER system to a higher SEER system under different upgrading scenarios, although the number of units achieving expected savings is low (from 8% to 29%). Therefore, even though the climate and other factors particular to California are not the same as that assumed for SEER purposes, it is reasonable to assume that as manufacturers attempt to make more efficient systems to comply with upgraded SEER levels, there will be some effect of demand reductions and energy savings in California. We will reduce TURN's proposed adjustment by 50% to reflect this effect.[93]

With respect to TURN's proposed 30% elasticity adjustment, we are convince by PG&E's arguments that there is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population, and the Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the

[93] TURN assumed a 30% increase in efficiency when moving from SEER 10 to SEER 13. Based on the information in Exhibit 218, Figure 12, and the general concerns related to using SEER for such purposes, a 15% increase in efficiency appears reasonable.

demand models from the SPP. We will therefore not adopt TURN's recommended adjustment. This is consistent with our actions in SCE's AMI proceeding where a similar TURN proposal was rejected and where we stated:

> Current evidence does not provide a definite picture of customer behavior under a PTR rate, since such rates are not currently in widespread use. However, based on existing evidence it is reasonable to conclude that the elasticity of customer electric demand under a PTR rate may be comparable to under a CPP rate. Similarly, though it is not possible to be certain how customers will react to a PTR rate on a long-term basis, it is reasonable to apply economic theory to this question and assume that long-run elasticities will not be lower than short-run elasticities. Over the long run, for example, customers may have access to more enabling technology allowing them to respond more easily to PTR rates and increase their resulting demand response. For these reasons, the elasticities used in the settlement agreement business case, which are based on elasticities calculated from CPP rates and are assumed to remain stable over time, are reasonable for the purposes of estimating future energy savings from PTR rates and their associated benefits.[94]

With respect to TURN's non-CAC customer participation adjustment, we understand TURN's concerns regarding limited savings. While PG&E demonstrates that a non-CAC customer might realize significant savings under the PTR program under certain scenarios, there is no evidence as to suggest what the expected scenario might be and what savings would result from such a scenario. We do agree that there will likely be a response beyond that of those who would participate for environmental or societal reasons and assume for purposes of this analysis that it is halfway between that estimated by TURN and that implicit in PG&E's forecast. This results in a non-CAC customer participation rate of 35.5%.

Based on the above discussion, we adopt PTR savings through 2030 in the amount of 5,714 MWs as opposed to PG&E's forecasted amount of 6,307 MWs. This results in a

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[94] D.08-09-039, p. 30.

PVRR benefit of $262,941,000 as opposed to the PG&E's $290,222,000 estimated amount.

10.3. TURN's Demand Response Guarantee Proposal

In TURN's opinion, the implementation of a PTR rate is likely to undermine customer participation in the CPP rate which was approved in D.06-07-027, and there is a danger that the benefit stream upon which approval of the initial AMI project was based will not be fully realized. Also, TURN estimates demand response benefits that are 40%-49% of the MW that PG&E projects, reducing projected benefits by at least $222.5 million. For these reasons, TURN believes there is a significant probability that not only will the benefits of this application not be realized, but also the benefits approved in D.06-07-027 will be diminished. It is TURN's position that failure to fully realize the projected demand response in both projects – the initial AMI project and the Upgrade--doubly harms ratepayers by not only saddling them with costs that are not accompanied by benefits, but also requiring ratepayers to purchase expensive power at peak times to replace the unrealized demand response. TURN also indicates that, because demand response and conservation benefits account for 85% of the Upgrade benefits, failure to achieve 100% of these amounts has a large impact on the benefit/cost ratio.

In light of these considerations, TURN recommends that, if the Commission proceeds with any part of PG&E's Upgrade application, PG&E should be required to adhere to the following guarantee:

> Failure to achieve 65% of the MW savings approved in D.06-07-027, and 100% of the additional PTR and PCT MW projected in this application (see Table below) should result in penalty payments to ratepayers. The penalty should equal one-half of the annualized cost of a peaking powerplant adjusted for losses (and for reserves if applicable at the time) multiplied by the unachieved savings for each year of underachievement.

In summary, PG&E opposes TURN's penalty proposal as inappropriate in this case. First the time, effort, expertise and focus needed to address the complex issue of shareholder risks and rewards for demand response is beyond the scope of this proceeding. Second, TURN's penalty-only proposal is arbitrary and has no sound justification. And third, as the Commission did not adopt this type of mechanism in its original decision on PG&E's AMI application, it would be unreasonable to introduce a penalty mechanism now, two years later.

PG&E adds that forecasts of avoided costs, other costs, benefits, and the metrics for measuring them out into the future should be expected to change over time, with more experience. For instance, the Commission may institute new programs that take advantage of the upgraded elements of PG&E's SmartMeter system to obtain new benefits.[95] PG&E points out that the Commission has extensive review and approval oversight for demand response, where it can take corrective steps that may be appropriate at the time. PG&E also notes that future increases in the economic value of the demand response could produce values exceeding those estimated in this case, even if the forecasted MWs are not achieved. So, under TURN's MW approach, PG&E could be penalized even though the value of the demand response achieved was higher than forecast in the case.

10.3.1. Discussion

We will not adopt TURN's demand response guarantee proposal. First of all we have adjusted PG&E's PTR and Title 24 PCT program benefit estimates to what we feel are reasonable levels, in light of the record of this proceeding. Also, a similar issue was addressed recently in SCE's AMI proceeding, where TURN proposed that the Commission should also adopt a penalty mechanism under which SCE would be required to pay a penalty in the event that it failed to reach 65% of its forecast demand response. TURN recommended a penalty mechanism equal to one-half of the annualized cost of a

[95] PG&E points to the requirements for PG&E's February 2009 rate design window filing contained in D.08-07-045 that suggest that the Commission has more dynamic rate options in mind.

peaking power plant adjusted for losses and multiplied by the unachieved savings. In resolving the issue, the Commission stated:

> As discussed above, any forecast of costs and benefits that goes out far into the future is subject to great uncertainty. We approve the settlement agreement based on the best available current information, but many of the rates and programs assumed for the purposes of the business case have not been adopted by the Commission, and must ultimately be considered on their merits when specific proposals are made. Similarly, we have used the best available estimates for program participation in the business case analysis, but because CPP and PTR rates are not currently in widespread use for residential customers in California, these estimates, too, are subject to uncertainty. Future information on customer behavior in response to these or other dynamic rates may provide more accurate information on participation rates and demand elasticities, but we must analyze the settlement agreement based on the information available today. For these reasons, it is not reasonable to penalize SCE for failing to meet the forecasts made in the business case.
>
> It is, however, reasonable and desirable to determine how closely the demand response, conservation, and load control forecasts, and forecasts of associated benefits, match the forecasts made here. The collection of data the actual demand response achieved with the AMI system will provide us with valuable information on customer behavior, and enable us to track progress towards state energy policy goals associated with AMI, DR, and related issues. For this reason, in addition to approving the settlement agreement, we require SCE to report to the Commission on the energy savings and associated financial benefits of all DR, load control, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers. SCE should work with Energy Division develop a reporting format for this information, and should file annual reports in April of each year in R.07-01-041 or a successor proceeding until April 2019. If no successor proceeding exists, SCE should send these reports to the Director of the Energy Division and serve the service list of the most recent Commission demand response rulemaking. To the extent possible, SCE shall base its estimates of energy savings on the Commission's adopted load impact

protocols contained in D.08-04-050 or successor protocols adopted in the future.[96]

The reasons expressed by the Commission for rejecting TURN's penalty proposal in SCE's AMI proceeding are applicable here. We have reviewed the record in this proceeding and have adopted what we consider reasonable estimates based on that record. It would not be appropriate to penalize PG&E, if the adopted demand response does not materialize.

Similar to what was required for SCE in D.08-09-039, PG&E should report to the Commission on the energy savings and associated financial benefits of all DR, load control, energy efficiency, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers. If not already included, these requirements are supplemental to the PG&E's reporting requirements mandated by D.06-07-027. PG&E may request recovery for the cost of this reporting requirement in appropriate cases.[97]

10.4. PG&E's Proposed Title 24 PCT Program for Residential Customers

In its December 12, 2007 application testimony PG&E indicated that new Title 24 building code air conditioning standards were expected in 2009. The new standards would require all new homes and retrofits requiring building permits for central air conditioning and heating to have Title 24 compliant PCTs installed. PG&E would then target residential customers with the new PCTs for participation in PG&E's SmartAC Program. PG&E would also create a program to encourage existing air conditioning customers to initiate early retrofit of their standard thermostat with Title 24 compliant PCTs. However, the CEC withdrew its Title 24 building code air conditioning standards

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[96] D.08-09-039, pp. 52-54.

[97] If PG&E requests such recovery, it must fully justify the costs and the incremental nature of the costs.

recommendation shortly after PG&E filed the application. PG&E now assumes the standard will be implemented in 2012 and that PG&E will begin recruiting new construction and permitted replacement/retrofit customers in 2013. PG&E states that all of these customers will be seamlessly integrated into PG&E's existing SmartAC Program, although the temperature set points, event notifications, and the ability for customers to override events will be communicated through the HAN gateway.

Under PG&E's proposal, PG&E's existing SmartAC Program will continue to operate as designed including the option as an enabling technology for a pricing program. All eligible SmartAC customers will be able to enhance their participation in CPP or PTR with the enabling technology provided on the SmartAC Program, including those joining the program through the proposed Title 24 PCT program. PG&E will offer to adjust participating customer air conditioning on the event days.

The Title 24 PCT program assumes the SmartAC Program will continue, but IT costs associated with the implementation via the HAN gateway device and using internal customer tracking systems are included by PG&E in this proceeding. Additional assumptions by PG&E include:

- ffi All new residential construction with AC would have a Title 24 compliant PCT installed (based on the Residential Appliance Saturation Study (RASS),[98] 75.5% of new homes are assumed to have AC);[99]

- ffi 38,000 or 38% of the expected number of 100,000 major home remodels assumed to have AC (based on the RASS);

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[98] California Statewide Residential Appliance Saturation Study Update to Air Conditioning UECs Using 2004 Billing Data Final Report, prepared for California Energy Commission (400-04-010), KEMA-XENERGY, May 2006.

[99] New construction annual population estimates are calculated by applying climate zone growth rates and population counts consistent with those included in A.05-06-028, PG&E-4, Table 2-4 and 2-5, p. 2-10.

- Only 70% of heating, ventilation and air conditioning (HVAC) replacements or retrofits would be done with building permits, and that only the permitted retrofits would have Title 24 compliant PCTs installed;

- 25% of residential customers with a Title 24 PCT will enroll in the program based on a $25 incentive and the opportunity to lower peak time energy usage and save money on critical event days;

- The average number of AC units per customer is 1.08 based on recent SmartAC Program experience;

- Average of 0.75 kW per PCT consistent with PG&E's existing SmartAC Program impact estimates;[100] and

- A 15-year life of the PCT.

In addition, for the early retrofit of existing air conditioning systems with Title 24 compliant PCTs, PG&E will target 30,000 customers a year with an enrollment cap of 250,000 customers. Since PG&E's current SmartAC Program is approved for up to 305 MW of demand response, the Title 24 PCT benefits claimed for Upgrade are only for demand response MW amounts above the 305 MW level.

PG&E's Upgrade demand response benefits include reductions of 3,738 MWs from 2013 through 2030 for demand response from Title 24 PCTs. Using an avoided capacity cost of $85 per MW, PG&E calculates PVRR benefits of $129,401,000.

[100] PG&E states that consistent with the SmartAC impact estimates is the assumption the 30% of residential customers will also participate in a dynamic pricing option, and therefore the average technology impact of 1.1 kW is expected to eliminate double counting of demand benefits with CPP or PTR.

10.4.1. DRA's Position

DRA states that PG&E has already counted the participation of new customers in its SmartAC program and has thus excluded Title 24 PCT benefits from its cost effectiveness analysis of the Upgrade.

Also, DRA questions whether PG&E can "seamlessly integrate" the HAN functionality with its SmartAC program operation as it claims. DRA states that operating the SmartAC program through the HAN interface does not mean that PG&E can replace the 900 MHz paging system approved for its SmartAC program, and quotes the following from PG&E's Upgrade testimony:

> Separate communications systems are likely to be necessary due to the possibility that customer-owned equipment installed under the current SmartAC program may not be able to communicate with the new HAN network.[101]

Consequently, DRA argues that PG&E may not be able to operate all AC units participating in its SmartAC program through the HAN interface.

DRA notes that, as approved in D.08-02-009, PG&E has a communication system to remotely control PCTs. To promote interoperability, the CEC also considered requiring the PCTs to incorporate "communication expansion ports," to allow for remote control of the PCTs via other communication systems, such as the 900 MHz paging system for which PG&E received ratepayer funding in D.08-02-009. According to DRA, even if the CEC were to revert to mandate Title 24 PCT in new construction, its focus on technological interoperability (which both DRA and PG&E have publicly supported) would likely persist. In DRA's opinion, the Upgrade would not add an incremental functionality to PG&E's existing demand-side management system, beyond what PG&E could already achieve with its functionality claims in the AC Cycling and the original AMI applications.

[101] PG&E, Exhibit 3, p. 4-4, footnote 2.

In response, regarding DRA's double counting argument, PG&E notes that DRA's witness acknowledged that the AC Cycling settlement provided for up to 400,000 devices to provide 305 MW of demand response, including additions to cover attrition to maintain 400,000 devices in the program.[102] PG&E also indicates that its testimony also recognized that the A/C settlement was to install 305 MW of dispatchable demand response from 2007- 2011, with a cost/benefit analysis for the 15-year life of the program technologies. However, PG&E asserts that CAC cycling beyond the A/C settlement scope is needed to address increased demand from new construction over the Upgrade period. According to PG&E, its Upgrade cost/benefit analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement.

Regarding DRA claims that technological interoperability issues with Title 24 PCTs may interfere with PG&E's ability to operate AC units through the HAN interface, PG&E notes, as did DRA, that the CEC has considered requiring the PCTs to incorporate other communication systems. PG&E states that industry participants certainly are promoting HAN communication to CEC staff for this purpose, and the fact that the two southern California investor-owned electric utilities will have HAN systems, plus PG&E if the Commission approves this application, may move the market, making HAN communication a sensible element of Title 24 PCTs.

10.4.2. TURN's Position

TURN states that the PCT devices should be attributed zero benefits in this application, because PCTs are not incremental to the hardware requested in this application. PG&E already has a SmartAC program involving PCTs that can achieve demand response without the necessity to approve this application.

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[102] DRA, Lee, 5 RT 718-719, 723.

Also, TURN asserts that PCT demand response will be significantly less than anticipated by PG&E for the following reasons:

- ﬃ Although PG&E assumes that PCT program participants will save on average 0.75 kW per hour per event, data from PG&E's 2007 SmartAC program (which offers either a one-way communicating PCT or AC cycler) predicts only a 0.48 KW impact for PCTs.

- ﬃ Based on data from a ramping strategy that sets back the thermostat by 4° at the beginning of the event period, evidence from DOE modeling shows that a residential thermostat's impact on savings goes from 0.42 kW/ton in the first hour (2:00 p.m.) down to 0.25 kW in the fourth hour (6:00 p.m.). There is a snapback or rebound effect after the event ceases and the AC unit attempts to recover to its normal temperature setting. The full impact of the demand response does not last for four hours, as would be required for most resources that comply with resource adequacy (RA) requirements.

  PCTs measured in PG&E's 2007 SmartAC program also sometimes showed a reduction in savings in the last hour. As shown in Ex. 206, p. 5-36, Figure 5-3 shows lower per-unit average kW reduction in the last hour in three of the six scenarios examined (two ramping strategies, three days each).

- ﬃ Evidence from marketing surveys as well as marketing efforts supports a conclusion that it will be difficult for PG&E to achieve 25 % participation of PCT owners to receive temperature setbacks under its PCT program.

  TURN cites the 3.6% response rate from a marketing solicitation, stating that this result gives little confidence that PG&E would obtain 25% market penetration for its PCT program. TURN asserts that this is a long way from 25%.

  TURN also cites Greenberg research as evidence that PG&E would have difficulty reaching 25% participation. That research shows that customers with newer systems were negative about direct load control, feeling their equipment installation was a significant enough contribution to the energy shortage. TURN argues that the fact that the PCT is installed does not address at all the customer's reluctance to have it activated and to participate with temperature setbacks in the PCT program.

- For the 30,000 customers per year expected to voluntarily purchase PCTs and enroll in PG&E's PCT program, TURN states that the retail cost of the PCT device could be a barrier to participation. TURN states that PG&E did not provide an estimate of the cost of a two-way communicating PCT, and TURN calculated an estimate of between $90 and $120.

Also, TURN cautions that, in the event that the CEC does mandate PCTs, the cost to the homeowner of such a mandate will need to be offset with the benefit, e.g., the savings due to demand reduction. According to TURN, under this scenario PG&E cannot also count the value of the same demand reduction, as that would be double counting one benefit against two sets of costs in two different proceedings. TURN further states that PG&E's own assumption of only 25% of PCT customers actually participating in the demand reduction program lowers the likelihood that such a PCT mandate could even be cost-effective at the CEC.

TURN points out that alternatively PG&E could assume that no Title 24 mandate occurs, and include in the Upgrade project both the cost of a PCT as well as the benefit of the PCT demand reduction. This is the approach taken by SCE in its recent AMI proceeding (A.07-07-026), where SCE included a $50 charge for a PCT (in case there is no Title 24 mandate) and also included the benefit of the PCT demand response. PG&E states that, in the Upgrade, PG&E has not included a cost for the PCT as SCE did, and thus inclusion of the PCT DR benefit is not legitimate.

TURN asserts that its evidence justifies the following recommendations:

- The "Title 24" MW should be zero, even if PCTs are mandated elsewhere. A device could only be mandated if it were considered cost effective by the mandating agency, in which case the "benefit" of demand reduction will double count what PG&E proposes here. Otherwise the same benefit will be used to justify two sets of costs in two different venues. This reduces PG&E's projection by 40 MW in 2015 and 154 MW in 2025.

ffi For voluntary PCTs (PG&E's "non-construction" category), TURN expects the MW to be reduced by 33%, based on recent Smart AC evidence. This reduces PG&E's projection by 11 MW in 2015 and 41 MW in 2025. The cost of the PCT device, purchased by the customer, would need to be included in the TRC test. The high cost of a PCT device, relative to what PG&E proposes as an incentive to join the program, also causes TURN to doubt PG&E's projection for participation, although TURN has not imposed a separate adjustment for that factor.

Thus, for the years through 2030, TURN's projections are roughly 28%-37% of the annual PCT MWs that PG&E projects.

In response, regarding TURN's statement that the PCTs are not incremental to the "hardware" requested in the Upgrade case adding "PG&E already has a SmartAC program involving PCTs that can achieve demand response," PG&E states that TURN's later statement is not true for the Title 24 PCTs, as discussed in PG&E's response to DRA. As to the first statement, PG&E argues that TURN misses the point by asserting that PCTs should somehow be incremental to Upgrade equipment. According to PG&E, what matters is the Upgrade equipment's functionality with Title 24 PCTs. PG&E anticipates that the additional HAN functionality will be used with PCTs in the future for operation of CAC cycling during events for all three California investor owned electric utilities; and it is HAN's functionality that facilitates demand response with Title 24 PCTs which supports inclusion of the PCT benefits in this case.

In response to TURN's assertion that PCT demand response will be significantly less than anticipated by PG&E, PG&E provided the following reasons for rejecting TURN's analysis:

ffi Regarding TURN's attack on PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, PG&E indicates that the KEMA study referenced by TURN analyzed performance during the first summer of PG&E's A/C cycling program (2007) with 5,000 customers in the Stockton area. Differences between the demand reductions produced by switches versus PCTs were recorded, but those differences were primarily driven by how the program was operated, not by technology. PG&E witness Alexander reported that there were two ramping strategies with PCTs, both designed to overcome limitations of a single set point increase at the beginning of an event. Those strategies did not achieve the same load impacts as with switches. There are additional strategies that will be used in 2008. PG&E witness Alexander expects future ramping strategies and greater experience will lead to PCT load reductions comparable to switches. PG&E argues that it is not reasonable to discount potential PCT benefits based solely on the results of the limited operations of the startup program in a compact geographic area.

ffi With regard to TURN's questions of whether the demand response benefits from PCTs will last for four hours, PG&E states that TURN used a figure from PIER Buildings Program SCE Codes & Standards Program Workshop held early in 2006 to illustrate a steep drop in PCT impact near the end of the fourth hour. However, that table is the product of a DOE 2.2 model simulation, where the program is told to end by 6:00 p.m. Hence, according to PG&E, the model should be expected to produce a sharp drop in its simulated demand response by 6:00 p.m.

In response to TURN's statement regarding RA requirements, PG&E notes that demand response can count for RA if it is available for 48 hours per summer, or qualify as a two-hour resource if not more than 0.89% of the RA need. In effect PG&E is reserving the right for the PCT (and possibly other DR programs under consideration here) to provide a smaller value to ratepayers (only two hours rather than four hours per day). However PG&E states it has made no showing that the PCT program is the only two-hour resource that the company will consider, and that the 0.89% of capacity from two-hour resources is not already oversubscribed (in which case the RA value of two-hour PCT savings would be zero)

While TURN refers to Figure 5-3 in the KEMA report for the proposition that PCT demand response drops off, PG&E points out that what the KEMA report really shows is a positive relationship between the temperature and the demand reduction for PCTs, as well as the program in general, based on summer 2007 data. Moreover, according to PG&E, KEMA's analysis of the summer 2007 data found no statistical difference between the PCT drop-off and the switches. (Reporter's Transcript, p. 221, lines 5-18.)

ﬃ Regarding TURN's attack on PG&E's 25% participation assumption, PG&E states that the KEMA process evaluation cited by TURN was performed at the program's infancy, when participation had yet to reach 5,000. However, in less than a year, the program has grown to over 75,000 customers with the $25 incentive, and PG&E indicates that is well on its way to achieving the 25% market penetration target.

In addition, PG&E states that TURN's use of the Rate Option Positioning Research performed by Greenberg Brand Strategy in 2007 (Greenberg study) is inapplicable for Title 24 PCTs. The statement from the Greenberg study referenced by TURN reports that focus group participants with newer air conditioning systems were negative about changing equipment they had just installed. According to PG&E, this point is irrelevant for Title 24 PCTs required for new construction and permitted retrofits, because the PCTs would already be installed to comply with state building code standards. That code standard would neutralize the issue over time, and would help with several other customer concerns.

Regarding TURN's double counting argument related to how the CEC might conduct future analysis for new initiatives within its jurisdiction, PG&E states it is speculative and indicates that the CEC analysis TURN cites was done several years ago and includes assumptions of questionable relevance now. Also, PG&E states the CEC will have a number of input options that are not used in the Total Resource Cost (TRC) test at the Commission. For instance, the CEC might include customer bill savings and incentives from DR or rate programs in its analysis, although they are not part of a TRC analysis at this Commission. PG&E concludes that, since the CEC does things its own way, there is no way to know today what a future CEC analysis will depend upon.

10.4.3. Discussion

The threshold issue is whether or not to include PCT benefits in the cost effective analysis for the Upgrade. PG&E has produced evidence from which it can be concluded that its cost effectiveness analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement. We do not see double counting as alleged by DRA.

Also, we are not convinced by TURN's double counting argument involving future CEC actions. TURN has not listed the costs that would or might be assumed in such CEC actions that would need to be compared to a benefit such as demand reduction, and we do not know what they would be. There is also no evidence as to what the magnitude of those costs might be. Therefore, we have no way of knowing whether or not any future CEC assumed costs would significantly affect the cost benefit analysis as it applies to the Upgrade. We can only conduct our analyses with the information available and take factors such as CEC actions into account when they are known and relevant. It would therefore not be appropriate to completely dismiss the use of Title 24 PCT benefits in the Upgrade cost effectiveness analysis, as proposed by TURN.

For these reasons, we will include the PCT benefits in the Upgrade cost effectiveness analysis. However, while we will consider Title 24 PCT benefits as proposed by PG&E, we do agree with TURN that PG&E's estimates of MW savings may be excessive.

First, there is no certainty that the Title 24 regulations will be implemented in 2012, if ever. While PG&E assumes that date, there is no real evidence to substantiate it. There apparently was significant opposition to the regulation to the extent that it was eventually withdrawn. Whether such opposition can be overcome either in the short term or the long term is uncertain in our minds. If new construction and permitted retrofits are excluded from the benefit analysis for any length of time beyond 2012, the benefits will be reduced significantly.[103] PG&E projects some voluntary participants for this program. Whether the amount of voluntary participation will grow, if the Title 24 PCT regulations are not enacted, is uncertain.

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[103] As TURN indicates this issue was not as critical in evaluating SCE's AMI proposal, because SCE included both the cost of a PCT as well as the benefit of the PCT in its PCT demand reduction analysis. PG&E does not provide for the cost of the PCT, although it does provide a $25 rebate for this program.

There is also some uncertainty as to whether technological interoperability issues with Title 24 PCTs may interfere with PG&E's ability to operate AC units through the HAN interface.[104]

Regarding PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, PG&E gives a reasonable explanation of why 0.48 KW/hour savings may be low but provides no convincing evidence to justify its assertion that different ramping strategies will necessarily result in 0.75 kW/hour savings.

Whether PG&E's 25% market penetration rate will be reached is debatable. PG&E states that participation has grown to over 75,000 customers with the $25 incentive, and indicates that is well on its way to achieving the 25% market penetration target, but does not indicate where it is now and how much further it needs to go to meet the target.

We accept PG&E's explanations related to PCT duration and RA credits, but TURN's proposed reduction in PCT demand response due to the cost of the PCT for voluntary participants has some merit. PG&E has produced no estimate of what a PCT device would cost, while TURN estimates costs to be in the range of $90 to $120, which is significantly higher than the $25 rebate.

Given the above discussion, it is reasonable to reduce PG&E's forecasted benefits for the Title 24 PCT program by some amount. However, the state of the evidentiary record does not facilitate the quantification of what that amount should be. Demand response benefits are difficult to quantify because they depend substantially on future

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[104] In its Comments on the Proposed Decision of ALJ Fukutome, DRA noted the recent CEC Draft Committee Report on Proposed Load Management Standards, dated November 2008. In that report, the CEC proposed that communication of DR events with DR enabling technology be communicated through a Radio Data System and via the internet. In reply comments, PG&E states that in comments posted on the CEC website, PG&E and other utilities have identified major problems with the draft technical standard, and the Draft Technical Report recognizes the importance of the utilities' AMI systems that meet the CPUC's minimum functionality requirements to meeting the CEC's goals.

customer behavior to changed circumstances. Parties can speculate on what that behavior might be based on limited studies or theories but what will actually happen is far from certain. For these reasons, we will instead split the difference between TURN's estimate of Title 24 PCT program benefits and that of PG&E. We calculate that amount to be a PVRR of $83,427,000 as opposed to PG&E's estimate of $129,401,000.

11. Adopted Incremental Costs and Benefits

Table 3
Adopted Estimates of Incremental Costs

	Incremental Costs Nominal (Dollars in thousands)	PVRR
Deployment Costs		
Meter Devices (Less HAN and Electromechanical Meter Upgrades)	$ 310,757	$ 486,358
HAN Retrofit	26,532	24,581
Electromechanical Meter Retrofit	18,800	20,372
Information Technology	33,600	49,793
Title 24 Program Costs	-	26,174
Peak Time Rebate Program Costs	-	27,592
Project Management	-	-
Training	1,697	1,592
Risk Based Allowance	44,139	46,724
Subtotal	$ 435,525	$ 683,186
Operations and Maintenance Costs		
Operations and Maintenance	$ 4,993	$ 42,886
Risk Based Allowance	562	503
Subtotal	$ 5,555	$ 43,389
Other Costs		
Technology Assessment	$ 21,400	$ 18,995
Risk Based Allowance	4,280	3,445
Subtotal	$ 25,680	$ 22,440
Total Incremental Costs	$ 466,760	$ 749,015

Table 4
Adopted Estimates of Incremental Benefits

	Incremental Benefits Annualized (Dollars in thousands)	PVRR
Operational Benefits		
Integrated Connect/Disconnect Switches		
Avoided Field Visits	$ (6,682)	$ (114,702)
Improved Cash Flow	(969)	(11,174)
Reduced Bad Debt	(2,429)	(26,756)
Tax Benefit from Meter Replacement	n/a	(11,799)
Subtotal	$ (10,080)	$ (164,431)
Energy Conservation/Demand Response Benefits		
Electric Conservation	n/a	$ (268,847)
Gas Conservation	n/a	0
Peak Time Rebate	n/a	(262,916)
A/C Cycling	n/a	(83,427)
Subtotal	n/a	$ (615,190)
Total Benefits	n/a	$ (779,621)

11.1. Conclusion

The adopted costs and benefits result in a PVRR net benefit of $(30,606,000). By this adopted analysis, the Upgrade is cost effective. However, we note that, when compared to the total Upgrade incremental PVRR cost of $749,015,000, that net benefit is small (only 4.1%). It is insignificant when considering the uncertainties in estimating the PVRR of the Upgrade costs and benefits, especially the conservation and demand response benefits. Changes in only a few assumptions could make the Upgrade cost ineffective or substantially more cost effective. Despite the narrow margin of cost effectiveness reflected in this decision, we feel it is reasonable to authorize PG&E to proceed with the proposed SmartMeter Upgrade, subject to the conditions and costs specified in this decision and will do so. Our judgment is influenced by the results of the cost effectiveness analysis and following additional factors:

- In PG&E's original AMI proceeding, benefits exceeded costs by $104.4 million (4.6%). When looked at on a total basis, it is even more likely that the ratepayers will not be harmed by implementing the Upgrade.

- As described previously by PG&E, on a total basis, the SmartMeter Program compares favorably with what was authorized for SCE and SDG&E. While our adjustments to PG&E's estimates may make that comparison less favorable, it is worthwhile to note that PG&E's costs and cost effectiveness are still in the range of the other two IOUs.

- Authorizing the Upgrade results in a common statewide technology platform for the three IOUs. In general, reasonable consistencies in system components and functionality will facilitate the implementation of consistent demand response and conservation programs, which is desirable.

- The upgraded technology will provide for a technology platform that offers common functionality for PG&E customers, for utility program offerings, and for vendor development of tools, applications, and the expanding market for home energy management devices. Consistency in the marketplace will provide vendors a common set of functionality against which to develop interoperable products that adhere to common standards.

- It is likely that there are other benefits that have not been quantified by PG&E or other benefits that can be realized through the upgrade technology that may arise in the future.

12. Cost Recovery

12.1. General Proposal

Regarding cost recovery of the Upgrade, PG&E proposes the following ratemaking treatment:

- Rates will be set initially to recover forecasted project costs, including the incremental costs and benefits of the SmartMeter Program Upgrade; with true-up to actual costs achieved through the existing SmartMeter Balancing Account – Electric (SBA-E).

- The Commission will review forecasted incremental costs in this application and, as a result of that review, these forecasted costs will be deemed reasonable and will not be subject to after-the-fact reasonableness review. If actual costs exceed the forecast, then PG&E proposes to file for recovery of the difference through a traditional after-the-fact reasonableness review filing.

- Costs associated with the SmartMeter Program Upgrade incurred prior to a Commission decision of this application and recorded in a memorandum account, upon approval of the advice letter filed concurrently with this application, will also be reviewed in this application, and as a result of that review, these incurred costs will be deemed reasonable and will be transferred to the SBA-E for recovery.

- Incremental benefits or cost reductions will also be reviewed in this proceeding, and specified pre-approved forecasted benefits will be incorporated into rates through the SBA-E as associated project milestones are met.

- Rates covering the SmartMeter Program Upgrade, including the incremental costs and benefits, will be revised annually in the Annual Electric True-Up advice letter, or as otherwise authorized by the Commission.

As ordered in D.06-07-027,[105] PG&E indicates that it will present testimony in its next GRC concerning the continuation of the balancing accounts as an alternative to traditional ratemaking treatment.

No party has challenged PG&E's general cost recovery proposal as described above. It is reasonable and will be adopted. However, parties have challenged certain aspects of PG&E's allocation methodology, as well as the benefits recognition proposal, as discussed below.

12.2. Generation/Distribution Allocation

PG&E proposes to recover the SmartMeter Program Upgrade costs from customers in the same manner as adopted in D.06-07-027 for other SmartMeter Program costs. That is, the total revenue requirement will be recovered in the same manner as other distribution revenue, based on the distribution revenue allocation and rate design methods authorized by the Commission at that time.

12.2.1. DRA's Position

Since PG&E justifies the Upgrade costs primarily on demand response and energy conservation benefits, DRA recommends that any Upgrade costs approved by the Commission be allocated by a generation allocator. According to DRA, savings due to peak load reduction and energy conservation typically flow through an energy resource recovery account, from which the account balance automatically flows to customer classes based on a generation allocator. This means that, if the potential benefits of the Upgrade do occur, the energy saving benefits would flow back to customer classes accordingly. For the residential class, the generation allocator is approximately 40.6%. DRA argues that, as the residential class would obtain 40.6% of potential benefits, it makes sense that they also pay 40.6% of the costs. According to DRA, PG&E's proposal to allocate AMI Upgrade costs by a distribution allocator would allocate 55.1% of these

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[105] D.06-07-027, Ordering Paragraph 15.

costs to the residential class. DRA states that PG&E is thus recommending that residential customers pay far more than they would potentially benefit from the Upgrade. DRA instead recommends that the Commission allocate any approved Upgrade costs by generation allocators that would allocate approximately 40.6% of these costs to the residential class.

In response, PG&E states that DRA's proposal is inconsistent with established practices of cost allocation. PG&E notes that DRA acknowledges PG&E's proposal follows the method already being used to recover those costs authorized by PG&E's Original AMI Case. PG&E also notes that its proposal is consistent with the method adopted by the Commission in SDG&E's recent AMI case, as well as DRA's settlement with SCE on its recent AMI case.[106] Furthermore, PG&E is not aware of any cases where distribution infrastructure costs have been allocated on a method other than to distribution-level EPMC.

12.2.2. Discussion

At this point, we will continue the use of the allocation methodology that applies to PG&E's original AMI authorization. In general, it is reasonable to allocate distribution infrastructure with distribution level EPMC related allocators, and PG&E's methodology is consistent with how SDG&E's AMI related costs are allocated. We will not preclude DRA, or any other party, from raising the issue in PG&E's next Phase 2 GRC proceeding. In fact, that would be a more appropriate forum for proposing such an allocation methodology that is based on principles which differ significantly from existing principles.[107]

[106] The SCE AMI settlement defers consideration of the allocation methodology to SCE's GRC, and uses a distribution allocation for any interim period.

[107] In this proceeding, the record on this issue is limited. Viewing it in the context of all of PG&E costs would provide a venue for considering all costs and applying the proposed principles in a consistent manner across all costs, if adopted.

12.3. Streetlight Allocation

CAL-SLA argues that PG&E does not need a meter to determine street light energy usage.[108] According to CAL-SLA, PG&E already has more than sufficient information to determine annual energy usage from streetlights, so a meter would be surplus. CAL-SLA also notes that while some other customers might use the SmartMeter to alter their energy usage pattern, it is not the case with street lights, since they only operate at night.

CAL-SLA's policy position is, since SmartMeters will not be installed on street lights because they are unnecessary, street light customers should not pay for SmartMeters. CAL-SLA points out that it has never contended that street light facility charges which are unique to street lights should be assessed against all other customers.

PG&E disagrees with CAL-SLA's position for the following two reasons. First, it is at odds with the Phase 2 GRC Settlement, of which CAL-SLA was a signatory. Second, CAL-SLA's position ignores the benefits that would accrue to streetlights customers from the Upgrade. According to PG&E, street light customers will receive benefits as a result of many of the improved operating efficiencies that will benefit all customer classes, such as reduced labor costs and improved cash flows. PG&E also notes that street light customers will benefit from the new peak load management efforts and energy conservation efforts that should result in lower overall generation and distribution revenue requirements.

12.4. Discussion

In addressing this issue, we agree in general with PG&E's position that, while street light customers will not receive any benefits directly associated with having an upgraded meter, there are likely to be some benefits to street light customers due to the

[108] According to CAL-SLA, out of the approximate 45,000 streetlight accounts taking service from PG&E, 1,000 are metered under Schedule LSD-3.

Upgrade, in the form of increased operational efficiencies and reduced revenue requirements. For this reason, it is reasonable to allocate some amount of the Upgrade costs to street light customers. We also feel it is reasonable to use the settlement in PG&E's last rate design settlement to do so.

In its testimony, CAL-SLA states the following:[109]

> PG&E states that in Exhibit C, Table 1, the revenue allocation methodology is to allocate distribution revenue to each class based on each class' total share of present distribution revenue. For the street light class, revenue from facilities charges is included in distribution revenue used for the basis of the allocation. The inclusion of facilities charges causes the percentage increase for the street light class to be higher than for other classes and the systemwide percentage change.
>
> PG&E goes on to state that the revenue allocation methodology used in the SMU application is not what was approved in D.07-09-004 in Phase 2 of the utility's 2007 Test Year General Rate Case.
>
> CAL-SLA recommends that the Commission use the revenue allocation methodology adopted in the Phase 2 GRC D.07-09-004. Street light facilities charges should be treated as non-allocated revenues and therefore excluded from revenue allocation. Under the Phase 2 revenue allocation, street light's increase would be reduced from 1.7% to 0.5%.

The use of the Phase 2 GRC decision revenue allocation methodology for allocating the Upgrade revenue increase is apparently a secondary recommendation of CAL-SLA, whereby the street light customers' increase would be reduced when compared to PG&E's proposal for the Upgrade. In rebuttal testimony, PG&E states, "Yes. PG&E agrees that D.07-09-004, as issued in Phase 2 of PG&E's 2007 GRC, sets forth the appropriate methods for changing rates that may result from a change in revenue requirements to recover the costs of the Upgrade project."[110]

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[109] Exhibit 301, p. 8.

[110] Exhibit 8, p. 5-3.

There were a number of settlements in Phase 2 of PG&E's 2007 GRC, which addressed marginal costs, revenue allocation and rate design. In the particular settlement on marginal costs and revenue allocation,[111] Section VII.3 addresses rate changes between GRCs. The Upgrade will result in a rate change between GRCs, so it is appropriate that the Section VII.3 principles in the marginal cost and revenue allocation settlement should be followed in determining the allocation of Upgrade costs to the various customer classes. PG&E should allocate the Upgrade revenue increases accordingly.

CAL-SLA indicates that its primary recommendation does not comport with the Phase 2 GRC settlement but adds that SmartMeters were never identified in that proceeding as a cost to be allocated to street lights.

We do not know what was assumed by the settling parties, including CAL-SLA, when the marginal cost and revenue allocation settlement agreement was reached. Settlements generally represent a compromise among the Settling Parties' respective litigation positions, in order to agree on a mutually acceptable outcome. What may not seem to be fair, when viewing a portion of the settlement in isolation, may be fair, when viewing the settlement in its entirety. We can only judge issues such as this by the plain language of the settlement. Authorization of the Upgrade necessitates a rate change between GRCs. The settlement provides principles for rate changes between GRCs. There is nothing in that section of the settlement that limits the application of those principles, if the increase is driven by SmartMeter costs or any other specific costs. There is nothing that states that certain customers can avoid an increase, if the reason for that increase does not directly benefit those customers. In order to honor the settlement process, we have no alternative but to impose the principles for rate changes between GRCs, as identified in PG&E's TY 2007 Phase 2 marginal cost and revenue allocation

[111] *See* D.07-09-004, Appendix B.

settlement, in allocating the Upgrade related revenues to customer classes. In doing so, street light customers will receive an allocation of Upgrade costs, although that allocation will be substantially lower than what was originally proposed by PG&E.

By our determination today, we are not precluding CAL-SLA or any other party from raising the issue of how SmartMeter costs should be allocated in PG&E's next Phase 2 GRC proceeding. We expect such an issue would necessitate a fairly comprehensive analysis of what types of costs, beyond just SmartMeter costs, directly benefit or do not directly benefit the various customer classes and which of those costs should be assigned to particular customer classes.

12.5. Benefits Recognition

PG&E proposes to continue the current mechanism for recognizing benefits resulting from the Upgrade on a monthly basis as meters are activated and project milestones are achieved. Specifically, once the remote connect/disconnect functionality has been activated (expected in the latter half of 2009), PG&E would adjust the existing per electric meter monthly benefits calculation from $1.7722 per active electric meter per month by an additional $0.1821 per active electric meter per month, to be in effect through the end of 2010. Starting with 2011, these amounts would be subject to revision through PG&E's GRC or other applicable regulatory mechanisms. DRA and TURN dispute the timing of PG&E's benefits recognition proposal.

12.5.1. DRA's Proposal

DRA recommends that PG&E track and report the differences between the AMI benefits actually credited to ratepayers and those shown in PG&E's business cases, for both the original and Upgrade applications. DRA recommends that PG&E should automatically credit ratepayers with the benefits of both the original and Upgrade projects eight months after meter costs enter into the rate base. This will ensure that ratepayer benefits are not delayed due to further deployment delays. According to DRA, continuing the benefits recognition proposal adopted in the original AMI decision unfairly allocates a disproportionate share of the financial risks to ratepayers.

PG&E states that adhering to DRA's proposed timeline would reduce PG&E's incentive and flexibility to actively manage and reduce project costs. For instance, PG&E indicates that its management currently has incentives to take advantage of volume discounts for purchasing materials during a certain period of time, and for taking advantage of tax rules that can provide benefits from accelerating the purchase of items during a certain tax year. In order to take advantage of these discounts, PG&E may need to buy items in advance of what would be needed for the deployment schedule. A mandate to begin crediting customers eight months from the booking of such costs into rate base would provide a disincentive to PG&E from taking advantage of these discounts, resulting in higher project costs. PG&E indicates this would also increase the administrative burden and therefore the cost of running the project. Hence, PG&E believes that it would be prudent to adhere to the current benefits recognition method under which PG&E commences recording benefits only after the meter is activated.

12.5.2. TURN's Proposal

TURN states that PG&E's AMI pre-deployment and AMI deployment funding requests were both authorized, in large part, because the tangible operational cost savings flowing back to ratepayers were supposed to pay for approximately 90% of the project costs; and PG&E is significantly behind in crediting ratepayers with the per-meter operational benefits that were included in PG&E's originally authorized AMI program. TURN asserts that because PG&E's AMI project is so far behind schedule, for both gas and electric meter deployment, as compared to the deployment forecast authorized in D.06-07-027, only negligible operational cost savings have been credited back to ratepayers to date (less than 18% of total costs). TURN therefore recommends that PG&E be directed to credit at least $44.8 million in operational benefits back to ratepayers as part of this proceeding.

It is TURN's position that, given that so few operational benefits are being provided as planned, combined with the time value of money where costs and benefits in earlier years are weighted more heavily than in the outer years, PG&E's original 90% operational cost-effectiveness will no longer be achievable unless the Commission orders a crediting back to ratepayers.

In response, PG&E provides three reasons why it believes TURN's proposal should be rejected.

First, according to PG&E, the values used by TURN to calculate the level of expected benefits were forecast estimates and never meant to be—nor did they become—required targets set by the Commission. TURN's recommendation to, in essence, require PG&E to record benefits in accordance with such a schedule is contrary to the method adopted by the Commission in D.06-07-027. That method requires PG&E to record in the balancing accounts revenue requirement costs and agreed-upon benefits only after meters are activated, not in accordance with some prescribed schedule. The Commission stated:

> We find PG&E's proposed balancing account mechanism, with a per meter benefit credit, to be reasonable because PG&E recovers its new AMI-related costs on an actual basis and it ensures ratepayer benefits are captured as meters are activated. (D.06-07-027, p. 51.)

PG&E notes that in adopting this mechanism, the Commission expressly rejected a competing ratemaking proposal from TURN that would have levelized costs and benefits according to a prescribed schedule somewhat analogous to that proposed here by TURN. The Commission rejected TURN's proposal stating that it was not persuaded by TURN "[T]hat such a method is reasonable for either ratepayers or shareholders."[112]

Second, PG&E states that TURN's argument ignores the fact that recorded costs have also trended behind the original forecasts; and while TURN argues that benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule. PG&E argues that this "delay" in expenditures dwarfs the value of "delayed" benefits, a fact that benefits ratepayers under the ratemaking scheme adopted by D.06-07-027.

Third, PG&E states that TURN's argument ignores the fact that PG&E's current deployment schedule still reflects an overall completion timeframe of five years as per the original timeframes within the AMI case; and any "delay" in benefits or costs will be short-lived with project benefits accelerating during the later years of deployment.

12.5.3. Discussion

We see no compelling reason to change the benefit recognition procedures adopted in D.06-07-027 and will not adopt DRA's proposal. We recognize that DRA's proposal is similar to the benefit recognition procedure that was included in SCE's AMI decision. However, it is not clear from the record that, over the long term, the DRA proposal will be more beneficial to ratepayers. Consistency is important, but being consistent with the benefit recognition procedures previously found reasonable in D.06-07-020 is just as valid as being consistent with the settled procedure adopted for SCE. We have not been presented with evidence that suggests PG&E is mismanaging funds, and recognizing benefits when the meter is activated is reasonable, if only because no benefits can be realized until the meter is activated. Also, as PG&E indicates in responding to TURN, while benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule. For that reason, we do not see any harm to ratepayers by continuing the existing procedures.[113]

Also, PG&E's reasons for rejecting TURN's $44.8 million ratepayer credit proposal are persuasive, and we will not adopt that proposal.

13. Revenue Requirement

PG&E uses a results of operations model to compile all capital-related costs, operating expenses and benefits into an income statement format to estimate the additional amount of revenue needed to recover the cost of the Upgrade. PG&E has presented these forecasted revenues, or revenue requirement, for the following reasons:

ffi PG&E requests that initial rates for project deployment, to be effective January 1, 2009, be set based on the revenue requirements presented in its testimony, although ultimately PG&E proposes to recover actual costs of the project;

[112] D.06-07-027, p. 54.

[113] While rates will be set initially to recover forecasted project costs, including the incremental costs and benefits of the SmartMeter Program Upgrade; a true-up to actual costs will be achieved through the existing SmartMeter Balancing Account.

ﬃ PG&E also requests that SmartMeter Program Upgrade rates be changed on January 1 of 2010, based on the revenue requirement presented in its testimony, plus balancing account balances calculated at the time the rate change is requested;

ﬃ PG&E asks that the RO model assumptions and methods used to calculate the capital revenue requirements discussed in its testimony be approved for calculating monthly capital revenue requirements based on recorded SmartMeter Program Upgrade plant;

ﬃ To show how the incremental costs presented in Exhibit 3 translate into revenue increases; and

ﬃ To provide forecasted revenue requirements for the calculation and evaluation of rate impacts.

PG&E's cost recovery proposal seeks to recover the entire costs of the SmartMeter Program Upgrade from customers. PG&E requests that the Commission approve the use of the revenue requirements set forth in its showing to establish rates.

No party has disputed the use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade. The use of the model for this purpose is reasonable, and it should be used to calculate the Upgrade revenue requirements, using the costs adopted by our decision today.

14. DRA's Water Utility Proposal

DRA proposes that PG&E's SmartMeter Program facilitate the automated meter reading (AMR) of its customers' water usage. It is DRA's belief that AMR provides cost savings mainly associated with water meter reading and assists as a tool to promote water conservation. According to DRA, facilitating water AMR is fairly easy to do at the meter endpoints. Also, the amount of additional information involved would not significantly tax the head-end hardware and software given that water meter reads generally only occur monthly. The largest issue is that of PG&E coordinating with the billing departments of various water utilities and providing billing data in an electronic form in a timely and secure manner.

DRA accepts that water metering benefits need not be part of this proceeding, but urges the Commission to order PG&E to try to incorporate this potential benefit into its long term deployment. DRA states that PG&E should hold workshops, as SCE has agreed to do in its AMI settlement, to explore issues related to AMI for water utilities.

14.1. CCSF's Position

CCSF interprets that the purpose of DRA's testimony regarding water metering appears to have been to recommend that the Commission should explore the possibility of using of using PG&E's AMI system for water metering in a separate proceeding and does not object to the recommendation. CCSF states, to the extent feasible, water and electric utilities should be cooperating and working together in the best interests of their common customers. Because CCSF's water utility is in the process of implementing its own AMI system, CCSF states it is willing to work with PG&E to avoid system redundancy. In the event the Commission should decide to hold workshops on this issue, CCSF recommends that the Commission first notify all water utilities and urge them to participate.

14.2. PG&E's Position

Consistent with DRA's recommendation, PG&E supports ongoing dialogue with water agencies and seeks the flexibility from the Commission to pursue these discussions through either multi-party workshops or direct dialogue with the water utilities. PG&E also states that, for the most part, CCSF echoes the recommendations of DRA and, to the extent CCSF does so, PG&E does not disagree with CCSF's testimony. However, PG&E states that it does disagree with the suggestion in CCSF's testimony that it may be cost-effective for PG&E to consider use of CCSF's possible automated water meter reading system.

PG&E indicates that it is highly unlikely that it would ever be cost-effective for PG&E to use a water utility's water meter reading system and cites the following cross-examination of DRA's witness:[114]

> CCSF Counsel: And are they -- the AMI systems being installed by these water companies, could they be used by PG&E instead of the water companies using PG&E's?
>
> DRA Witness Abbott: No. It would normally be the other way around. And the reason for that is that the electric metering application is very data-intensive. There's an awful lot of data processing. In this case we're talking about PG&E doing hourly metering. There's very few cases that I'm aware of in which any water utility would try to deal with hourly water metering at the residential level.

PG&E agrees with DRA on this and recommends that the Commission should not entertain CCSF's suggestion any further.

14.3. Discussion

DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory is reasonable and may result in additional benefits for the SmartMeter project. PG&E and CCSF support DRA on this, and we will order PG&E to work with the water utilities, either through multi-party workshops or direct dialogue with the water utilities.[115] We suggest that this should be done sooner rather than later and will require that PG&E report back on the status of its efforts and results of its discussions on a quarterly basis.

We understand PG&E's concerns regarding its use of a water utility's AMI system and suspect that it would be an unlikely occurrence, but we will not limit potential discussion and foreclose that possibility.

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[114] DRA, Abbott, 4 RT 495-496.

[115] PG&E should arrange and conduct the workshops similar to what is currently being done by SCE in addressing a similar requirement.

15. Procurement Diversity

PG&E's SmartMeter Program, including the Upgrade approved herein, is a substantial project that will involve significant procurement of goods and services. Accordingly, we remind PG&E that "it is the declared policy of the state to aid the interests of women, minority, and disabled veteran business enterprises in order to preserve reasonable and just prices and a free competitive enterprise, to ensure that a fair proportion of the total purchases and contracts or subcontracts for commodities, supplies, technology, property, and services for regulated public utilities are awarded to women, minority, and disabled veteran business enterprises, and to maintain and strengthen the overall economy of the state."[116] Furthermore, General Order 156 requires certain utilities, including PG&E, "to submit annual detailed and verifiable plans for increasing women, minority and disabled veteran business enterprises' (WMDVBE) procurement in all categories."[117] We expect PG&E to comply with the spirit as well as the letter of General Order 156 in the course of carrying out the activities related to the Upgrade approved herein.

16. DRA Motion to Reopen the Record

On February 17, 2009, DRA filed a motion to set aside submission and reopen the record for the taking of additional evidence in this proceeding. DRA requests that Attachment A to a February 10, 2009 PG&E Ex Parte Notice (Attachment A) be introduced into the record as an indication that substantially fewer meters, when compared to the 288,000 meters forecasted by PG&E in this proceeding, were actually deployed before HAN gateway devices became available to PG&E. Once this document

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116 Public Utilities Code Section 8281(a)

117 General Order 156, "Rules Governing the Development of Programs to Increase Participation of Women, Minority and Disabled Veteran Business Enterprises in Procurement of Contracts from Utilities as Required by Public Utilities Code Sections 8281-8286", current as of August 24, 2006, Rule 1.1.1.

is entered into the record, DRA requests that, if the Commission decides against DRA to fund the retrofit, funding should be limited to the cost of retrofitting the actual number of meters that were installed in 2008 rather than PG&E's forecasted numbers.

On February 18, 2009, PG&E responded to DRA's motion. PG&E indicates its opposition, arguing that DRA has not satisfied its burden in justifying its request[118] and DRA's interpretation of the data in the Ex Parte Notice is fundamentally flawed. PG&E states that the final decision is already two months delayed beyond the schedule originally adopted for this case, and PG&E is at risk for Upgrade costs already incurred. If the record is reopened and the matter delayed, PG&E states that its costs and financial risk would be proportionately higher. PG&E also asserts that DRA's evaluation of the information contained in Attachment A contains errors and fails the high standard imposed by the Commission for reopening the record. According to PG&E, DRA misrepresents the number of meters that will require a HAN retrofit, and PG&E will actually end up spending more than its forecasted amount of $32 million to maintain the benefit stream for customers. To the extent that DRA seeks an opportunity to reduce costs based on its interpretation of actual deployment data, PG&E argues that it should have an equal opportunity to correct DRA's arguments and provide evidence that shows actual deployment costs are higher than forecasted.

16.1. Discussion

DRA's motion to set aside submission and reopen the record for the taking of additional evidence in this proceeding is denied, as explained below

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[118] According to PG&E, in a case addressing a request to reopen a proceeding under Public Utilities Code Section 1708, the Commission explained:

"The burden of demonstrating that reopening is justified is substantial. The showing required in any given case will necessarily depend on an assessment of the financial and other costs to the parties and the ratepayers should authority be suspended and a case reopened, as well as an evaluation of the information submitted in support of the request." (Re Pacific Gas and Electric Co., 4 CPUC2d 139, 150 (1980).)

That the deployment of electric and gas meters might vary, not only from what was originally planned but from updated deployment plans as time goes by, is not unexpected. The manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of factors such as the availability of materials and equipment, the regulatory process, and changes in technology as the deployment of meters is progressing. We must authorize a reasonable projected meter deployment cost based on information known and analysis conducted at a certain point in time. From that point on, we expect PG&E to manage its plans and costs in a manner that results in successful implementation of the Upgrade at or near the authorized funding levels while maximizing ratepayer value.

DRA's Motion to Reopen the Record raises the issue of determining the appropriate point in time to cut off the use of more recent information and related analyses in deciding what costs to authorize for the Upgrade. Normally that cut off point would be when prepared testimony and rebuttal testimony have been issued. That evidence can be tested through the evidentiary hearing process and critiqued in post hearing briefs.[119] While under certain circumstances, it may well be appropriate to reopen the evidentiary record to consider more recent information and changed circumstances, this is not the case with respect to the more recent information contained in Attachment A.

As indicated by DRA, Exhibit 2 in Attachment A shows that during the second half of 2008 there was a significant reduction in the deployment of meters that will require a HAN retrofit when compared to the 288,000 such meters that were forecasted to be deployed during that timeframe in PG&E's May 14, 2008 testimony. However, there is additional information in Exhibit 2 in Attachment A that indicates, among other things, that (1) the total number of gas and electric meters that were actually deployed by the end of 2008 was greater than the total number of gas and electric meters forecasted to be deployed by the end of 2008 in PG&E's testimony; (2) the related benefits for the 2008 through 2010 time period were now forecasted to be larger based on the actual deployment, as opposed to the magnitude of benefits reflected in PG&E's testimony for that timeframe; and (3) the cost to maintain the benefit stream associated with the actual deployment of meters through February 10, 2009 is expected to be greater than the $32,032,000 in HAN retrofit costs reflected in PG&E's testimony.

It appears that PG&E has modified its meter deployment plan in response to changed circumstances. As explained above, such changes can be expected and may be reasonable. In this instance, it appears that there is a slight increase in benefits with the change. It also appears that the costs related to the changed plan, which includes costs to retrofit a reduced number of meters with HAN gateway devices and costs to accelerate the meter deployment schedule, among other things, will exceed the forecasted amount for the HAN retrofit that was contained in PG&E's testimony. That is, while the number of meters requiring a HAN retrofit has decreased, the revised deployment plan that reflects that reduction will actually cost more than the originally forecasted HAN retrofit.

At this point, we do not feel it is necessary to reopen the record for the taking of additional evidence. While there may be an indication that costs are being incurred in a different manner than anticipated in the process of deciding this matter, that indication in itself is not sufficient reason to reopen the record for this proceeding. For a project of this magnitude, we do not expect that any amount of evidence record will result in a forecast of costs that will be replicated by what is actually spent on a detailed cost category basis. As mentioned previously, the manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of changed circumstances. Also, when looked at in total, the Attachment A information does not

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[119] In certain instances, such as in GRCs, update testimony and associated evidentiary hearings

Footnote continued on next page

support a significant cost decrease as requested by DRA. It, in fact, shows overall increased costs. However, if total projects costs were to go up as indicated in Attachment A, it would be appropriate to assume that the additional costs would be covered by the risk based allowance authorized by this decision. Under these circumstances, it would not be an efficient use of Commission resources to reopen the record to consider all aspects of the information contained in Attachment A, a process that might require additional evidentiary hearing and briefs.

17. Comments on Proposed Decision

The proposed decision of the ALJ 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 January 16, 2009 by PG&E, DRA, TURN, CCSF and CAL-SLA. Reply comments were filed on January 22, 2009 by PG&E, DRA, and TURN

To the extent that comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, technical, and legal errors have been considered, and, if appropriate, changes have been made.

17. Assignment of Proceeding

Rachelle B. Chong is the assigned Commissioner and David K. Fukutome is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Commission has already authorized deployment of the HAN gateway for both SDG&E and SCE, and to do for PG&E would ensure statewide consistency as long as their efforts are coordinated. Consistency is important in providing a basis on which the

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are provided for.

HAN technology can efficiently develop and for providing a large market force that can be influential in developing appropriate standards.

2. There is no evidentiary record on which to judge the merits of a stand-alone HAN gateway device.

3. The most cost effective way to provide HAN access through PG&E's meters, over the long term, would be through PG&E's meter deployment plan rather than through random retrofits.

4. The increased functionality of the integrated load limiting connect/disconnect switch could be used to implement certain demand response programs and to provide area-wide and system-wide relief during peak usage periods that are in the public interest and are not available under PG&E's original AMI program.

5. The integrated load limiting connect/disconnect switch provides significant incremental operational benefits related to field technician labor savings for connect/disconnect services.

6. 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, and potentially more features in the future, are possible because of the increased processing power, memory storage, programmability, and upgradeability provided by the solid state meter platform.

7. No party disputes the technological merits of the advanced solid state meter.

8. PG&E is not requesting additional funds for either its electric or gas communication networks.

9. Certain technologies, such as that related to communication networks, have evolved over the course of PG&E's SmartMeter project making them more cost effective to employ.

10. PG&E considers any costs and benefits related to its total AMI project (original plus Upgrade) that were not specifically included in the original AMI project cost/benefit

analysis to be incremental for the purposes of justifying the cost effectiveness of the Upgrade.

11. DRA believes that Upgrade benefits that could have been achieved by the original AMI system that was approved by the Commission in D.06-07-027, should be excluded from the cost-effectiveness analysis for the Upgrade. TURN and CCSF support DRA's position.

12. The levels of conservation and demand response benefits PG&E claims in the Upgrade cannot be achieved without the further expenditures contained in the Upgrade.

13. DRA's definition of incremental is unduly restrictive in that it results in certain benefits not being recognized at all for cost effective purposes, either in PG&E's original AMI case or the Upgrade.

14. DRA's definition of incremental is essentially at odds with the manner in which the Commission evaluated the AMI requests of SDG&E and SCE.

15. The record in this proceeding is insufficient for determining the cost effectiveness of PG&E's SmartMeter program on a total basis (PG&E's original AMI plus the Upgrade).

16. The Upgrade will facilitate upgrades of both firmware and software and will enable PG&E to update both the functioning of the endpoint and initiate future programs without the necessity of visiting the endpoint. This aspect of the Upgrade should permit the current technology to perform capably well into the future even in the face of major advancements in technology.

17. PG&E's estimate of meter device costs is based on costs derived from an RFP process. Based on responses to that process, PG&E conducted an evaluation of the integrated meter devices from certain vendors to help identify vendor and meter device technologies best suited to serve PG&E and its customers.

18. Details regarding DRA's estimate of meter device costs is limited due to non-disclosure restrictions.

19. The HAN Retrofit involves PG&E deploying 288,000 upgraded meters with load limiting switches and upgrading these meters with HAN gateway devices at a later date.

20. The estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic impact of a deployment scenario.

21. Costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the HAN Retrofit comparative analysis, because they would be the same for all scenarios being compared.

22. PG&E's consultant's HAN retrofit suspension analysis was performed before the HAN retrofit aspect of meter deployment began, and was thus available for PG&E's project management to use in determining whether or not to go forward.

23. Despite the significant costs related to the HAN Retrofit, the evidence suggests that lost benefits, due to a meter deployment suspension until the HAN devices became available, would exceed the net reduced costs caused by the suspension.

24. PG&E has not fully supported and justified the magnitude of its HAN retrofit cost estimate.

25. Electromechanical meters have been deployed in the Kern region, and, as a result of PG&E's Upgrade request, the electromechanical meter costs will become stranded once these meters have been replaced.

26. In our analysis of PG&E's risk based allowance, we have determined that the stranded costs related to the electromechanical meters should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project.

27. The basis for DRA's proposal for a 30% use of the HomePlug or PLC technology stems from a hypothetical analysis involving cost sensitivity based on a 30% assumption. There is no evidence as to the reasonableness of using 30% to reflect what might actually occur.

28. The determination of who will use the HAN technology and to what extent they will use it is fairly subjective at this point.

29. HAN connectivity on a universal basis makes sense for such purposes as advancing and developing the HAN technology in an efficient manner.

30. It is PG&E's responsibility to achieve HAN connectivity in the most cost effective manner within the costs and risk based allowances provided by this decision.

31. In its supplemental testimony, PG&E indicates that it now expects to begin recruiting AC customers in 2013 and estimates the number of customers for that year to be 18 with increasing amounts thereafter.

32. Regarding IT costs associated with the Title 24 PCT program, PG&E has provided no specific reasons to justify why these costs need to be incurred prior to or in 2011 and why they cannot be shifted commensurate with when the expected recruitment of Title 24 PCT customers is expected to begin.

33. There is significant uncertainty as to when Title 24 PCT program will begin, and the program costs have already been moved by PG&E to 2013, outside the timeframe for cost recovery authorized by this decision.

34. The adoption of PG&E's IT proposal, as a means for addressing significant systems integration challenges, is consistent with the Commission's authorization of the same advanced metering technologies, with the same integration challenges, for SDG&E and SCE.

35. DRA and TURN have not forecasted the PVRR of any Title 24 PCT program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither Title 24 PCT program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade.

36. Reduction of Title 24 program costs related to marketing and incentive costs, commensurate with reductions to program participation, results in adopted Title 24 PCT program costs of $26,174,000 on a PVRR basis.

37. DRA and TURN recommend no PTR program costs, not because of any differences in what the estimated costs should be, but because of their positions that

neither PTR program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade.

38. PG&E requests $15.3 million in additional project management costs associated with additional project management efforts that will be required as the industry continues to evolve and offer new technologies.

39. In our analysis of PG&E's risk based allowance, we have determined that PG&E's requested additional project management costs should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project.

40. PG&E's technology assessment cost request has not been fully justified and appears to be excessive.

41. It is not clear that the currently proposed communication networks are deficient in particular respects, and it is not clear how BPL, MPL or IP would be incorporated into the currently proposed AMI structure.

42. There is potential value in having PG&E monitor market place developments.

43. There is value in pilot testing to ensure that the proposed network can be integrated into the AMI and will work as intended.

44. While laboratory testing and product demonstrations should first be the responsibility of those in private industry who will in the end profit from the various HAN related devices, there is merit to PG&E's alternate proposal to have ratepayers fund certain technology assessment costs in conjunction with matching funds from other sources.

45. Potential problems such as security breaches, interference with bill reading and interruption of customers' service can be avoided by first testing devices in a lab that replicates PG&E's system.

46. There is value in having PG&E provide input to and obtain information from private sector projects and to interact with developers and other utilities as HAN standards are developed.

47. No party disputes PG&E's estimate of incremental training costs.

48. No party objects to the concept of a risk based allowance or contingency.

49. Analysis of risk for the Upgrade should consider the risk profiles specific to the Upgrade, rather than that of the original AMI project.

50. A review of PG&E's proposed risk factors does not cause any specific concerns with the magnitude of the factors or with the cost categories to which they are applied.

51. The types of equipment to be deployed and the number and types of vendors that will be managed during the project are elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts fort the Upgrade.

52. The electromechanical meters in Kern County, which have become stranded, were an element of PG&E's original AMI project.

53. Changed timing and scope are elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade.

54. Changed scope (i.e., advanced meters with higher functionality) is the driving factor that resulted in the electromechanical meters and associated equipment becoming obsolete.

55. For operation and maintenance, the only category of costs challenged by intervenors is that relating to expected calls to PG&E's call centers concerning the HAN device.

56. DRA recommends reducing PG&E's call center costs by 70% to reflect the fewer calls that will be received as a result of DRA's lower HAN adoption rate, despite its recommendation to reduce PG&E's HAN adoption rate by only 30%.

57. No party has challenged either PG&E's inclusion of field technician labor savings as a benefit or PG&E's quantification of these savings.

58. No party has challenged PG&E's inclusion of reduced bad debt savings as a benefit or PG&E's quantification of these savings.

59. No party has challenged PG&E's inclusion of reduced cash flow savings as a benefit or PG&E's quantification of these savings.

60. Whether the tax retirement benefit for meters is identified as a benefit or a reduction to costs, the net effect with respect to any benefit/cost analysis will be the same.

61. The need for reprogramming advanced meters is caused by the added functionality of the programmable meter itself.

62. The cost savings identified by PG&E, with respect to its remote programmability adjustment, are related to potential costs that never existed. Those costs are avoided because the meter that necessitates the costs can accomplish the task remotely.

63. Conservation benefits were not quantified in PG&E's original AMI proceeding.

64. The 1979 study by McClelland and Cook, used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage, does not provide persuasive evidence to support DRA's conclusions on this issue.

65. The shareholder risk/reward incentive mechanism for energy efficiency programs relates to energy efficiency and not conservation, and the conservation benefits for the Upgrade include both energy efficiency and conservation.

66. PG&E's estimate of 30% IHD penetration and DRA's estimate of 21% are based on new technology acceptance curves for different products (cell phones and CFLs).

67. There is sufficient evidence to determine that customers will use information obtained from IHDs to change their electricity usage patterns.

68. Both PG&E and DRA recommend that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade.

69. The IHD shows electricity usage, not gas usage.

70. The economic incentive for reducing gas usage is likely a result of a gas bill or an examination of gas rates rather than a customer looking at an IHD and noting electricity usage patterns.

71. With respect to customers that supposedly do not clearly differentiate electric and gas consumption by their appliances, there is no record evidence indicating what

proportion of the customer base that might be. Furthermore, there is no record evidence indicating whether such customers would be the type that would even purchase an IHD.

72. With respect to the PTR program design, PG&E proposes a single-tier incentive, while DRA proposes a two tier incentive.

73. A two-tier PTR incentive has been adopted for SDG&E, and a two-tier PTR incentive settlement proposal for SCE has been deferred to SCE's Phase 2 GRC proceeding.

74. Requiring PG&E to propose a two-tier PTR incentive design in its November 2009 rate design window filing, will allow PG&E time to (1) work with DRA and other parties to work out program details; (2) consider the adopted design for SDG&E along with any solutions to practical considerations, if any; and (3) monitor and evaluate what has happened or will happen in SCE's Phase 2 GRC with respect to implementing a two-tier PTR program design.

75. That SEER is not a reliable predictor of energy performance or of demand reduction in California is supported by evidence.

76. There is evidence that there are energy savings ranging from 6% to 33%, associated with upgrading from a lower SEER system to a higher SEER system under different upgrading scenarios, although the number of units achieving expected savings is low (from 8% to 29%).

77. There is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population.

78. The Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the demand models from the SPP.

79. Rejection of TURN's proposed 30% elasticity adjustment is consistent with Commission action in D.08-09-039 regarding TURN's similar proposal in SCE's AMI proceeding.

80. While PG&E demonstrates that a non-CAC customer might realize significant savings under the PTR program under certain scenarios, there is no evidence as to suggest what the expected scenario might be and what savings would result from such a scenario.

81. Regarding non-CAC customer participation in the PTR program, there will likely be a response beyond that of those who would participate for environmental or societal reasons.

82. In D.08-09-039, the Commission rejected TURN's proposed demand response guarantee for SCE, which is similar to TURN's proposed demand response guarantee for PG&E.

83. PG&E has produced evidence from which it can be concluded that its cost effectiveness analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement.

84. The Commission has no way of knowing whether or not any future CEC assumed costs would significantly affect the cost benefit analysis as it applies to the Upgrade.

85. There is no certainty that the Title 24 PCT regulations will be implemented in 2012, if ever.

86. Whether the amount of voluntary participation will grow, if the Title 24 PCT regulations are not enacted, is uncertain.

87. Regarding PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, while PG&E gives a reasonable explanation of why 0.48 KW/hour savings may be low, it provides no convincing evidence to justify its assertion that different ramping strategies will necessarily result in 0.75 kW/hour savings.

88. Regarding the SmartAC program, while PG&E states that participation has grown to over 75,000 customers with the $25 incentive, and indicates that it is well on its way to achieving the 25% market penetration target, it does not indicate where it is now and how much further it needs to go to meet the 25% target.

89. PG&E has produced no estimate of what a PCT device would cost, while TURN estimates costs to be in the range of $90 to $120, which is significantly higher than the $25 rebate.

90. No party has challenged PG&E's general cost recovery proposal.

91. In general, it is reasonable to allocate distribution infrastructure with distribution level EPMC related allocators.

92. PG&E's cost allocation methodology is consistent with how SDG&E's AMI related costs are allocated.

93. There were a number of settlements in Phase 2 of PG&E's 2007 GRC, which addressed marginal costs, revenue allocation and rate design. In the particular settlement on marginal costs and revenue allocation, Section VII.3 addresses rate changes between GRCs.

94. With respect to benefits recognition, there is no evidence that PG&E is mismanaging funds.

95. Recognizing AMI benefits when the meter is activated is reasonable, because no benefits can be realized until the meter is activated.

96. Regarding TURN's benefits recognition proposal, the Commission rejected a similar ratemaking proposal from TURN in D.06-07-027.

97. While benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule.

98. PG&E's current deployment schedule still reflects an overall completion timeframe of five years.

99. No party has disputed the use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade.

100. DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory may result in additional benefits for the SmartMeter project.

101. That the deployment of electric and gas meters might vary, not only from what was originally planned but from updated deployment plans as time goes by, is not unexpected.

102. The manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of factors such as the availability of materials and equipment, the regulatory process, and changes in technology as the deployment of meters is progressing.

Conclusions of Law

1. This is an appropriate time to authorize deployment of HAN gateway devices for PG&E, and PG&E's request to do so is reasonable.

2. PG&E should work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

3. The increased functionality and the potential uses of the integrated load limiting connect/disconnect switches justify providing all electric residential customers with such switches.

4. PG&E's decision to ubiquitously deploy the advanced solid state meter for the SmartMeter Upgrade is reasonable.

5. PG&E should provide quarterly reports on the implementation progress of the SmartMeter Upgrade to the Commission's Energy Division and any interested parties.

6. PG&E should select the communication network(s) that provide the necessary functions in the most reasonable cost-effective manner.

7. PG&E's definition of incremental for cost effectiveness analysis purposes of the Upgrade is reasonable.

8. Any future requests to upgrade the SmartMeter Program should be critically reviewed with the understanding that our interpretation of cost effectiveness in this proceeding is appropriate for the circumstances that exist today and may well be inappropriate for circumstances that exist in the future.

9. The use of a total cost effectiveness analysis should be limited to showing whether or not the cost effectiveness of PG&E's SmartMeter program is in the range or generally comparable to that of SDG&E and SCE.

10. It would be inappropriate to impose DRA's proposed meter device costs on PG&E without assurance that the related meter devices provide the necessary functions, without assurance that the vendors are capable of providing the equipment when needed, and without knowledge of the type of warranties that are associated with the costs.

11. PG&E's decision to proceed with the HAN retrofit was reasonable.

12. To account for uncertainties and attempt to ensure that ratepayers only fund appropriate costs, it is reasonable to reduce adopted funding for the HAN retrofit by $5,500,000 (plus $550,000 for the related risk based allowance).

13. For the electromechanical meter upgrade, a cost of $18.8 million for the upgraded system is reasonable.

14. PG&E's general direction in attempting to deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises is reasonable.

15. PG&E should adapt the implementation of HAN connectivity over time consistent with approaches and solutions that are being addressed and developed, currently and in the future, by those in the industry that are addressing these issues.

16. Because we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade, it is also appropriate to include the $4.0 million in IT costs related to the PTR program, in rates, as requested by PG&E.

17. IT costs associated with the Title 24 PCT program should be recovered in conjunction with PG&E's cost recovery of the Title 24 PCT program costs.

18. Because we have included the benefits of the Title 24 PCT program in evaluating the cost effectiveness of the Upgrade, it is appropriate to include the costs of Title 24 PCT program in that evaluation.

19. Since this decision approves a two-tier PTR incentive structure that will be detailed by PG&E in a November 2009 rate design window filing, it would be more appropriate to address the costs of such a program at the same time, rather than as part of this decision.

20. It is reasonable to use PG&E's estimated PVRR amount of $27,592,000 that is associated with a single tier PTR incentive structure, for the purpose of evaluating the cost effectiveness of the Upgrade in this decision.

21. Since we have adopted DRA's proposed HAN adoption rates, which were derived by applying a 0.7 scalar to PG&E's proposed adoption rates, it is reasonable to apply the same 0.7 scalar to PG&E's proposed call center costs, resulting in an adopted call center estimate of $319,000, which is $136,000 less than projected by PG&E.

22. With respect to devices that would enable home computers to function as in-home displays, technology assessment costs should be borne by those in private industry who will, in the end, profit from the device.

23. PG&E's proposed risk base allowance methodology along with the specific factors themselves and the categories of cost to which they are applied are reasonable.

24. It is reasonable that the additional project management costs requested by PG&E as part of the Upgrade should instead be covered by the risk based allowance adopted in D.06-07-027.

25. With respect to laboratory testing and product demonstrations, it is reasonable that ratepayers provide at least some of those costs related to protecting PG&E's system from such potential problems as security breaches, interference with bill reading and interruption of customers' service, which can be avoided by first testing devices in a lab that replicates PG&E's system.

26. It is reasonable to allow $6 million as the ratepayers' share of laboratory testing and product demonstration costs, with the understanding that PG&E can only use those ratepayer provided funds to the extent that it matches those funds from other sources. Any unspent funds for this particular category should be credited back to ratepayers.

27. Since the decisions to deploy the electromechanical meters in Kern County were made by PG&E in conjunction with the original AMI authorization, it is appropriate that the consequences of those decisions should be reflected as part of that same authorization.

28. It is reasonable that the stranded costs related to the electromechanical meters deployed as part of PG&E's original AMI project should be covered by the risk based allowance authorized by D.06-07-027 for the original AMI project.

29. PG&E's estimates of field technician labor savings, reduced bad debt savings, improved timing of cash flow savings, and the tax benefit from meter retirement are reasonable and should be adopted.

30. To assign the PG&E identified remote programmability benefit as an incremental benefit in the cost effectiveness analysis of the Upgrade is illogical and inappropriate.

31. Rather than reducing PG&E's estimate of electric conservation benefits by 12% as recommended by DRA, it would be appropriate, when the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, for PG&E to ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the Upgrade.

32. It is reasonable to be conservative and to adopt DRA's IHD penetration estimate of 21%, partly because of the speculative nature of the forecasts and partly due to TURN's legitimate concerns regarding the cost of the IHD devices.

33. It is reasonable that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade.

34. Since we do not feel that customers' decisions as to whether they should limit or curtail gas usage are significantly enhanced by the presence of IHDs that only display electricity usage patterns, zero gas conservation benefits should be used in the cost effectiveness analysis of the Upgrade.

35. For statewide consistency purposes, it is reasonable to impose a two tier PTR incentive design on PG&E and to require PG&E to propose such a design in its November 2009 rate design window filing.

36. Consistent with our acceptance of PG&E's definition of "incremental" for purposes of determining Upgrade costs and benefits, it is appropriate to include PTR benefits that result from PG&E's SmartMeter project and that were not quantified in PG&E's original AMI proceeding.

37. Even though the climate and other factors particular to California are not the same as that assumed for SEER purposes, it is reasonable to assume that as manufacturers attempt to make more efficient systems to comply with upgraded SEER levels, there will be some effect of demand reductions and energy savings in California.

38. It is reasonable to reduce TURN's proposed SEER adjustment by 50% to reflect increased AC efficiencies that result from increased SEER requirements.

39. Regarding non-CAC customer participation in the PTR program, it is reasonable to split the difference between the PG&E and TURN forecasts, resulting in a non-CAC customer participation rate of 35.5%.

40. For the same reasons expressed by the Commission in D.08-09-039, in rejecting TURN's proposed demand response guarantee for SCE, it is appropriate to reject TURN's proposed demand response guarantee for PG&E.

41. Similar to what was required for SCE in D.08-09-039, PG&E should report to the Commission on the energy savings and associated financial benefits of all DR, load control, energy efficiency, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers.

42. It is not appropriate to completely dismiss the use of Title 24 PCT benefits in the Upgrade cost effectiveness analysis, as proposed by both DRA and TURN.

43. Regarding Title 24 PCT benefits, it is reasonable to split the difference between the PG&E and TURN forecasts, resulting in a PVRR of $83,428,000 as opposed to PG&E's estimate of $129,401,000.

44. PG&E's general cost recovery proposal is reasonable.

45. For the Upgrade, it is reasonable to continue the use of the cost allocation methodology adopted by the Commission for PG&E in D.06-07-027.

46. Parties are not precluded from raising issues related to the allocation of SmartMeter costs in PG&E's next Phase 2 GRC proceeding.

47. In order to honor the settlement process, we have no alternative but to impose the principles for rate changes between GRCs, as identified in PG&E's TY 2007 Phase 2 marginal cost and revenue allocation settlement, in allocating the Upgrade related revenues to customer classes, including the street light class.

48. It is not necessary to change the benefits recognition procedures as proposed by DRA.

49. PG&E's reasons for rejecting TURN's $44.8 million ratepayer credit proposal are persuasive.

50. The use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade is reasonable.

51. PG&E's results of operations model should be used to calculate the Upgrade revenue requirements using the costs adopted by our decision today.

52. DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory is reasonable.

53. In order to pursue AMR for water meters, PG&E should work with the water utilities in its service territory, either through multi-party workshops or direct dialogue and report back to the Commission on a quarterly basis until completed.

54. It would not be an efficient use of Commission resources to reopen the record to consider all aspects of the information contained in the Attachment A, a process that might require additional evidentiary hearing and briefs.

55. DRA's Motion to Reopen the Record should be denied.

ORDER

IT IS ORDERED that:

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.

3. PG&E shall file an advice letter no later than 30 days from the effective date of this decision, to implement rates for 2009 to cover the costs of the SmartMeter Upgrade.

4. PG&E shall use its results of operations model incorporating the costs adopted in this decision to determine the appropriate revenue requirements for the SmartMeter Upgrade project. Detailed results shall be included in PG&E's advice letter that implements rates for the SmartMeter Upgrade.

5. PG&E shall work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

6. In its next general rate case (GRC) for test year 2011, PG&E shall make an affirmative showing that it has avoided double recovery of any authorized SmartMeter Upgrade costs, and that any requested costs in its 2011 GRC are consistent with the limits of recovery adopted in this decision.

7. PG&E shall provide quarterly reports on the implementation progress of the SmartMeter Upgrade to the Commission's Energy Division and any interested parties. PG&E shall consult with the Energy Division to determine what information to provide and to coordinate reporting requirements ordered in Decision 06-07-027.

8. When the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, PG&E shall ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the SmartMeter Upgrade.

9. A two-tier peak time rebate incentive design is adopted for PG&E. PG&E shall present a proposal to implement such a design in its November 2009 rate design window filing. The proposed rate design shall be consistent with the rate design guidance in D.08-07-045.

10. Similar to what was required for Southern California Edison Company in Decision 08-09-039, PG&E shall report to the Commission on the energy savings and associated financial benefits of all demand response, load control, energy efficiency, and conservation programs enabled by advanced metering infrastructure, including programmable communicating thermostat programs, Peak Time Rebate programs, and other dynamic rates for residential customers. PG&E shall file annual reports in April of each year until 2019. PG&E shall work with Energy Division to develop a reporting format for this information, and to determine where the reports should be filed. PG&E may request recovery for the incremental costs of this reporting requirement in appropriate cases.

11. In order to pursue automated meter reading for water meters, PG&E shall work with the water utilities in its service territory, either through multi-party workshops or direct dialogue. PG&E shall report back to the Commission on the status of its efforts and results of its discussions on a quarterly basis, beginning April 11, 2009, until completed.

12. The Division of Ratepayer Advocates Motion to Reopen the Record, filed February 17, 2009, is denied.

13. Application 07-12-009 is closed.

This order is effective today.

Dated March 12, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

APPENDIX A

************** SERVICE LIST *************

Last Updated on 22-DEC-2008 by: RC4

A0712009 LIST

**************** PARTIES ****************

Paul Angelopulo
Legal Division
RM. 5031
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-4742
pfa@cpuc.ca.gov
For: Division of Ratepayer's Advocates

William Sanders
CITY AND COUNTY OF SAN FRANCISCO
CITY HALL, RM. 234
1 DR. CARLTON B. GOODLETT PLACE
SAN FRANCISCO CA 94102
(415) 554-6771
william.sanders@sfgov.org
For: City and County of San Francisco

David J. Byers
MCCRACKEN & BYERS, LLP
1920 LESLIE STREET
SAN MATEO CA 94403-1325
(650) 377-4890
dbyers@landuselaw.com
For: California City-county Street Light Association

Brian K. Cherry
PACIFIC GAS & ELECTRIC COMPANY
PO BOX 770000, MAIL CODE: B10C
77 BEALE STREET, 1093
SAN FRANCISCO CA 94177
(415) 973-4977
bkc7@pge.com
For: Pacific Gas & Electric Co.

J. Michael Reidenbach
Law Department
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442, MAIL CODE B30A
SAN FRANCISCO CA 94120
(415) 973-2491
jmrb@pge.com
For: Pacific Gas and Electric Co.

Aloke Gupta

Nina Suetake
Attorney At Law
THE UTILITY REFORM NETWORK
711 VAN NESS AVE., STE. 350
SAN FRANCISCO CA 94102
(415) 929-8876 X308
nsuetake@turn.org
For: THE UTILITY REFORM NETWORK

************ STATE EMPLOYEE *************

Christopher J. Blunt
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1779
cjb@cpuc.ca.gov
For: DRA

Andrew Campbell
Executive Division
RM. 5203
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2501
agc@cpuc.ca.gov

Matthew Deal
Executive Division
RM. 5215
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2576
mjd@cpuc.ca.gov

David K. Fukutome
Administrative Law Judge Division
RM. 5042
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2403
dkf@cpuc.ca.gov

Theodore H Geilen
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1235
u19@cpuc.ca.gov
For: DRA

Ben Boyd

APPENDIX A

**************** SERVICE LIST ****************

Last Updated on 22-DEC-2008 by: RC4

A0712009 LIST

Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5239
ag2@cpuc.ca.gov

Bruce Kaneshiro
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1187
bsk@cpuc.ca.gov

Scarlett Liang-Uejio
Energy Division
AREA 4-A
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1851
scl@cpuc.ca.gov

Thomas Roberts
Division of Ratepayer Advocates
RM. 4104
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-5278
tcr@cpuc.ca.gov

Rebecca Tsai-Wei Lee
Division of Ratepayer Advocates
RM. 4209
505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-2140
wtr@cpuc.ca.gov
For: DRA

********* **INFORMATION ONLY** **********

Reed V. Schmidt
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVENUE
BERKELEY CA 94703-2714
(510) 653-3399 X111
rschmidt@bartlewells.com
For: California City-County Street Light Association

Roger Levy
LEVY AND ASSOCIATES
2805 HUNTINGTON ROAD
SACRAMENTO CA 95864

3001 RIVER TOWNE WAY
KNOXVILLE TN 37920
(865) 694-8884
bboyd@aclaratech.com

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST., SUITE 303
SAN FRANCISCO CA 94117
(415) 963-4439
cem@newsdata.com

Dennis J. Herrera, City Attorney
CITY AND COUNTY OF SAN FRANCISCO
CITY HALL, ROOM 234
SAN FRANCISCO CA 94102
(415) 554-4637
For: Intervenors, City & County of S.F.

Christopher Danforth
Division of Ratepayer Advocates
RM. 4209, 505 VAN NESS AVE
San Francisco CA 94102 3298
(415) 703-1481
ctd@cpuc.ca.gov
For: DRA

Shalini Mahajan, Producers
ELECTRIC UTILITIES & INDEPENDENT POWER
1285 AVE. OF THE AMERICAS
NEW YORK NY 10019
(212) 713-2491
shalini.mahajan@ubs.com

Chris King
Chief Strategy Officer
EMETER STRATEGIC CONSULTING
2215 BIDGEPOINTE PARKWAY, STE 300
SAN MATEO CA 94404
(650) 227-7728
chris@emeter.com
For: eMeter

Jeff Francetic
Business Development Manager
LANDIS+GYR, INC.
14891 LAGO DRIVE
RANCHO MURIETA CA 95683
(916) 354-8400
jeff.francetic@landisgyr.com

Larry Nixon
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MC B10A
SAN FRANCISCO CA 94105

APPENDIX A

**************** SERVICE LIST ***************

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A0712009 LIST

(916) 487-0227
rogerl47@aol.com

MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND CA 94612
(510) 834-1999
mrw@mrwassoc.com
For: MRW & Associates

Julie Dumoulin-Smith
Associate Analyst
NATURAL GAS & ELECTRIC UTILITIES GROUP
1285 AVE. OF THE AMERICAS
NEW YORK NY 10019
(212) 713-9848
julien.dumoulin-smith@ubs.com

Benjamin Schuman
PACIFIC CREST SECURITIES
111 SW 5TH AVE, 42ND FLR
PORTLAND OR 97204
(503) 727-0627
bschuman@pacific-crest.com

Case Coordination
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000; MC B9A
SAN FRANCISCO CA 94177
(415) 973-4744
regrelcpuccases@pge.com

Christopher J. Warner
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B10A
SAN FRANCISCO CA 94120
(415) 973-2069
cjw5@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Dionne Adams
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., MAIL CODE B10A
SAN FRANCISCO CA 94105
(415) 973-6157
DNG6@pge.com

Theresa L. Mueller
Chief Energy & Telecommunications Deputy
SAN FRANCISCO CITY ATTORNEY
CITY HALL, ROOM 234
SAN FRANCISCO CA 94102-4682
(415) 554-4640
theresa.mueller@sfgov.org

(415) 973-5450
lrn3@pge.com

Ronald Helgens
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., MC B10A
SAN FRANCISCO CA 94105
(415) 973-7524
rrh3@pge.com

Shirley A. Woo
Law Department
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO CA 94120
(415) 973-2248
saw0@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Steven W. Frank
Law Department
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B30A
SAN FRANCISCO CA 94177
(415) 973-6976
SWF5@pge.com
For: PACIFIC GAS AND ELECTRIC COMPANY

Rasha Prince
Regulatory Case Mgr
SAN DIEGO GAS & ELECTRIC CO
555 WEST 5TH STREET, GT14D6
LOS ANGELES CA 90013
(213) 244-5141
rprince@semprautilities.com

Carol Manson
Regulatory Affairs
SAN DIEGO GAS & ELECTRIC CO.
8330 CENTURY PARK COURT CP32D
SAN DIEGO CA 92123-1530
(858) 650-4119
cmanson@semprautilities.com
For: SAN DIEGO GAS & ELECTRIC CO.

Patrick J. Forkin Iii, Cpa
Senior Equity Research Analyst
TEJAS SECURITIES GROUP, INC.
7700 BONHOMME AVE., SUITE 575
CLAYTON MO 63105
(314) 862-2437
Pforkin@tejassec.com

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************** SERVICE LIST **************

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A0712009 LIST

Sandra Rovetti
Regulatory Affairs Manager
SAN FRANCISCO PUC
1155 MARKET STREET, 4TH FLOOR
SAN FRANCISCO CA 94103
(415) 554-3179
srovetti@sfwater.org

Theresa Burke
Regulatory Affairs Analyst
SAN FRANCISCO PUC
1155 MARKET STREET, 4TH FLOOR
SAN FRANCISO CA 94103
(415) 554-1567
tburke@sfwater.org

Eric P. Dresselhuys
SILVER SPRING NETWORKS
575 BROADWAY STREET
REDWOOD CITY CA 94063
(414) 899-3663
ericd@silverspringnet.com

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
LAW DEPARTMENT, ROOM 370
2244 WALNUT GROVE AVENUE, ROOM 370
ROSEMEAD CA 91770
(626) 302-4875
case.admin@sce.com
For: SOUTHERN CALFORNIA EDISON COMPANY

Janet S. Combs
SOUTHERN CALIFORNIA EDISON COMPANY
PO BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-1524
janet.combs@sce.com
For: SOUTHERN CALIFORNIA EDISON COMPANY

Adar Zango
Analyst
ZIMMER LUCAS PARTNERS
535 MADISON - 6TH FLOOR
NEW YORK NY 10022
(212) 440-0749
zango@zimmerlucas.com
For: ZIMMER LUCAS PARTNERS

(END OF APPENDIX A)