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

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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).

replace residential meters with new meters – most of the existing inventory will be retrofitted with communications modules and redeployed.[3]

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.

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[3] PG&E's plan is to retrofit 54% of the existing electric meters and 96.1% of its existing gas meters.

[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.

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 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.)

[5] Application (A.) 05-03-016, filed March 15, 2005.

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.

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

[6] There were 110 exhibits received into evidence – many were large multi-chaptered documents sponsored by several witnesses.

[7] Exs. 16, 17, 19, 20, 28 and 29.

[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 remaining objections on these issues.

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 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 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:

- o indemnify ratepayers against premature retirement prior to the end of PG&E's proposed 20-year life,
- o 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,

- o 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,
- o 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,
- o 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.

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 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

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[9] Ex. 1, p. 1-2.

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.

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[10] Ex. 11, Ch. 2, p. 2-9, and transcript, pp. 234 – 237.

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 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 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

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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.)

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 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.

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[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.

[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

Footnote continued on next page

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]

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

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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 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.)

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 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

[16] Ex. 1, Ch. 2, p. 2-13.

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

[17] Ex. 101, Ch. 2, p. 2-11.

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 …" (*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]

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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.

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.)

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.)

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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.)

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.

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

[22] Ex. 101, p. 2-15.

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 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."

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[23] See transcript, March 19, 2006, portions of which are confidential, and Ex. 11, chapters 4 & 5.

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 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

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[24] Ex. 11C, Chapter 4 for confidential warrantee terms**.** Ex. 11, pp. 5-1 – 5-3 for 20-year useful life.

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. 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.)

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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.

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

[27] Transcript, pp. 1334 – 1335.

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.

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.

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.)

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[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.

[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 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.

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 Power	$0.75/kWh (2-6pm)	$0.02720/kWh	$0.005/kWh (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

[31] Ex. 6, p. 1-1.

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 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.

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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.

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 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

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[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.

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

[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).

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. 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

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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.

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.

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

[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.)

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 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

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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

Footnote continued on next page

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.

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

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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.)

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.

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.

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

[45] Customer Preferences Market Research (CPMR): A Market Assessment of Time-Differentiated Rates Among Residential Customers in California, Momentum Market Intelligence, December 2003.

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,

[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.

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.

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]						TRC Value of Demand Response Estimates (20 Year Study Period[2])				
				Residential		Commercial and Industrial (C&I)		Rate Design Assumptions					
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.

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[47] Ex. 4, p. 3-15.

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.

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

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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.

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.)

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

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[51] Ex. 11, Ch. 14, p. 14-6.

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.

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 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

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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.)

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 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

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[53] Ex. 11, Ch. 15, Attachment 1.

[54] $8,000 x 12% = $960 - this is a simplified after-tax illustration.

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 base remained constant. TURN argues that the actual future benefits are so uncertain that its

[55] Ex. 201, p. 36-38.

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

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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.

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 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]

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[58] Opening Brief, p. 63, and referencing Ex. 11, p. 20-1.

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 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

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APPENDIX A

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(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)