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Commissioner	:	Michael R. Peevey
Admin. Law Judge	:	Michelle Cooke
DRA Witnesses	:	Robert Kinosian, Scarlett Liang-
	:	Uejio, Ralph Abbott, Edgar Quiroz, Anthony Fest, Cherie Chan, Louis Irwin, Marshal Enderby, and Thomas Renaghan

CALIFORNIA PUBLIC UTILITIES COMMISSION

DIVISION OF RATEPAYER ADVOCATES

Dana Appling, Director

TESTIMONY ON PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR AUTHORITY TO INCREASE REVENUE REQUIREMENTS TO RECOVER THE COSTS TO DEPLOY AN ADVANCED METERING INFRASTRUCTURE

APPLICATION NO. 05-06-028

REDACTED

San Francisco, California
January 18, 2006

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INTRODUCTION

This report was prepared by the Division of Ratepayer Advocates ("DRA") of the California Public Utilities Commission ("Commission") in Application Number 05-06-028. In this docket, the applicant requests authority to increase revenue requirements to recover the costs to deploy an advanced metering infrastructure. In this report DRA presents its analysis and recommendations associated with the applicant's request. Unredacted version of this report where provided to the Assigned Commissioner, Assigned Administrative Law Judge and Pacific Gas and Electric Company.

Christopher Blunt served as DRA's project coordinator in this review, and is responsible for the overall coordination in the preparation of this report. DRA's witnesses' prepared qualifications and testimony are contained in Appendix A of this report.

SECTION I

DRA'S POLICY AND RECOMMENDATIONS ON DEPLOYMENT OF AMI

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 1

EXECUTIVE SUMMARY

WITNESS: ROBERT KINOSIANS

I. INTRODUCTION AND SUMMARY

The Division of Ratepayer Advocates ("DRA") has reviewed Pacific Gas and Electric Company's ("PG&E") application requesting authority to implement an Advanced Metering Infrastructure ("AMI") and recover over $2 billion in costs for the AMI program from ratepayers. DRA has identified a number of areas where PG&E's application overstates the likely costs of the AMI project and understates the likely benefits of the project. With the modifications suggested by DRA, PG&E's AMI proposal is clearly cost-effective. DRA recommends that the Commission approve PG&E's proposal with the modifications identified herein.

Specific changes proposed by DRA's include:

- Increase PG&E's forecast of benefits to reflect reduction of theft and adequately train installers to look for signs of theft;
- Increase PG&E's forecast of benefits by reflecting a reduction in routine costs for meter replacement;
- Increase PG&E's forecast of Transmission & Distribution engineering and planning benefits to be consistent with the experience of other utilities;
- Reduce PG&E's forecast of Information Technology costs by $40 million;
- Reduce PG&E's proposed contingency costs by $41.8 million;
- Apply a cost cap or a risk sharing mechanism on cost overruns;
- Promote TOU rates and load control options in addition to PG&E's proposal to promote just new CPP rates;

- Implement a CPP rate that is based on a capacity value of $52/kW and does not alter existing Tier 1 and Tier 2 rates;
- Reduce forecasts of CPP-based demand response due to lower expected participation rates;
- Use 8.77 percent (PG&E's recently adopted after tax cost of capital) as the discount rate for calculating net present value of savings;
- Require PG&E to perform a study to improve implementation of the Commission's Conservation Voltage Reduction program using the new features made available by AMI;
- Require PG&E to present a comprehensive comparison of AMI costs and benefits with costs included in GRC rates to ensure that all areas of overlap and potential savings are identified.
- Allow DRA to independently audit the AMI rollout using a qualified outside organization on a reimbursable basis;
- Require PG&E to report quarterly to the Commission on costs incurred and benefits obtained, and any remedial actions taken to ensure that expected costs and benefits are realized;
- Require PG&E to develop, and submit to the Commission for approval, a plan augmenting the use of load control devices, including but not limited to the development of a radio or pager based non-proprietary broadcast system that would disseminate rate information and notification of CPP or curtailment events.

Many of these changes improve the overall cost effectiveness of PG&E's AMI proposal and some detract from the cost-effectiveness. Overall, DRA's changes significantly increase the expected savings from AMI compared to PG&E's forecasts. With DRA's assumptions, AMI appears cost-effective relying on operational savings alone, without the need to rely on relatively uncertain demand response benefits.

II. ENSURING RATEPAYER BENEFITS

PG&E's AMI application is relatively unique in that it involves a wide variety of costs and benefits in many disparate areas of the utility's business.

Some of the areas that the AMI proposal is anticipated to affect include: customer usage patterns; eliminating the need for on-site meter reading; making investments in transmission and distribution upgrades more efficiently; modifying PG&E's billing system; and greatly increasing the amount and precision of information gathered regarding the operation of the distribution system and customer demand. Benefits to consumers come not just in the form of cost savings, but also from improved service quality (such as reduced number and duration of outages), increased information regarding customer usage and expanded rate options giving consumers greater ability to control their bills.

Given this broad spectrum of impacts, costs and benefits from AMI, DRA has not just done a typical review of the accuracy of PG&E's estimates of costs and benefits (though many of DRA's recommendations address those concerns). A key aspect of DRA's review of PG&E's application is to ensure that, to the extent possible, all areas of benefits and costs that are likely to occur are identified, and once found, to ensure that the benefits will flow through to ratepayers.

By making use of DRA's consultant's (Plexus Research) knowledge of AMI technologies and using DRA's institutional experience, a number of areas have been identified where it appears PG&E has either failed to consider the potential benefits of AMI, or has failed to quantify those benefits. Reducing the costs that otherwise would be included in a GRC to replace old, worn-out meters is an example of the former, while reducing theft is an example of the latter. If benefits are not identified up front and planned for, it is possible that they will not occur, or that the benefits will not go to ratepayers, but instead go to PG&E's shareholders.

Despite DRA's efforts, there may be other areas of utility costs that will be reduced or offset by AMI that have not been addressed by PG&E, or found by DRA. In particular, a number of areas, such as replacement meter costs and CIS improvement/modification costs, should have reductions in amounts currently included in GRC funding due to the AMI project, but no such reductions are included in PG&E's listing of benefits. To ensure that the full benefits of AMI materialize and flow to ratepayers, DRA recommends that the Commission require PG&E to provide in this proceeding a complete comparison of costs included in current GRC rates, or that are included in PG&E's current GRC application that are likely to be affected by or overlap with proposed AMI expenditures.

III. DEALING WITH COST OVERRUNS

Ratepayer benefits may also be lost if PG&E is allowed to incur significant cost overruns without limits and without any incentive to constrain the costs of the AMI program. To ensure that ratepayer benefits are not negated due to cost overruns, DRA recommends that the Commission modify PG&E's cost recovery proposal. The Commission should either include a hard cap on the costs of the AMI program, or alternatively have PG&E shareholders be responsible for 10% of any cost overruns totaling up to $100 million, with cost overruns over $100 million being subject to reasonableness review.

This second approach was recently used in a settlement between DRA and PG&E on costs relating to PG&E's construction of the Contra Costa 8 power plant. It both provides an incentive to avoid cost overruns, and eliminates the need for an after-the-fact reasonableness review unless cost overruns exceed the $100 million threshold. As a further protection, DRA recommends that PG&E make filings with the Commission, at least quarterly, presenting the current status of the AMI rollout, including the amount of costs expended compared to forecast, and the number of installations performed compared to the proposed schedule.

In addition, to assure that both costs and benefits are realized as expected, DRA recommends that it be allowed to audit the status of the AMI rollout using a qualified outside organization on a reimbursable basis. This recommendation is further discussed in the testimony of Plexus Research.

IV. RATE DESIGN AND DEMAND RESPONSE BENEFITS

Another concern is that PG&E identifies demand reduction benefits relating solely to its proposed new Critical Peak Pricing ("CPP") rate. PG&E proposes to spend millions advertising this new rate, and assumes the only demand reduction benefits of AMI will come from this new rate. DRA recommends that PG&E broaden its focus to include two other areas where demand response benefits can be obtained: existing time of use ("TOU") rates and load control programs.

About 3 percent of PG&E's residential customers are currently on a TOU rate schedule, despite the requirement to pay a substantial additional fee to be on the rate. The AMI program will eliminate the need for the additional fee, making the existing TOU rate much more attractive to customers. Load control programs provide for the automatic reduction in a specific customer's usage in response to a signal sent remotely by the utility. PG&E has agreed to implement one such program, a small pilot program to test air conditioning cycling, in a current settlement proposed in the Commission's demand response proceeding (A.05-06-006 et al.). While air conditioning cycling could be implemented in the absence of an AMI system, having the AMI system will allow the utility to better monitor the hourly load reductions when air conditioners are cycled.

Regarding new rate options, PG&E and DRA are in agreement that new rate options such as CPP should be made available to ratepayers on a voluntary basis, rather than required. Some customers may prefer flat rates, some TOU rates, and some CPP rates. Customers should be able to choose the option that makes the most sense for them.

DRA, however, differs from PG&E on the imposition of new and potentially higher costs on Tier 1 and Tier 2 usage. DRA's proposed CPP rate does not alter the rates and costs charged to Tier 1 and Tier 2 usage to ensure compliance with legislative requirements contained in AB 1X.

V. OPEN ARCHITECTURE

Concerns have been expressed regarding the need for the communications aspects of AMI to use an open, non-proprietary technology. DRA's consultant addresses this issue at length in Chapter 2 of this testimony. PG&E's current agreement with DCSI calls for DCSI to make it's proprietary technology available at "reasonable" terms. While it would be beneficial to obtain stronger assurances from DCSI that its proprietary technology will not be a roadblock to fully exploiting the capabilities of the AMI system, DRA does not believe that open architecture should be a requirement of AMI. Nor does it believe that PG&E's proposed rollout should be delayed in order to resolve open architecture standards.

As addressed in Chapter 2, other low cost, non-proprietary technologies, such as paging and radio systems, already exist that can be implemented to provide communications to individual customers. DRA recommends that the Commission expeditiously explore the development of such options and the ability to expand and enhance the use of load control devices. PG&E should be required to present a plan to carry out this recommendation for Commission approval in the near future. Developing such a system could proceed in parallel with PG&E's proposed AMI rollout.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 2

FUNCTIONALITY CRITERIA, TECHNOLOGY, AND VENDOR SELECTION ISSUES

WITNESS: RALPH ABBOTT

I. INTRODUCTION

I was asked by the Commission's Division of Ratepayer Advocates to evaluate PG&E's Advanced Metering Infrastructure ("AMI") proposal and to provide my opinion and recommendation on whether, from a ratepayer perspective, the Commission should approve the proposal, either as proposed or with modifications. This is the first of six questions that the Commission plans to address in this case, as set forth in the Scoping Memo[1], and it encompasses the following sub-parts:

1. whether the proposed system meets the functionality criteria previously identified by the Commission,
2. whether it reflects an appropriate choice of technology,
3. whether the system provides sufficient functionality to warrant ratepayer investment in it,
4. whether timing of the project is appropriate, and whether PG&E's plan for integrating the AMI system is adequate to ensure that the expected benefits accrue,
5. whether the costs and benefits have been appropriately identified,
6. whether the project is cost-effective, and

[1] Assigned Commissioner's Ruling Establishing Scope, Schedule, and Procedures for Proceeding, dated July 27, 2005 (Scoping Memo).

7. Whether the proposed project is the preferred way to accomplish the operational and demand response objectives PG&E has set forth for the project.[2]

These questions are addressed in my testimony.

In summary:

1. The proposed system does meet the functionality criteria previously identified by the Commission.
2. The technology choice is reasonable. It is one of several choices that would have been reasonable.
3. The selected system does provide sufficient functionality to justify a ratepayer investment in that system. It is important that PG&E be diligent about extracting the fullest measure of functionality consistent with improving customer service and reducing costs, especially functions of the system which benefit consumers but which may not necessarily have financial consequences for PG&E shareholders. Detection of theft of energy is such a function.
4. The timing of the project is appropriate. The interests of ratepayers are not well serving by delaying the proposed implementation. The installation schedule is quite aggressive and challenging, and will require careful management to avoid unforeseen delays, with associated cost consequences.
5. Costs for the AMI system and its installation appear to be generally in line with other similar projects in other utilities. Many utilities are able to economically justify these systems on the basis of the operational benefits they provide without consideration of demand response. PG&E's proposal comes close; claiming 89 percent[3] of

[2] Scoping Memo, pp. 2-3.

[3] This percentage is about 81 percent using DRA's recommended discount rate.

the cost is justified by operational benefits, with the remaining justification coming from demand response benefits. In fact, it appears that other operational benefits not recognized by PG&E could also bridge that gap. Moreover, there are further benefits to customers that are significant but not quantified.

6. The proposed approach is a reasonable approach given the multitude of tradeoffs including cost, supported features, "fit" with PG&E territory and infrastructure, risk, vendor experience, ability to meet schedule, and terms reached in contract negotiations. The proposed approach is not the only combination of technologies, vendors, and implementation strategy that would achieve a similar result. I believe that Commission approval of PG&E's application, subject to conditions discussed later in this testimony is in the best interests of the PG&E customer.

The proposed PG&E approach to implementing AMI system-wide encompasses more than 5 million electric customers and 4 million gas customers (in other words, full deployment throughout PG&E's service territory). If implemented, this would be the largest system of its kind in the United States, and will be a pioneering undertaking in terms of scale. It will not be, however, unique in other respects. Other major investor-owned utilities have been installing large 2-way[4], fixed network[5] AMI systems for more than 20 years. This experience has

[4] Two-way AMI systems send data from the customer site (usually from the customer's meter) to the utility, and also can receive data and commands from the utility at the customer site. Data inbound to the utility may typically include metering data, status flags for outage or tampering, voltage and other information. Outbound data from the utility to the customer site may include polling for data, commands for load control, data indicating price or peak periods, etc.

[5] -A fixed network AMI system is one that with communication infrastructure fixed in place and always-available to support the one-way or two-way communication between the utility and the customer site, without need for personnel or vehicle in the field to collect data. Examples of fixed networks include the telephone system, utility owned radio networks, and the power lines. The alternative to a fixed network is a communication method that is not always in place, such as a roving van.

generated a formidable body of industry knowledge and experience, best practices, technical refinement, system reliability, risk mitigation techniques, and cost reductions that make it possible to define criteria by which the PG&E proposal may be measured.

PG&E's proposal comes at a time when California's regulatory agencies have urged the implementation of electric rate structures that will more appropriately track costs and that will provide "price signals" to consumers that may deter or defer consumption from peak periods. More complex rates designs, particularly Critical Peak Pricing ("CPP") rates, require more capable metering and meter data retrieval systems than are currently in place. PG&E has proposed an AMI system that will be capable of acquiring the data to support any reasonably foreseeable complex electric rate structure, including time-of-use ("TOU") and CPP rates for all its electric customers. PG&E has addressed the associated requirement to notify customers when price changes are imminent, but should be required to use additional and more effective methods to disseminate these critical messages regarding prices or prices changes. PG&E should develop other customer response tools to enable customers on CPP rates to respond more effectively. It is not essential that the enabling communication be the same as that used by the AMI system. In fact, communication via open paging, VHF or other RF communications is preferable.

Many utilities have been able to economically justify procuring similar 2-way, fixed network, AMI systems implementing innovative rate structures. These justifications combine the benefits obtained from the various capabilities of an AMI system. For example, the reduction in meter reading labor cost is usually a prominent benefit. There are many other pools of benefits, ranging from improving the response to unscheduled outages and improvements in distribution engineering, to detection of some forms of theft of service. The suite of benefits, and their value, is different for each utility. PG&E has estimated that almost 90 percent of the installed cost of the proposed system is justified by utility applications quite apart from innovative rates or demand response objectives. I believe that justification is conservative, and that PG&E could make a strong case that the operational benefits are enough to pay for the system. Moreover, I know of no utility that, having installed an AMI system did not identify and capture operating benefits above and beyond its original expectations. For these broad reasons we believe that PG&E's decision to seek approval to begin installation of system-wide AMI promptly under an ambitious schedule is a good decision. In our testimony, we explain in more detail the basis for this conclusion.

Once a utility has decided to proceed with some form of AMI system, the next questions are directed toward the very important details. Which technologies? Which vendors? At what cost? At what speed? In what areas? Under what oversight? Conforming to what standards? What steps must be taken to ensure that the potential benefits of AMI are realized? The process through which PG&E arrived at answers to these questions appears to have had its share of mistakes and shortcomings, but the end result is a proposal that is generally reasonable in terms of choice of technology. The proposed approach is one of several technology/vendor approaches that would produce a similar result. My testimony will deal with specific aspects of the approach proposed by PG&E. In some respects PG&E's approach appears to be sound and solid. In other respects the approach taken is questionable or may need fine tuning. And in certain respects the proposed PG&E approach is clearly deficient.

II. FUNCTIONALITY CRITERIA, TECHNOLOGY, AND VENDOR SELECTION ISSUES

A. <u>Technology Choice Issues</u>

Q: ***Does the proposed system meet the functionality criteria set forth in the May 18, 2005 ACR?***

A: Generally, yes. However, it is worth noting that PG&E treated those functionality criteria as requirements, even though the Commission said it would decide later whether a system with less functionality might be preferable, basing that determination on the specific applications before it.

In providing advance guidance on AMI system functionality, the Commission stated:

> "The purpose of an AMI system is to provide the metering and communications capacity to economically support a wide variety of rate and associated customer service options. The ideal AMI system will maximize the amount of demand response that can be achieved cost effectively. We do not know a *priori* the particular mix of rates, programs, and customer service functions that will meet this cost effective ideal. Thus it makes sense to analyze an AMI system that supports a wide variety of potential rate structures and customer service options that the Commission may approve over the useful life of the AMI system.
>
> As indicated in the original rulemaking, we prefer to take a broad view of the investigation of AMI. The Commission can always authorize a narrow scope AMI system implantation if warranted, but it is more difficult to expand functionality if it has not been considered in the business case analysis. Therefore, the AMI system *analyzed* should support the following six functions: [list of functionality criteria]".

(Source: R.02-06-001, Joint Assigned Commission and ALJ Ruling providing guidance for the AMI Business Case Analysis dated February , 19, 2004, pp. 2-3)

Q: ***Has the utility made a wise choice among available technologies?***

A: Generally, yes.

AMI systems tend to be characterized by the technology used for communicating data from the meter to a data collector at some higher level of the system. The electric AMI system selected by PG&E uses power line communications and is capable of supporting the metering requirements for TOU and CPP rates, and virtually any other innovative rate being considered for residential and small commercial applications. The technology is two-way, with inbound (customer to utility) retrieval of metering data, and outbound (utility to customer) communications for commands, such as load control. It has the potential to handle dissemination of rudimentary customer alerting and notification signals. The technology is mature and proven in several other large scale applications. The additional development required for this project appears to be evolutionary in nature and of relatively low risk.

The gas AMI system selected by PG&E uses radio frequency ("RF") communications, and appears to be a good choice among several others having similar attributes.

It is possible to use the power line AMI system PG&E chose for the electric applications to carry the gas meter data. A short-range battery-powered transmitter can be fitted to the gas meter encoder that communicates with a receiver at the electric meter. Or data wiring can be run from the gas meter to the electric meter data communications device. Both of these approaches have distinct drawbacks. And gas meters are often at some distance from the electric service, which makes it inconvenient to use powerline communications.

Most gas AMI systems are RF based, communicating from the gas meter dial/encoder with a battery-powered device to a nearby data collector (not in the electric meter). Since the data collector *must* be nearby for the radio communication to operate economically, RF systems require a certain minimum density of customers per square mile. PG&E's gas service is primarily in areas of reasonable population density, so an RF system is a reasonable choice.

Q: ***Would different communication systems be better in urban versus rural applications?***

A: Given the diverse nature of PG&E's service territory, a full-coverage AMI system for electric and gas that covered PG&E's service territory would necessarily include two separate communication technologies at the meter module level. These would be radio frequency and powerline communications ("PLC").

Radio frequency systems are, in my experience, sometimes less costly in urban environments having relatively high customer density or even in rural applications where customers are clustered, while PLC tends to be less costly in areas with lower customer density. This really comes down to how the costs of the communication infrastructure can be allocated. As noted previously, RF systems are also sometimes less costly for gas and water metering because the power lines may be relatively far away from the meters.

An RF system could be suitable in a rural setting if the rural residences are clustered. Radio nodes can serve villages and commercial parks, and an occasional directional antenna can be used to connect concentrators to backhaul, all less expensively than a power line system that incurs full substation equipment cost for relatively few customers.

Which communication technology goes where? We could choose one communication technology for electric metering and another for gas metering. PG&E made that choice. There would be several reasons for seriously considering PLC for the electric application, prominently including the aforementioned ability to economically communicate with electric meters in the deep rural environment, areas with low customer density. The communications infrastructure for PLC resides in the distribution substation, and the communications generally propagate well throughout the distribution system. Thus, long distances and low density are not a serious economic challenge.

Gas service is generally not extended to very rural areas because the pipeline infrastructure is simply too costly on a per-customer basis. Similarly, RF AMI systems must have distributed infrastructure that needs more customers to share the cost of that infrastructure. That can make RF AMI comparatively more costly than PLC for rural applications.

Another approach to the electric versus gas and urban versus rural options would be to select AMI communication technologies on the basis of customer density per square mile, contrasting urban, suburban and rural populations. In this approach, RF would be used for both electric and gas AMI in high density areas, and PLC would be used for marginal and low density applications.

Could the PLC system also do the gas metering? Yes, but while that is technically possible, it probably is more costly and technically cumbersome than alternatives, and involves either short-range RF links at the customer's premises to bring gas information to the electric meter, or a hardwire doing the same thing.

If PG&E had chosen any one of several available RF systems for electric metering in urban environments, that same RF system might have easily also accommodated gas and water metering. But such a system could be uneconomic in some suburban and most rural settings. Therefore, PG&E probably would have selected a PLC system for certain suburban and rural customers.

After reviewing PG&E's choices and deliberations, I believe that the technology choices are reasonable. By selecting a PLC system for all electric metering, PG&E is able to provide economical and ubiquitous coverage to its electric customers, and to support identical service options to all customers.

Q. Should two separate communication systems be installed for gas and electric meters, or would an integrated communication system be feasible and more cost effective?

A. This decision would normally be made entirely on economic grounds. Installation complexity and cost are part of this consideration. Mixed technology systems, tailored to the applications and as proposed by a number of highly competent firms, would ordinarily be a more attractive choice than stretching the capabilities of a single communications technology. But technical issues also intrude. As noted above, certain coverage and timing limitations of a proposed RF system appeared to limit its suitability for certain applications on the electric side. PG&E has identified a number of valid reasons for selecting technologies that will be consistent throughout their territory, including the ability to offer certain service options and to obtain consistent operating benefits and practices universally throughout its territory.

Other important performance factors come into this discussion as well. Which technologies can provide the highest level of assured coverage? The difference between guaranteeing 98 percent of daily readings (as does the RF solution) versus guaranteeing 99 percent of daily readings (the PLC solution) is a large number of customers (>50,000) in PG&E's case.

PG&E established other technical performance requirements. For example, PG&E stipulated that its AMI system must provide hourly readings taken within 3 minutes of the hour.[6] This requirement appeared to be challenging for one or more of the RF suppliers, and potentially could be achieved only with extra infrastructure and associated cost. Were PG&E's requirements "over-specified?" If the requirement for retrieval of hourly metering data on all customers was not a

[6] See Data Request ORA_030-01-1 page 58, PG&E Response to Question 1.

requirement or was relaxed to a smaller subset of the customer, could there have been either lower cost or more vendors whose systems satisfied those requirements? The elimination or reduction of the requirement for hourly data from all customers could have permitted other vendors' systems to appear more responsive to PG&E's requirements, and also could have permitted modest cost reductions in the selected system. But there are advantages to having hourly data that may justify the modest cost premium, if there is one.

Q: Should more of the functionality of the AMI system be embedded in the meters or in the hardware and software upstream of the meter?

A: The systems selected by PG&E are reasonable, relatively mature, and have evolved to strike an acceptable balance in cost, functionality and flexibility. These selected AMI systems, and others that are competitive with them, are highly optimized and are tailored to strike a suitable cost/function balance for certain sets of utility needs (e.g. one-way versus two-way, meter reading only or meter reading and load control, interval metering on a saturation basis, support of complex rates, etc.). Each vendor takes its best shot at what utility needs are and will be, and directs its costly development and production accordingly.

The clear trend has been to keep the meter and meter data communication module as simple and low cost as possible, since there are such a large number of them, and to concentrate processing power, memory, and cost at higher levels of the system hierarchy. PG&E's proposal is consistent with this trend.

B. <u>Issues Associated with Deferring PG&E's AMI Deployment</u>

Q: Are there potential benefits in postponing the AMI investments pending further developments of the technology? Would it make sense to postpone deployment to allow the incorporation of BPL technology?

A: I see no clear benefits in postponing the deployment of the AMI systems. There are always new technologies "just around the corner." Some utilities engage in perpetual pilot testing. No sooner than a one or two year pilot test concludes, a new technology appears, justifying another one or two year pilot test. I have worked with utilities on AMI applications for more than 30 years. Most often it is the innovative, progressive, customer-oriented utilities that are eager to employ technology to reduce costs and improve customer service. These utilities do not leap blindly into large commitments, however. A careful risk assessment is essential.

AMI provides substantial benefits. It will be better to wait only if new technology will—with high certainty—increase those benefits enough to more than make up the benefits lost by waiting. But waiting often is motivated by the appeal of newly developed features or technologies, and that introduces risks that discount the future value of the system. A proven track record is a very substantial element of risk mitigation.

The PLC technology that PG&E has selected had its early developmental roots in the mid 1970s, and has been refined since that time. Similarly, the spread-spectrum radio of the gas AMI system had its technical roots in the mid 1980s. These technologies have been refined and polished, as you would want them to be when you talk seriously about installing nine million such devices into the harsh outdoor field environment where you expect a twenty-year unattended lifetime of reliable service.

I believe that it would be imprudent for PG&E to deploy any AMI technology system-wide that did not have years of successful operation in moderately large systems and widely varying environments. Even with relatively mature technology there can be a latent defect in materials or in a manufacturing process that can pop up a few years later requiring the recall of thousands or millions of devices at a huge cost and disruption to operations. One of the major AMI providers experienced such a problem a few years ago that necessitated the recall and replacement of four million meter modules. The AMI provider didn't cause the problem, but moved quickly to remedy the problem nonetheless. The problem related to faulty materials used by one of its circuit suppliers. My point is that, even with mature AMI communication technology, there is the further stability and maturity of specific product designs that comes only with field experience.

BPL is sometimes suggested as an attractive alternative for AMI systems. BPL, however, is in its early developmental stages. There are aspects of BPL technology that may be technically suitable for certain AMI applications, but its obvious "killer application" is provisioning broadband service to consumers in un-served and underserved areas. Yet BPL systems have infrastructure costs that are economically challenged in suburban and rural applications, much as RF-based AMI systems are challenged in these environments. The economics of BPL works better in large urban areas, but such areas typically are already well-equipped with broadband alternatives, rendering BPL potentially uncompetitive.

Utility AMI applications do not require broadband data rates. BPL is finding a special niche in certain "sweet spots" such as campuses, commercial complexes, hotels, office buildings and office parks, condo complexes, housing developments, and municipalities. Some utilities are expressing active interest in BPL as the potential data communication platform for the "utility of the future" or "Smart Grid." That vision, if fulfilled, may eventually justify its ubiquitous deployment in the utility's distribution system, even including areas in which it has no consumer broadband service potential. The DCSI "TWACS"™ technology selected by PG&E will propagate throughout the distribution system, and can support certain distribution automation functions. Yes, this system is quite slow. It is certainly not broadband! But it can move data throughout the distribution system without repeaters or regenerators or other communications infrastructure additions to the distribution system.

I do not believe that BPL is now a candidate as a coherent, proven, ubiquitous AMI solution for all of PG&E's electric and gas customers. That may not happen for another five to ten years, if ever. However, BPL may very well meet other utility objectives or consumer broadband access objectives on a more localized basis within this timeframe.

Q: Does PG&E's proposed AMI system allow for a level of upgrading and expansion as AMI technologies evolve in the future?

A: The proposed technology/vendor selections are reasonably flexible in the range of applications they are capable of serving. The PLC system has a comparatively slow communications throughput that is challenged to provide hourly data from all customers, and may be limited in more data-intensive applications in the future. But the systems seem adequate for most reasonably foreseeable applications and for all electric rate designs under current discussion. It can collect hourly data, and this enables great flexibility in rates.

Most AMI systems are projected to have a 10 to 15 year economic life. Because the cost of installation is formidable, AMI systems, like the meters themselves, must have a longer useful life. PG&E is projecting the life of the system at 20 years. I believe that the system can be sustained technically for 20 years, but it is possible that 20 years hence the system will be functionally obsolete in comparison with other options at that time. Enhancements that most certainly will be developed by the supplier will be offered, but the fundamental limitations of the technology will obviously persist. This risk of technological obsolescence must be weighed against that of adopting unproven technologies with potentially higher functionality but much greater risk of serious operational deficiencies. I believe the balance favors the use of the more standard, well-proven technologies.

Q: Has the utility's selection of AMI technologies adequately addressed the advantages and disadvantages of open architecture (also called "open

standards")? What requirements of open standards are suggested for PUC adoption in the case?

A: In my opinion the utility has made reasonable choices. This is a major investment, and it makes no sense to procure anything other than a mature, highly integrated and well proven technology from established vendors with solid track records. The selected AMI systems are reasonably mature and suitably capable. They are products of years of refinement and evolution.

Each prominent system has some degrees of openness - typically at the higher levels in the meter data retrieval system architecture. There is essentially no interoperability among vendors at the meter module level. Accordingly, the proposed AMI systems are representative of what is generally available and likely to be available for at least several years into the future. Based upon my frequent and routine interactions with the leading AMI vendors, I believe that there is no serious likelihood that these vendors will adopt open communications interoperability standards at the meter module level within the next five years. The major suppliers have huge investments in the research, development and engineering refinement of their respective technologies. These vested interests constitute a major impediment to developing voluntary, industry-designed standards. And if such standards are adopted by new or established suppliers, and then rolled into product designs, even more years will pass before the inevitable bugs and design changes are worked out sufficiently to justify deployment in the millions of meters.

However, currently there are two distinct opportunities for open interfaces and broader vendor participation. PG&E has not adequately taken advantage of these opportunities. The first of these is in the service disconnect collar. PG&E plans to install up to 600,000 such devices. [See PG&E Submission A-05-03-028 (Phase II), Exhibit 2, Chapter 4, Workpapers, sum of cells J410 to O410.] The disconnect collar, with it's disconnect relay, is essentially a generic device that could be manufactured by a number of competing suppliers. Its mechanical and electrical interfaces can be open or non-proprietary, or readily made to be standards-based.

Separate competitive bidding for the disconnect collar, outside the contract for the AMI meter data communications, should be straightforward. The interface is simple. Competitive bidding may or may not produce a better price than what was already bid to PG&E. But PG&E's requirements are likely to extend over time, rather than a simple large one-time order. So economic periodic batch procurements should be possible in the future. There seems to be no good reason for PG&E not to procure these devices from any of several suppliers, and no reason to incur any cost markup by purchasing these devices from an AMI supplier when it can be purchased directly from third party manufacturers.

In addition, PG&E proposed initial purchase of 600,000 collars appears to be more than PG&E would need to install for many, many years. Having a large number of collars sitting in storage for a period of years before they are needed to be installed, if ever, is wasteful and costly to ratepayers. I recommend that the initial amount of collars PG&E purchases be reduced from 600,000 down to the amount of collars that PG&E plans to install in the following one to two years. Additional purchases can be made as necessary, with the need and cost for such additional purchases addressed in GRCs. This will reduce the total initial purchase cost, reduce the need to store large numbers of collars in inventory, reduce ongoing depreciation and return costs, and ensure that collars aren't subject to obsolescence or other devaluation while sitting in storage.

The second substantial opportunity for open standards lies in the means by which the utility communicates information about CPP events to customers, and the use of technology to make it easier for customers to respond to critical peak pricing rates. The telephone notification approach proposed by PG&E is inadequate. PG&E should be required to disseminate peak period pricing or timing data by several parallel wide-area, non-proprietary means instead of or in addition to the telephone approach described by PG&E. Simple customer-installed smart thermostats, load control devices and peak notification devices that use paging, utility VHF-RF or other radio approaches will quickly foster a lively aftermarket of devices that can receive and respond to utility transmissions. Such products already exist. Smart communicating thermostats may be purchased now from multiple vendors[7] in the $130 to $180 price range for quantities of 10,000 and more. Similarly, commercial grade remote load control devices are available in the $60 to $100 range.

PG&E's contract with DCSI provides that DCSI will license its technology for such control and notification devices for a reasonable fee.[8] That is a positive development, but is not enough to achieve the independence from the proprietary technology that would be very desirable.

Moreover, there are several simpler, "open" and less expensive solutions that don't involve PLC communication, regardless of the terms of licensing the DCSI technology. A variety of customer notification and control devices based on a range of outbound utility notification media, independent of the PLC AMI system, is readily achieved.

It is very easy and inexpensive for a utility to send outbound information on a global broadcast basis. This is information that is heard by lots of devices, a simple message such as price or time "$0.38 now", or simply that the super-peak is NOW ON and will be NOW OFF when I send that message, or that price is

[7] Just as examples: Cannon Technologies, Comverge, Honeywell, and Lightstat. And there are others.

[8] AMI System Supply Agreement Volume 1 between Pacific Gas & Electric Company and Distribution Control Systems, Inc., Effective Date November 3, 2005, page 16, paragraph 14.3.

BLINKING RED, RED, AMBER, or GREEN. Or simply that the super-peak is NOW ON and will be NOW OFF. Those kinds of messages should be sent on various media, and various devices can be sold at retail to hear them. Devices can automatically react to this information for the benefit of the consumer (e.g., smart thermostats or load control), or these messages can simply be displayed with an audio alert for members of the household.

It is a more costly and complex matter to send uniquely addressable outbound data to a single customer (times many customers), but this is readily accomplished with paging and other broadcast technology. Finally, it is yet more costly and complex if there is a uniquely addressable two-way communication with the remote device, as might be required for remote reprogramming of a smart thermostat or control device, or local display of consumption based on actual metered data, first retrieved by the utility, then sent to the consumer.

I feel strongly that the first of these options, the "global broadcast" of information on the price points and CPP events is a must. It is cheap and easy for the utility, and allows lots of companies to build low cost customer response devices. The addressable communications with the customers, whether one or two way, is technically straightforward and is being done. But it is more complex and costly, and is likely to be of interest to only a small subset of residential customers. I urge that PG&E be required, at a minimum, to provide non-proprietary wide-area RF communications to customer notification devices. The Commission should expeditiously address proposals for load control programs and related communication technology and implement such programs as soon as possible.

There are other areas in which standards already exist and are essential. One is the integration of the AMI field infrastructure to the system head-end. Another is in the head-end system itself.

PLC systems generally inject and extract communication signals from a communication device in the utility's substation. It, in turn, must communicate with the AMI system head-end. This communication must be standards-based to allow ready integration with public telephone (POTS), licensed RF, microwave, fiber, or IP addressable infrastructure. Every prominent AMI system (including those selected by PG&E) already uses standards-based communication at this level.

A second area in which standards currently exist and are essential is at the system head end. The AMI supplier furnishes a computer system that is essentially a network management system, calling the shots of the operation of all AMI infrastructure in the field, and issuing the commands and receiving the data from the field. These data, once recovered and suitably checked and time-tagged, are then handed off to a number of systems that will use the data for billing, customer inquiries, engineering applications, outage detection and management, meter tampering detection, etc. The entire chorus of data communications among these head-end systems is standards-based. These standards pertain to electrical interfaces and to data formats. I mention this to point out that standards have been adopted by AMI suppliers when it is necessary or advantageous to them to do so.

Q: What are the feasibility, advantages and disadvantages of deferring PG&E's AMI deployment to enable all three utilities to install similar AMI systems statewide with uniform functionality?

A: In my view, it is not unreasonable to require similar functionality statewide, but is unreasonable to dictate how that functionality shall be achieved. There are many excellent AMI systems, each with particular strengths and weaknesses. Other California utilities may have compelling arguments for choosing one approach over another that are quite different from those ventured by PG&E, particularly on the extent to which the benefits of the AMI systems are obtained though operational features of the system. Other utilities may not have the same benefits available because they may already be captured by some other means. For example, some AMI systems produce significant benefits in the area of distribution operations that are important to utilities that don't have much distribution-level automation. Other utilities may already have rather elaborate or more competent systems in place that achieve or surpass the same result.

Other utilities may place a greater reliance on other forms of demand response, other rate designs, incorporation of varying degrees of load control, or utilization of existing wide-area communications facilities. So some considerable flexibility in choice of AMI technologies by utilities should be afforded. Yet I strongly disagree with some who might argue that customer response technologies must be part of the AMI system.

It is clear that there is room for the state-level promulgation of requirements in the customer response technology area. Customers must have tools to respond to whatever rates are imposed or offered. Already a number of smart thermostats are available that can respond to paging, VHF radio and even certain PLC signals. The state can make it a requirement that all utilities adopt multiple open technologies for customer notification of CPP rates and for certain energy management applications, such as remotely adjusting temperature setpoints or automatically interrupting certain customer-selected loads during critical or high-priced periods. Production versions of these devices already exist, and other innovative customer response products can be developed by other suppliers. This ensures innovation and lower costs. These devices could be offered by the utility for rent or for sale, or could be sold through consumer outlets such as Radio Shack or K-Mart.

Some of these customer interface devices may incorporate the same PLC or RF technology as that used for meter data communication. But they certainly do not need to if PG&E will commit to message dissemination by other "open" means. In fact, it is very desirable that several open alternatives to AMI communications be available that have nothing to do with AMI meter data communications. Customers have different needs. Some are home during the day and can react to visual or audible cues. Others are not home and want technology to curtail non-essential uses during high priced periods. Some want notification wherever they are, not necessarily near a phone. All of these needs are readily accommodated with currently available technology. None can happen without multiple open signaling alternatives for notification and control.

A free and open market for customer response technologies is needed, and consumers will need some level of assurance that the customer response equipment they buy will indeed respond to messages their utility will send. Thus, some form of certification by the state or preferably by the utility will be required. This seal or certification will assure the customer that the product was tested and is compatible with the open notification and control messaging services established by the utility.

C. <u>Vendor Selection Issues</u>

Q: Mr. Abbott, It sounds like you agree with essentially all of PG&E's actions and conclusions. Is that right?

A: On the contrary, it appears PG&E made numerous substantial missteps, some of which have made it difficult for PG&E to conduct this process in a lucid and productive manner. For example, the Commission postulated a requirement for AMI systems to collect hourly meter data from every meter. The Commission instructed the investor-owned utilities to examine what combination of capabilities—up to and including this hourly capability—produces the best result for the utility and the ratepayers.[9] Yet, in its acquisition process, PG&E presented the hourly capability as a requirement, and appears not to have considered the

[9] See OIR.02-06-001, Ruling Providing Guidance for the AMI Business Case (February 19, 2004).

cost/value balance of combinations of capabilities that exclude hourly meter reading.

PG&E did prepare certain summaries of the costs, capabilities and benefits of some AMI alternatives that it considered and rejected. In my experience these summaries fell short of fully explaining the reasons for the final selection of the chosen vendors and the rejection of other vendors.

Q. Could you explain further in what ways was there a lack of clarity in the selection of AMI systems?

In most AMI projects a business case is developed that first establishes the overall benefits of a hypothetical AMI system. The "benefit side" of the case establishes the functions where the most significant benefits are to be found, which applications provide the most "yield". These important applications become the drivers for the basic requirements, and are written in the functional specification for the required AMI system. Other functions having lower or uncertain value, or whose value is difficult to quantify, and may be presented in the specifications as desired, non-essential or optional.

In selecting a specific vendor's approach, utilities normally use a rigorous evaluation system that rates the leading proposals in terms of how well the proposed system can perform the required and desired functions that have been specified. Scoring the technical, management, and cost components of the proposals should produce a crisp, clear and coherent basis for selecting a short list of suppliers for clarification and negotiation. PG&E stated in an informal discovery meeting (briefing held on December 1, 2005) that it received 70 proposals from 40 suppliers. Such a large response typically indicates poorly specified system procurement. It appears that the Request for Proposals phase of activity may have been more of a fishing expedition than a tightly specified set of requirements against which a small number of qualified proposals could be scored.

Normally, utilities engaged in this process prepare a simple table or chart showing the installed cost per meter point, fully burdened by all applicable costs, and for each of the responsive technical approaches proposed by qualified suppliers in response to RFP. This cost portrayal should be based on "best and final" pricing of the top four to eight suppliers. The chart should contain cost adjustments for all utility furnished equipment and services, resulting in a clear complete, all-in cost picture. The chart should mention critical non-financial considerations, such as experience, that might have bearing on a selection. Such a summary portrayal is normally required to support management review and decision. Apparently PG&E did not prepare such a chart. (See Data Request Set DR-ORA-36, response to question 1). In view of the size and importance of this investment, I am surprised that PG&E has not provided crisp, clear and coherent support of its selection.

In spite of these problems, PG&E seems to have arrived at reasonable choices in its technology and vendor selections with a patchwork of justification and analysis, some of which is excellent and some of which is superficial. My belief that PG&E should move forward with its AMI deployment is influenced by my experiences with other utilities as much as by the PG&E materials and analysis that I have seen.

Q. What other problems existed in PG&E's selection process?

There is a bias in PG&E's selection process against solid state residential watthour meters. PG&E selected traditional induction (electro-mechanical) meters. Many other utilities now take advantage of an AMI installation to upgrade meters to all solid state meters, especially now that solid state meters with integral AMI are often comparable in cost to the electro-mechanical alternative of a new induction meter with a bolt-in module. A common strategy is to retrofit electro-mechanical meters that are up to 15 years old, and replace all older meters with solid state meters with integral AMI. This decision is usually driven by the economic difficulty of writing down meters that still have significant depreciable value. PG&E's approach is not unreasonable; I simply have not seen sufficient data to explore the tradeoff.

Q: Has the utility struck an appropriate balance between cost, risk and functionality in the proposed AMI systems?

The utility choices are reasonable, and will support the objective of offering Critical Peak Pricing ("CPP") rates to all customers. But there is always a question about how much cost and complexity is added when one imposes greater complexity in the metering data or supported rate designs.

Could the cost of the system be appreciably reduced if simpler rates were used, for example, a three-part Time of Use ("TOU") rate? Some AMI systems support a three-part TOU rate using drastically lower data throughput than is required to recover hourly data from all meters. Only three billing determinants are needed from each meter instead of 720 hourly readings per month.[10] The time boundaries of those "three bins" of consumption can be selected remotely. But most of the cost of an AMI system exists in the meter, the communication module, installation, and the field communications infrastructure, even to do a simple once-a-month meter reading.

It is not necessary to have hourly data to implement TOU or CPP rates. It appears that PG&E may have over-specified its requirements by dictating how the data is to be collected, rather than simply stating what rate designs the AMI system must support. This may have precluded consideration of one or more vendors who can provide billing determinants for CPP and TOU rates without collecting hourly data.

[10] With some AMI systems a three-part TOU rate would be the equivalent of three meter readings per month from a customer. In other AMI systems by different vendors, the three billing determinants (off-peak, shoulder-peak and on-peak) are assembled from much more frequent readings, and certainly can be assembled from hourly data.

The requirement to gather and maintain hourly data on all customers does add cost compared with a once-a-month reading. This increase in cost is prominent in two places. First, the wide area data collection infrastructure frequently must be expanded to transfer the much greater volume of data that goes with collecting hourly data. But this may add just a few percentage points to the overall cost of the system. The other place that costs are increased is at the system head-end, especially the utility's legacy systems, which now are suddenly dealing with a 720-fold increase in the amount of data that must be actively handled and warehoused. That expansion in data manipulation and storage happens regardless of the technology selected if hourly data is specified as a requirement.

Accordingly, I do not see any substantial cost difference between a system capable of supporting CPP rates over simple TOU rates. As noted, the requirement for hourly data does, however, add modest cost and complexity, primarily at the IT level and to a lesser degree at the AMI system level. This cost impact is too slight to drive technology selection decisions. However, a more disturbing consequence of requiring hourly data from all customers, when hourly data may not be needed, is that it precludes consideration of some vendors and technologies whose systems can support the target rate designs, including TOU and CPP.

The costs of the meter and its communication module appear to be generally in line with other recent AMI system procurements I am familiar with. The installed cost per meter point of the overall system also appears to be in the middle of the expected range. But there are several shortcomings in the details of the proposed implementation, extraction of benefits and opportunities for cost reduction, discussed below.

D. Potential Benefits PG&E Did Not Consider or Quantify

Q: Does PG&E aim to achieve a sufficiently complete range of benefits to its customers and its shareholders, including benefits that are real, but difficult to quantify?

A: PG&E appears to have paid comparatively little attention to benefits that do not affect PG&E financially but which may significantly affect the consumer. Specifically, this includes the benefits of detecting and deterring theft of service, both during installation and thereafter through detection measures provided by the AMI system. There is a benefit in revenue recovery from customers found to be stealing, and this allows rates to be reduced even though it may not affect the total revenue requirement. It reduces the bills of paying customers who are now subsidizing those others who steal. A 1992 article in a prominent energy industry publication quoted PG&E as follows: "PG&E projects it will lose $110 million to energy theft…. Ratepayers will end up absorbing these costs to the tune of $25 to $75 each."[11] Yet the detection and reduction in theft of service (also sometimes called "current diversion" or "meter tampering") that accompany major AMI installations appear not to have been treated as a financial benefit to PG&E. Inasmuch as PG&E apparently has no financial incentive to reduce these losses, and chooses to view them as a transfer payment among customers, the financial benefit usually recognized by utilities from detection and reduction of tampering is not recognized in this case. I discuss this issue in more detail on page 2-28 of my testimony.

PG&E also does not capture the inevitable increased revenue benefit from the improved accuracy from replacement and recalibration of meters. Induction

[11] "Theft of Service: Should Utilities Do More?", *Public Utilities Fortnightly*, September 15, 1992, page 21.

meters tend to run slightly slow over extended periods time. An AMI installation involves the removal and fresh calibration and/or replacement of all meters in the system. This process weeds out slower meters and will consistently produce a higher revenue stream. Again, this improvement in revenue would ordinarily be recognized as a benefit and used to justify AMI deployment by utilities under different regulatory formats.

This process eliminates random inequities that are inevitable with a population of meters in which some are slightly "slower" than others. Improved meter accuracy also results in a slight revenue increase that can be considered a cost savings to the utility or to ratepayers, depending on how those increased revenues are treated for ratemaking purposes. This benefit, like the reduced theft benefit, is mainly in the nature of increased equity or fairness among ratepayers.

The enhanced ability to respond more effectively to outages, and to reduce the duration of outages and, thus, reduce the corresponding lost energy sales revenue are other important contributors. Shorter service interruptions also constitute value to consumers and businesses that does not show in the utility business case but is significant to ratepayers. The improved customer service benefit of greater accuracy relative to bill proration may be difficult to quantify, but it nonetheless exists.

PG&E did not include in its business case the reduction in cost and improved service to customers of "off-cycle" meter readings during a month in which such readings are necessary. It claims that it now pro-rates the readings for apartments or homes changing occupants or owners.[12] Most utilities are required to provide actual meter readings in these cases, and they find that the savings from

[12]Exhibit PG&E-3, page 1-3, lines 24 & 25, and page 1-7, lines 9 to 11.

instant, remote off-cycle reads by an AMI systems are substantial compared to the high cost of special trip for a single meter reading.

PG&E comes close to justifying the procurement of the AMI systems based entirely upon operating cost benefits, without counting ratepayer benefits that do not benefit PG&E shareholders, and without relying on demand response benefits. I believe that PG&E's analysis was conservative, and that the business case did not capture a number of other benefits normally counted by other utilities. Were such other benefits to be included I believe that PG&E could clearly justify the AMI procurement on operating benefits alone, without respect to demand response. The PG&E plan also does not adequately identify and ensure the realization of many other benefits that the AMI system can provide to its customers, as noted previously. These benefits are important and the consumer deserves them.

Q: Can you offer more information on theft of service?

A: The installation of an AMI system provides a rare opportunity to discover theft of service and meter tampering, and to initiate aggressive revenue recovery and/or prosecution of offenders. This opportunity must be very thoughtfully developed so that the installers are both trained and motivated with personal incentives to seek out and report possible tamper incidents. Some significant portion of theft occurs through meter tampering. Still more theft is in "wiring around" meters, taps ahead of the meter, jumpers and bypasses that do not necessarily involve the meter. The installation work force must be trained to look for all of these. It is my understanding that, for ratemaking purposes, PG&E's theft losses are simply lumped together with other unaccounted-for losses. This may explain why PG&E appears to be paying less attention to this matter than would utilities that have financial incentives to minimize theft.

Most utilities recognize the economic benefit from revenue recovery and reduction in theft. Since it is in the ratepayers' interest to have PG&E mitigate and deter theft, I believe that the PUC should establish a means by which PG&E would have an economic stake in this issue, with both upside and downside potential.

E. <u>Ensuring that Benefits Are Realized</u>

Q: Do you have concerns about the implementation schedule proposed by PG&E?

A: The sensitivity of both project benefits and costs to schedule slips can be very large. PG&E admits to this being a very aggressive schedule. I recommend that PG&E be held to a high standard of performance of schedule completion by explicit and well defined milestones, and that missed milestones have substantial consequences borne by PG&E shareholders. The Commission should require that a detailed project milestone schedule be presented, with accompanying consequences for poor performance. Due to the complexity and extended schedule of the project, I recommend that DRA be authorized to hire an outside independent auditor to review the system status with the costs coming from, reimbursable accounts.

PG&E proposes to do the entire installation using a single installation contractor. There are arguments for and against using two or more contractors on a project of this size and duration. One strong argument for using two contractors, and commissioning the work in successive phases, is that the subsequent phases may be awarded in proportion to the demonstrated performance of each contractor.

Q: Are PG&E's plans for integrating the AMI investment into its operating system adequate to ensure that the expected benefits in customer service, billing, outage management, operations and maintenance and other areas are achieved?

A: Integration of AMI systems into legacy applications is always challenging, and will be for PG&E given the historic size of the project and the huge increase in the amount of data that must be collected, processed and stored. PG&E contracts with implementation contractors must have sufficient "teeth" to ensure timely and complete performance. PG&E's customers must not bear the risk of flawed performance by PG&E or its contractors, especially in light of PG&E's well-known difficulties with its other major software installations in recent years.[13] Further, PG&E should be required to audit the performance of its system on at least an annual basis, and should be required to report to the Commission on the degree to which the systems are meeting, falling short or surpassing projections. This recommendation is discussed next.

Q: Does PG&E demonstrate that it has a plan to periodically evaluate systems performance and to audit the expected benefits, and to take remedial action if expected benefits are not being obtained?

A: The periodic benchmarking of system performance and the follow-up to monitor whether intended benefits are realized are essential. I strongly recommend that PG&E be required to report quarterly to the Commission on the level of deployment of the overall systems, the originally expected benefits, the benefits actually being obtained, and any remedial actions needed to ensure that the proposed benefits are achieved. I have not seen any such plans in PG&E's application.

F. Automatic Water Meter Reading

Q: Should the systems be planned to permit automatic reading of water meters, as well as gas and electric meters?

A. PG&E's selected a PLC communication system for electric metering. This technology is not especially well suited for water metering in PG&E's territory.

[13] See Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Pacific Gas & Electric Company, I.03-01-012 ("PG&E Billing Investigation").

PG&E's proposed separate radio system by Hexagram for gas meter reading is very well suited for water metering and is currently in use by many water utilities around the United States. I have not looked at this in detail, but I expect that there would be a good overlap between the areas in which PG&E provides gas service and where there is municipal water service. Residential gas service is uncommon rural areas, and private wells are more likely to be the water source in these areas.

Q: Would it be feasible to require electric utilities to offer automated meter reading service to water utilities in their service territories? Should the Commission require that electric utilities' meter reading systems be capable of integration with the automatic reading of water meters?

A: While there are very few technical impediments to adding water metering to PG&E's selected RF system for gas meters, there may be other political or economic barriers. Such "joint metering" arrangements are surprisingly rare. There are many examples of combined electric, gas and water installations, but these are primarily by municipal utilities. The City of Colorado Springs in currently installing such a system. Yet historically, there has been surprisingly little "joint metering", where electric utilities do the water metering for a third party.

If history repeats itself, PG&E may find less interest by water companies in PG&E's reading of water meters than we might expect. Because the actual level of interest of most water utilities in having another utility read their meters has historically been so low (a joint EPRI/AWWA research project reported on this phenomenon[14]), it seems imprudent to risk distorting a utility's choice by imposing a requirement that any system be capable of integrating water metering. Experience thus far shows that the institutional issues are the drivers of success or failure. If California expects it can integrate the institutional interests and

[14] Joint Meter Reading – A Collaborative Approach, EPRI Final Report TR-112559, May 1999 by EMA Services, Plexus Research and Institute of Gas Technology. This report describes research sponsored by EPRI and the American Water Works.

operations of the water and electric utilities, then joint meter reading may be a good idea. Otherwise, maybe not.

G. Additional Observations

1. Level of Participation in Critical Peak Pricing Rate

PG&E indicates that approximately 3 percent of its customers now participate in its optional TOU rates, yet it expects that 22 percent of residential customers will opt in for a CPP rate.[15] This greater participation is apparently based upon the belief that a highly effective (and costly) marketing program is the key to recruiting this level of customer participation. Many TOU rate programs have suffered from a high level of disaffection and drop-out over extended time periods, a dynamic that could not be captured within the duration of the Statewide Pricing Pilot. If the average level of participation is no greater than the current TOU participation, the need for hourly data from all customers falls to a fraction of that otherwise needed, with a dramatic reduction in the data that needs to be acquired from the field, processed and stored.

While there are advantages to being able to capture hourly data from any customer anywhere, there may be more economical means of serving a customer population with low levels of TOU/CPP participation. The point of these comments is simply to highlight the fact that PG&E has specified its AMI system based upon assumptions that may or may not prove to be valid, with no off-ramps.

2. Load Control

The PLC system proposed by PG&E is well known and widely deployed in other utilities for its load control capabilities. PG&E apparently doesn't intend to make those capabilities part of its demand response portfolio, either in a traditional sense of utility-dispatched control of deferrable loads like pool pumps, irrigation

[15] A.04-06-024, Exhibit PG&E-3, Chapter 1B workpapers, page 1B-3

pumps, electric water heat, air conditioning cycling, etc. Nor is PG&E proposing in its AMI application to offer its customers a load control option of choosing to have certain loads disabled during critical peak price periods.[16] These capabilities are intrinsic to the proposed PLC system.

3. Service Disconnect/Reconnect Collars

PG&E indicated that it will install a disconnect collar at any meter where any single need to disconnect service to a customer arises, whether because of non-payment or because of a customer request. This procedure would apparently be followed even in cases where there was no reason to believe there will be a second need to disconnect following the initial reconnection. This concern is raised because of the very large proposed quantity (600,000) of devices that are relatively expensive, even though the price is considerably lower than I have seen in other recent utility procurements. I have not seen enough of the justification of these strategies and costs to conclude that this strategy and these costs are consistent with best prevailing practices.

III. CONCLUSION

PG&E has selected separate AMI systems for electric and gas which, each with a level of development and refinement typical of large-scale AMI deployments. These systems should be capable of providing the desired levels of functionality. The PG&E business case that justifies 89 percent[17] of the AMI system through operational benefits, quite apart from any demand response benefits, is well done, and is probably conservative. (That is, operational benefits have been estimated conservatively).

[16] I understand that a pilot air conditioning cycling program that would be marketed concurrently with CPP rates is being discussed in A.05-05-006, et al. for Central Valley customers. Depending on the success of this pilot, it could be expanded to enable more customers to easily respond to CPP rates.

[17] This percentage is about 81 percent using DRA's recommended discount rate.

Other aspects of PG&E's selection and justification are unnecessarily opaque. A number of areas that would typically be important contributors to the business case were not addressed by PG&E, apparently because they do not have financial impact on PG&E. Several of these do, however, have direct impact on individual consumers. PG&E would have been well advised to catalog and illuminate these consumer benefits as part of its presentation to the Commission. Among these benefits are: improved equity by reduction in theft of service, improved equity by reducing metering errors, improved equity by more rapid and widespread disconnection of no-pay customers, reduced intrusion from meter reader on customer's property, more accurate meter readings, fewer customer complaints about billing errors, fewer service outages (due to better distribution system management), more rapid recovery from outages, improved power quality (remote tracking of end of line voltage), more rapid resolution of billing complaints (read while you wait), accurate and readily available off-cycle readings (rather than estimates) for property transfers.

With respect to open standards issues, there are at least two important interfaces that are essentially "open" that PG&E has neither identified nor exploited. These open interfaces allow other companies to participate in offering products to PG&E or to its customers. This shortcoming is easily remedied by addressing the specific interfaces of the disconnect collar, by ensuring that these interfaces are non-proprietary, and by a commitment to support a variety of non-proprietary customer response communication approaches.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 3

CRITICAL PEAK PRICING RATE DESIGN

WITNESS: SCARLETT LIANG-UEJIO

I. INTRODUCTION

This chapter presents the Division of Ratepayer Advocates' ("DRA") analysis and recommendations on PG&E's proposed critical peak pricing ("CPP") rate design for residential customers. DRA addresses only the residential CPP rate design because of the specific issues related to tier rates and the rate protection provided by Assembly Bill ("AB") 1X. DRA does not oppose PG&E's proposed CPP rate design for small commercial and industrial ("C&I") customers.

In Chapter 11 of this testimony, DRA uses its alternate CPP rates for residential customers, as shown in this chapter, as one of the inputs for the calculation of the demand response benefits. Because CPP rate is one of the inputs for the calculations of demand response benefits, CPP rate design would have a direct impact on the advanced metering infrastructure ("AMI") business case.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends the following:

1. The Commission should adopt DRA's proposal for a new CPP rate option that is subject to usage above 130 percent of baseline and based on a time-of-use ("TOU") rate structure, in addition to existing flat and TOU rate options.

2. In-home automated load control and information feedback should be integrated with the CPP program to enhance demand response. The Commission should address load control and related communications

> expeditiously and implement such program as soon as possible.

DRA's rate design assumes that the AB 1X protections on usage below 130 percent of baseline cannot be voluntarily waived by the customer.

III. DISCUSSION

A. CPP Objectives

There is no lack of Commission decisions and rulings, studies, and reports that emphasize the importance and need for demand response in California. Indeed, the initiative for AMI deployment, as stated in many of the Commission's rulings, was to achieve demand response. In the ACR for the AMI business case analysis, the Commission stated:

> "(t)he purpose of this proceeding is to increase the level of demand response, in particular price responsive demand, 'as a resource to enhance electric system reliability, reduce power purchase and individual customer costs, and protect the environment.' "[18]

Yet actualizing the demand response potential in the residential sector poses significant challenges. DRA accepts PG&E's recommendation that any dynamic rate be introduced on a voluntary basis at least through the duration of the AMI rollout. However, to achieve participation in the program on a voluntary basis that will be sustainable; the rate presented to customers must enable sufficient energy and bill savings to generate customer interest. Customers should also be given the tools and equipment required to automate their responses to such rates. Otherwise, the value of the time expended by customers to effectively use such rate options may be greater than the bill savings.

Fortunately, an opportunity exists in the rate design that could be used to generate customer interest amongst the larger residential energy users. Owing to AB 1X limitations and existing revenue allocation policy, such customers

[18] Join Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, p.1.

currently face a tier structure that is very highly inverted. For PG&E, such tiers are even part of its TOU rate, and they somewhat mute the TOU information in the tariff. It is true that such tiers produce a significant conservation incentive. However, the current Schedule E-1 tier 5 rate of $0.33/ kWh probably vastly exceeds the value of conserving energy.

No Commission decision or ruling exists that indicates that the current five-tier rate structure must be preserved in CPP rate design for usage above 130 percent of baseline. Therefore, the tiers above Tier 2 could be replaced with TOU periods. The price differentials between TOU periods could be as high as, or higher than, those that exist between the existing inverted tiers. This would send a price signal that has the potential of invoking a relatively large demand response. Economists agree that TOU rates are far more efficient than the current inverted tier rates. As parties indicated in the CPP Phase I proceeding,[19] TOU rates encourage long-term capital investment on energy management technology. Such capital investments make the demand response sustainable.

DRA's proposed CPP rate design assumes that the AB 1X rate protections in tiers 1 and 2 cannot be voluntarily waived by the customer. Therefore, unlike PG&E, it applies no CPP price signals to those tiers. By limiting such signals to the over 130 percent of baseline usage, a significant conservation incentive is retained within the rate design. But coupled with that is a strong demand response incentive in the usage above 130 percent of baseline.[20]

A rate design that replaces the upper tiers with TOU periods also has the advantage of being fairer to large customers with relatively flat load factors. Some are middle-income customers with large families that have little or no protection

[19] D.05-04-053, p. 40-41.

[20] DRA acknowledges that limiting dynamic and TOU price information to over 130 percent of baseline usage tends to limit their effect because only 33 percent of residential kWh usage is above this level. But, DRA is working on the assumption that AB 1X prohibits applying TOU or CPP price signals to usage below 130 percent of baseline for those customers not currently on TOU rates.

under current rate designs. A case could be made for completely eliminating the current five-tier rate structure in favor of a TOU rate design, without tiers. However, DRA believes that this issue should be reserved for a future proceeding after the AMI rollout has been completed and a bill impact analysis can be done. At that point, more information would be available about the participation and demand reductions that are achievable when the CPP or TOU rate is voluntary.

In summary, the two major features of DRA's CPP rate design policy are to link CPP with a TOU rate and to provide means for automating the customer's response. In the sections below, DRA presents evidence to support these features from the United States Government Accountability Office ("GAO"), the Statewide Pricing Pilot ("SPP"), and from a residential CPP program instituted by Gulf Power.

B. Information from the United States Government Accountability Office

According to the a report by the GAO in August 2004, entitled "Electricity Markets, Consumers Could Benefit from Demand Programs, but Challenges Remain," "(d)emand response programs face three main barriers to their introduction and expansion: (1) regulations that shield customers from short-term price fluctuations, (2) the absence of needed equipment installed at customer's sites, and (3) customers' limited awareness of programs and their potential benefits."[21] DRA's CPP proposal is designed to minimize these barriers by providing a rate design that reflects price fluctuations during major time periods, and by encouraging the use of equipment on the customer's site that will automate demand responses to rates.

[21] p.31.

C. Statewide Pricing Pilot and PG&E's Current Experimental Residential CPP Service

The rate design being used in the current SPP is more than a simple CPP rate that would be applied on top of any existing rate structure. It overlays a CPP super peak, peak, and off peak charges over the existing Schedule E-1 tier rates. Therefore, it has a combination of both TOU and tier structures.

The SPP also included a separate treatment for TOU. It concluded that "that there will remain a significant amount of demand response that can be achieved through TOU and dynamic pricing."[22] In its testimony on Demand Response Policy, PG&E states, "PG&E attaches significant weight to the results of the SPP, which systematically analyzed combinations of TOU and CPP rate design options."[23] However, unlike the SPP's CPP rate, PG&E proposed a rate design that separately adds or subtracts a CPP rate or non-CPP credit to its current non-TOU and TOU rates, both of which have tiers.[24]

D. Gulf Power's CPP Experience

1. Gulf Power's CPP

Two years prior to California's SPP, Gulf Power Company, in Pensacola, Florida, launched a voluntary residential CPP program called "GoodCents SELECT" ("Gulf Power CPP") in March of 2001. The Gulf Power CPP was initially designed for its 200,000 single family customers and is now moving into the multi-family segment this year. The Gulf Power program is the only CPP rate currently offered in the country.

The Gulf Power CPP "is a residential advanced energy management system that gives customers control over their energy purchases by allowing them to

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[22] P.12 of "Impact Evaluation of California Statewide Pricing Pilot" prepared by Charles River Associate on March 16, 2005.

[23] Lines 31 to 32 on page 1-3 in PG&E-4, Chapter 1.

[24] Lines 10 to 13 on page 1-4.

program their central heating and cooling system, electric water heater and their pool pump to automatically respond to varying prices."[25] The Gulf Power CPP is based on a TOU rate structure with four periods: critical, high, medium, and low. Table 3-1 shows some highlights of the Gulf Power CPP.

The primary objectives of the Gulf Power CPP are demand response (peak shaving and valley filling), customer satisfaction, and regulatory compliance. Gulf Power recognized and designed its CPP to overcome three challenges:

1. The "total costs" or "total effort" of responding to price changes is much more than the price difference.

2. Lowering the incremental "cost" or "effort" of responding should increase the amount of price response

3. An in-home, customer-programmed, automated energy management system reduces this "costs/effort" that customers must bear.

Gulf Power's approach uses rate and equipment (a gateway and smart thermostat) to provide benefits for both customers and its system (win-win). It limits CPP events to 87 hours annually and event duration to between 1 to 3 hours. Table 3-2 shows the historical CPP events from 2002 to 2005. Because of the pre-programmed in-home automated energy management system, only a one hour advanced CPP event notification is required. It eliminates the need for a day-ahead CPP event forecast and notification. It also eliminates phone calls to notify customers because the smart thermostat has an indicator for CPP events.

2. <u>Gulf Power's CPP Results</u>

In 2005, about four years into the introduction of its CPP program, Gulf Power has about 7,200 participants (about 4 percent), tripling the number of participants in 2002. In August 2005, it achieved 14 MW (or 2 kW per

[25] Page 4 of the PowerPoint Presentation to DRA by Gulf Power on November 1, 2005.

participant) of average peak load reduction. Customers save up to 15 percent annually and use 3.8 percent less energy.

Gulf Power projects that its CPP participation will grow about 3,000 to 4,000 per year. Today, Gulf Power CPP is available to multi-family customers, and its total residential population is about 350,000. It has a goal of reaching a total of 40,000 (12 percent) participants to achieve an 80 MW load reduction in the future.

4. Lessons for California

The studies and results of the SPP in California are valuable, especially the price elasticity studies. However, unlike the SPP, the Gulf Power CPP is not a pilot program. It has real customer participation and price response experience from a voluntary CPP program in the residential segment.

Its innovative rate design coupled with in-home automated energy management system resolves several big issues that customers brought up in the CPP Phase I proceeding for large C&I customers[26]. In that proceeding, the Commission attempted to implement a default CPP rate and received strong opposition from all parties except for the utilities and DRA. One of the big issues was that the CPP event would be forecasted day ahead, and parties were concerned about the potential for wrong forecasts, resulting in the utilities calling unnecessary CPP events. One hour advance notification, while not completely eliminating the possibility of unnecessary CPP events, substantially reduces the forecast error.

Another issue was the large C&I customers' concern with the duration of CPP events, and the potential for adverse bill impacts because of customers inability to respond to CPP events due to the lack of automated energy management systems. These would also be the important issues for residential

[26] A.05-01-016 et all.

customers. The GAO report shows that the "absence of needed equipment installed in customer's site" is one of the barriers for the introduction of CPP. Gulf Power CPP has addressed these challenges. Gulf Power CPP limits a CPP event to no more than three hours, and this reduces the cost and effort for customers to respond.

As shown in Table 3-2, Gulf Power had a total of 23 CPP events from January 2002 to July 2005. Only one CPP event was two hours, and all of the others were only one hour. Reducing load for one hour would be much more appealing to customers than five-hour events, even with potential customer overrides.

E. PG&E's Proposed CPP Rate Design for Residential Customers

In its testimony, PG&E recommends offering its proposed CPP rates to customers on a voluntary, opt-in basis over the course of the AMI project deployment period (2006 to 2010). DRA's analysis focuses only on residential CPP rate design.

For residential customers, PG&E proposed a CPP charge of $0.60/kWh. The CPP charge will be overlaid on top of the current five-tier rates. In other words, the $.60/kWh rate would be added to each rate in the first five tiers. In order to maintain revenue neutrality, PG&E proposes a credit of $0.03/kWh for non-CPP period usage. PG&E proposes an additional participation credit of 1.0 cents per kWh that would apply to all upper-tier usage (Tier 3 and above).

1. PG&E's Rate Design Objective vs. CPP Objectives

PG&E's overlay CPP rate design policy emphasizes the following goals: 1) rate design flexibility while preserving revenue neutrality, 2) preserving the existing tier structure, and 3) providing customer choices.[27] PG&E is also

[27] Lines 29 to 31, p.1-1, PG&E-6, Chapter 1

concerned about customer participation and thus proposes first year bill protection. While PG&E has made a good faith effort to design a CPP rate that will be attractive enough to customers to obtain a certain level of participation, its approach does not address the barriers articulated by the United States GAO.

First, the existing non-CPP inverted tier rate sends an inaccurate price signal. Under PG&E's proposal, customers on flat rates would receive a price signal only on the 12 to 15 days per year when CPP events are called, which is less than 1 percent of the total hours. It is true that PG&E's CPP rate could be overlaid on an existing TOU rate. However, PG&E's current TOU rate has the deficiency of fairly large surcharges that are not time-differentiated that mute the overall price signal. Furthermore, PG&E's $.03/kWh credit would even be applied to the non-CPP summer peak hours. Having a clear incentive to reduce or shift load on non-CPP days is important. It encourages customer demand response to become a more routine activity, which may help prevent CPP events in the first place. Also, limiting the price signal to 12 or 15 days leaves the utility with no recourse in the event of a critical peak situation after the maximum number of CPP events is called.

Second, there are no provisions for automating the customer's response. This may work against long-term sustained participation. Load control was one of the five schedules (Schedule 5) outlined under PG&E's Request for Proposal for the potential AMI system. This schedule included smart thermostats and other in-home equipment. PG&E received proposals from [redacted]. However, PG&E omitted this component from its final vendor selection process and business case.

2. Compliance with AB 1X

Because of its overlay CPP rate/non-CPP credit structure, PG&E's proposed CPP rate design augments rates in all tiers including Tier 1 and 2. Depending on their energy usage during a CPP event, Tiers 1 and 2 customers may pay different and potentially higher rates than their current Tiers 1 and 2 flat rates on a net basis. Thus PG&E appears to have assumed that the rate protection provisions of AB 1X can be waived by the customer.

Table 3-4 shows the illustrative bill impacts of PG&E's rate design for a Tier 2 customer with usage up to 130 percent of baseline allowance. For example, if this customer used 5 percent or more of the total energy during the CPP hours and took no action to reduce or shift load, the customer would see a bill increase of $0.75 or more that month.

PG&E designed its CPP rate/non-CPP credit based on the assumption that 4.75 percent of total residential class customer participant usage would be during the CPP events. If Tier 1 and 2 customers' CPP usages were higher than the average of 4.75 percent, they would see an increase in the total bill. However, because PG&E also proposed first-year bill protection for each customer's summer season, the potential bill impacts would only affect customers in the second year and beyond.

F. <u>DRA's CPP Rate Design</u>

As discussed above, DRA's CPP objectives are to send the correct price signal, achieve peak load reduction, and provide customer savings. It should be a win-win for both the system and customers. The CPP rate design should follow these principles and comply with the current law. DRA proposes to use Gulf Power CPP as a framework for PG&E's new CPP rates. To comply with AB 1X, DRA proposes CPP rate for usage above 130 percent of baseline. Similar to the Gulf Power CPP, it is TOU based.

In this rate design chapter, DRA is not proposing a specific technology or in-home automated energy management system. Rather, as a policy, in-home load control and information feedback should be integrated with the CPP program on a cost effective basis. In Chapter 2 DRA discusses the alternatives that the Commission can consider.

1. Schedule E-SS, Energy SmartSave Program

As shown in Table 3-5, DRA developed a set of CPP/TOU rates for PG&E's new voluntary CPP program that DRA calls the "Energy SmartSave Program" (Schedule E-SS). This name would work well with PG&E's deployment of AMI meters (commonly known as "smart meters").

2. Rate Design Assumptions

DRA developed the illustrative CPP/TOU rates based on PG&E's tier rates under the Schedule E-1 as of January 1, 2006 on a revenue neutral basis.[28] DRA also used both January 1, 2006 and the new CPP rates for its estimates of demand response benefits in Chapter 11. DRA developed two rate scenarios:

1. The Gulf Power's CPP rates are used as a framework against the TOU ratios proposed by PG&E in its last general rate case.[29] The on-peak rate is set residually.
2. A CPP rate based on the capacity value of $52/kW-yr is divided by 87 hours, and added to the on-peak charge in the first scenario. The off-peak rate is set residually.

The second scenario is DRA's recommended rate design where the incentives are cost based. The first scenario is an alternate, which contains higher incentives to obtain greater demand response. The mid-peak rate (same for both scenarios) is set at the Tier 3 level. DRA assumes the same hours for on-peak, mid-peak, and off-peak as currently defined in PG&E's TOU-8 tariff. The CPP is limited to 87 hours annually (1 percent of total hours).

3. Daily Baseline Allowance Adjustment with a True-up Mechanism

The new AMI system will collect hourly customer usage information. DRA's rate design would apply TOU and CPP prices to a percentage of each

[28] Pending Commission's approval of PG&E's Annual Electric True-up Advice Letter No. 2706-E-A (filed on December 30, 2005).

[29] A.04-06-024, pages 1-14 and 1-11 in PG&E-4

hour's usage. It would be simplest to base this percentage on the ratio of usage above and below 130 percent of baseline for the entire month. Tier 1 and 2 rates would be proportionally applied to that percentage of the hour's usage that has been allocated to the below 130 percent of baseline rate category.

The problem with using monthly percentages is that they could mute the CPP price signal in a given hour. For example, a customer could reduce his or her usage below 130 percent of baseline during a CPP hour and theoretically avoid the CPP rate altogether. Yet some of the customer's usage during that hour still might be allocated to the above 130 percent of baseline rate category owing to the use of monthly percentages. Indeed, a customer would have to reduce his or her usage to below 130 percent of baseline during every CPP hour to solve this problem. But the problem would still remain for all the TOU rates, and could only be mitigated by the customer consuming below 130 percent of baseline during every hour of the month.

The best way to overcome this challenge is to perform the baseline to non-baseline allocation on the basis of daily baseline allowances. In fact, the tariffs already provide such daily allowances for the purpose of bill prorating in off-cycle meter reads. Yet, a good argument can be made that the baseline protections should be extended to the customer on a monthly basis whenever possible. That is because a customer may not use all of his or her below 130 percent of baseline allowances on a given day. Thus the customer may lose some of the protection he or she now receives because the allowances currently are applied to monthly usage.

To overcome the challenge of the AB 1X limitation, DRA recommends the use of a daily baseline allowance *adjustment* to calculate the amount of usage subject to Tiers 1 and 2; and to the CPP/TOU rates for the critical peak, on-peak, mid-peak, and off-peak periods.[30] If, the customer uses less than 130 percent of

[30] The daily allowance would then need to be allocated to the four CPP/TOU periods.

the daily baseline allowance on some days, the baseline allowance for the remaining days would increase accordingly. PG&E can either adjust the CPP/TOU usages for these days or give a one-time adjustment in the monthly bill.

DRA recognizes that this mechanism is not ideal and adds some complications to the CPP program. DRA, however, wants to maintain the AB 1X rate protection as they have been traditionally applied to bills.

4. Bill Impacts

DRA analyzes bill impacts on two different levels: average and individual customers. Because DRA's CPP rate design is revenue neutral based on Schedule E-1 rates, there should be no bill impacts to the average customers assuming no change in their load profiles. However, customers in different climate zones within PG&E's territory would pay slightly different average rates due to their load profiles. A comparison of average rates and bill impacts by climate zones is provided in Table 3-6.

Due to the lack of customer historical usage data for the CPP and three TOU periods, DRA was not able to run a bill analysis to determine the distribution of various bill impacts. However, such an analysis is more critical for default rate changes. Given CPP will be introduced on a voluntary opt-in basis, DRA performed a simplified bill analysis similar to PG&E's based on the usage information available for Zone R (inland hot areas) in PG&E's 2003 Class Load Research Population ("CLRP") model.[31]

For each climate zone, Table 2-7 shows the bill impacts for hypothetical customers who consume at 300 percent (Tier 4) and at 400 percent (Tier 5) of baseline levels, and reduce their CPP loads by 14 percent and 28 percent. These load reductions are equal to the average load reduction predicted by the SPP model and double that reduction. These scenarios assume that the average non-

[31] PG&E's responses to DRA's DR No. 20 and The Utility Reform Network's ("TURN") DR. No. 4, Q.19.

CPP on-peak load reduction were one third of the CPP load reduction. Since this analysis uses average load shapes and average SPP-based load reductions for those climate zones, it probably underestimates the bill reductions for tier 4 and 5 customers. Tier 4 and 5 customers are likely to have lower load factors and thus the potential for larger load reductions than the average customer in those climate zones. Table 2-7 tends to suggest that DRA's CPP rate design most favors large residential customers. These customers, however, are the ones with lower load factors and whose higher bills justify the kind of home energy management equipment that DRA recommends be coupled with this rate design.

5. "Free Ridership"

"Free ridership" refers to the structural revenue shortfall that potentially exists in a voluntary rate option. That is, because the new rate structure is revenue neutral based on the old rate design; bills for customers with class average load profiles would not change. But not all customers have average load profiles. In theory, half of the customers in a rate group have better or worse than the average load profiles. Logically, customers with better load profiles would be winners even without changing their loads. Therefore, they would opt into the new CPP rate and create a structural revenue shortfall. The other group of customers would stay with the old flat rate. The winners who opt into the new CPP rate would be the so called "free riders." This potential exists with any voluntary CPP rate. It might especially be a problem with DRA's rate design because it is inherently fairer to the larger coastal high load factor customers.

If demand response is a goal, one would want the new CPP program to attract the lower load factor customers in the Central Valley with high air conditioning loads. Of course, the only way to make sure such customers have TOU or CPP rates is to make such rates mandatory. Learning from Gulf Power's CPP rate design and its experience, DRA believes that the structural revenue shortfall could be minimized by coupling the CPP rate with in-home automation equipment. Such equipment encourages customers with high air conditioning use to opt into this rate. Also, TOU rates encourage long-term capital investments for energy efficiency, load control, and solar energy.

In its alternate, DRA also includes an energy management ("ES") service fee of $3.50/mo. per participant to deter potential free riders. This charge is equivalent to the meter charge in PG&E's current voluntary CPP tariff (Schedule E-3) under the SPP of $3.45 per month ($0.11532 per day), which is less than Gulf Power's CPP participation charge of $4.95. The design of the ES service fee is not revenue neutral. The revenues from ES service fee could be used to offset the costs of providing technical or energy management assistance to the participants.[32] However, DRA proposes no monthly charge under its recommended CPP rate design.

Finally, there is also an issue of just how concerned about revenue neutrality the Commission should be. Innovative CPP rates should be based on the fundamental principle of sending the right signal. Gulf Power believes that the value of sustainable and accountable demand response, and the cost savings from the unserved energy, exceeds the revenue shortfall in the long run.[33]

6. CPP Rate Design for CARE Customers

DRA believes that a CPP rate should be available to CARE customers. Unfortunately, PG&E's CRLP data does not have CARE usage information. Therefore, DRA was unable to develop CARE CPP rates. The Commission should direct PG&E to develop such a rate during a compliance phase after its Phase 2 decision is issued. DRA can work with PG&E to develop CPP rates for CARE customers (Schedule E-SS ("CARE")).

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[32] Gulf Power's uses the revenues from the CPP participation charge plus a small adder in the on-peak rate as a funding source for about 60 percent of the equipment (gateway and smart thermostat) costs. The rest comes from energy efficiency program funding.

[33] Based on a discussion between Gulf Power and DRA on Gulf Power's CPP program in November, 2005.

III. CONCLUSION

DRA proposes a CPP/TOU rate that protects usage below 130 percent of baseline, while simultaneously providing the incentive for demand reduction. DRA's CPP rate also simplifies the rate structure by eliminating tiers above 130 percent of baseline usage. Usage above 130 percent of baseline would be billed according to the time period it was used. DRA recommends that this practical and reasonable CPP rate be adopted for residential customers. DRA's illustrative CPP rates are shown in Table 3-5.

DRA is concerned that PG&E's proposed new CPP rate design would potentially affect rates for customers' usage below 130 percent of baseline, and thus may not guarantee the protections from AB 1X. In addition, its proposed credit for the non-CPP hours (including regular peak) sends incorrect price signals, which contradicts the objectives of demand response. Therefore, the Commission should reject PG&E's proposal.

Table 3-1

Highlights of Gulf Power CPP Program

Key Element	Feature	Notes
Applicability	1. Residential single family home (< 200 Amp service) 2. Voluntary opt-in	1. Gulf Power will consider moving into multi-family segment this year
Monthly Charge	$4.95/mo.	1. Customers save by acting and reacting 2. Customers unwilling to change will not participate
CPP Event & Notification	1. Maximum 87 hours annually (about 75% - summer, 25% winter) 2. Maximum 1-3 hour per CPP event 3. One hour-ahead notification (through Indicator Light on the Thermostat)	
CPP Rates ($/kWh)	(Standard Residential Rate – 7.7 cents/kWh) Low 5.4 cents Medium 6.7 cents High 11.2 cents Critical 32.1 cents (2.87:1 CPP:TOU) Percent of Annual Hours Low 28% Medium 59% L&M 87% High 12% CPP 1%	
CPP Customers Benefits	1. Save up to 15% or more off annual bill 2. Free surge protection 3. Automatic control of energy usage 4. Free installation 5. Lower price 87% of the time 6. Medium Tier Default Rate when system malfunctions.	1. Choice 2. Control 3. Savings
Program Hardware Requirement	1. Programmable smart thermostat (energy management system) 2. Communication gateway	1. The thermostat controls central cooling and heating system, electric water heater, and pool pump. 2. The gateway is attached to the meter outside. It has two-way communication.

Key Point for the Program Design	- The "full cost" or "total effort" of responding to price changes is much more than the price difference: 1. Customers must act in order to respond 2. Customers must understand the economics 3. The actions require time and effort - Lowering the incremental "cost" or "effort" of responding should increase the amount of price response. - An in-home, customer programmed automated energy management system reduces this "cost/effort" that customers must bear.	

Table 3-2

Gulf Power Historical CPP Events

Year	Date	Day of Week	Start Time (Hour beginning in Central Time – Standard or Daylight)	Hours	Number of Customers at Month-End
2002	**1/3**	**Thu**	**0800**	**1**	**2230**
	1/4	**Fri**	**0900**	**1**	**2230**
	1/8	**Tue**	**0600**	**1**	**2230**
	2/27	**Wed**	**0800**	**1**	**2274**
	2/28	**Thu**	**0700**	**1**	**2274**
	3/4	**Mon**	**0700**	**1**	**2316**
	3/5	**Tue**	**0700**	**1**	**2316**
	7/11	**Thu**	**1500**	**1**	**2738**
	7/17	**Wed**	**1600**	**1**	**2738**
	7/18	**Thu**	**1400**	**2**	**2738**
	7/19	**Fri**	**1600**	**1**	**2738**
2003	**1/17**	**Fri**	**0700**	**1**	**3166**
	1/24	**Fri**	**0700**	**1**	**3166**
	12/18	**Thu**	**0600**	**1**	**4244**
2004	**1/7**	**Wed**	**0600**	**1**	**4315**
	1/8	**Thu**	**0600**	**1**	**4315**
	1/21	**Wed**	**0600**	**1**	**4315**
	7/23	**Fri**	**1600**	**1**	**5272**
	8/4	**Wed**	**1600**	**1**	**5536**
	12/15	**Wed**	**0600**	**1**	**5722**
	12/16	**Thu**	**0600**	**1**	**5722**
2005	**7/26**	**Tue**	**1500**	**1**	**6226**

Table 3-3

Results of Gulf Power's GoodCents SELECT CPP Program

Subject	**Description**	**Notes**
Program Start Date	March, 2001	
Participation	2002: 2,740 2003: 4,250 2004: 5,730 2005: 7,200 (3.6 %)	Residential single family customers: 200,000 Total Res.: 350,000
Load Reductions	Feb. 2005 – 2 CPP Days (2 hrs.) Avg. Peak kW reduction – 18.5 MW Aug. 2005 – 2 Critical Days (3 hrs.) Avg. Peak kW reduction – 14 MW Over 2 kW per participant per CPP event Avg. 3.8 % less energy.	

Table 3-4

Illustrative Bill Impact for a Tier 2 Customer 1/

Assumed Usage (kWh)			CPP Charges and Credits			Projected Bill Changes		
CPP Use Percent	CPP kWh	Other kWh	CPP Charge	CPP Credit	Part. Credit	w/no CPP Reduction	with 25% Reduction	Percent Savings
3.0%	15	485	$9.00	-$14.55	$0.00	-$5.55	-$7.80	13.2%
4.0%	20	480	$12.00	-$14.40	$0.00	-$2.40	-$5.40	9.1%
5.0%	25	475	$15.00	-$14.25	$0.00	$0.75	-$3.00	5.1%
6.0%	30	470	$18.00	-$14.10	$0.00	$3.90	-$0.60	1.0%

1/ Assuming 500 kWh of monthly usage at 130 percent of baseline allowance.

Table 3-5

Current Default and DRA's Proposed CPP Rates

Default		Voluntary CPP			
Schedule E-1	**1/1/06 Rates** 1/	**Schedule E-SS**	**% of Hours**	**CPP Rates**	
	($/kWh)			($/kWh)	
Up to 130% BL:		**Up to 130% BL:**		(Alternate)	(recommended)
Tier 1	$0.11430	**Tier 1**	100%	$0.11430	$0.11430
Tier 2	$0.12989	**Tier 2**	100%	$0.12989	$0.12989
		Above 130% BL:			
Total Tier 1 & 2	$0.11690	**Summer**			
		CPP	1%	$1.50	$1.10
Above 130% BL:		**On-Peak**	8%	$0.49542	$0.49630
Tier 3	$0.21314	**Mid-Peak**	10%	$0.21314	$0.21314
Tier 4	$0.29007	**Off-Peak**	31%	$0.14513	$0.16049
Tier 5	$0.33039		50%		
		Winter			
Total Tier 3-5	$0.25465	**On-Peak**	9%	$0.36416	$0.36416
		Off-Peak	41%	$0.14513	$0.16049
			50%		
Total Tier 1-5	$0.15386	**EM Service Fees**	($/mo.)	$3.50	

Table 3-6

Average Bill Impacts for Different Climate Zones

(DRA's Recommended CPP)

Zones		Average Total Rates Current	Average Total Rates CPP	Average Monthly Bill 1/ Current	Average Monthly Bill 1/ CPP	Net Change $	Net Change %
Zone R	Mtn/Des	0.15993	0.16238	$153.08	$155.43	$2.35	1.5%
Zone S	Valley	0.15628	0.15798	$128.46	$129.85	$1.40	1.1%
Zone T	Coastal	0.14152	0.14138	$49.44	$49.39	-$0.05	-0.1%
Zone X	Hill	0.15253	0.15114	$83.40	$82.64	-$0.76	-0.9%
All Zones		0.15386	0.15386	$95.34	$95.34	$0.00	0.0%

(DRA's Alternate CPP)

Zones		Average Total Rates Current	Average Total Rates CPP	Average Monthly Bill 1/ Current	Average Monthly Bill 1/ CPP	Net Change $	Net Change percent
Zone R	Mtn/Des	0.15993	0.16327	$153.08	$156.28	$3.20	2.1%
Zone S	Valley	0.15628	0.15862	$128.46	$130.38	$1.93	1.5%
Zone T	Coastal	0.14152	0.14044	$49.44	$49.06	-$0.38	-0.8%
Zone X	Hill	0.15253	0.15087	$83.40	$82.49	-$0.91	-1.1%
All Zones		0.15386	0.15386	$95.34	$95.34	$0.00	0.0%

1/ Assuming no change in usage and
not include the EM Service Fee.

Table 3-7

Illustrative Individual Bill Impacts

Zone R (Tier 4)								
	Load Reduction		Current		DRA's Recommended CPP			
Scenarios	CPP	On-Peak	Total kWh	Total Bill	Total kWh		Total Bill 1/	
No Reduction	0%	0%	1,575	$311.08	1,575	0.0%	$322.8	3.8%
SPP Model	-13%	-4%	1,575	$311.08	1,554	-1.3%	$306.6	-1.5%
SPP Model x 2	-27%	-9%	1,575	$311.08	1,533	-2.7%	$290.3	-6.7%
Zone R (Tier 5)								
No Reduction	0%	0%	2,100	$484.54	2,100	0.0%	$465.4	-3.9%
SPP Model	-13%	-4%	2,100	$484.54	2,072	-1.3%	$443.7	-8.4%
SPP Model x 2	-27%	-9%	2,100	$484.54	2,043	-2.7%	$422.0	-12.9%
Zone S (Tier 4)								
No Reduction	0%	0%	1,422	$280.86	1,422	0.0%	$291.7	3.8%
SPP Model	-13%	-4%	1,422	$280.86	1,404	-1.3%	$277.0	-1.4%
SPP Model x 2	-26%	-9%	1,422	$280.86	1,385	-2.6%	$262.4	-6.6%
Zone S (Tier 5)								
No Reduction	0%	0%	1,896	$437.47	1,896	0.0%	$420.5	-3.9%
SPP Model	-13%	-4%	1,896	$437.47	1,871	-1.3%	$401.0	-8.3%
SPP Model x 2	-26%	-9%	1,896	$437.47	1,847	-2.6%	$381.5	-12.8%

1/ Assuming no change in usage.

SECTION II.A.

DRA'S ANALYSIS OF PG&E'S AMI BUSINESS CASE

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 4

SUMMARY OF THE COSTS AND BENEFITS TO DEPLY AMI
WITNESS: ANTHONY FEST

I. INTRODUCTION AND SUMMARY

This chapter summarizes DRA's computations of costs and benefits for PG&E's proposed AMI project. The analysis uses PG&E's present-value calculation model, with some changes in inputs and parameters.

DRA's analysis modifies some of PG&E's cost and benefit estimates, as explained in Chapters 7 through 11. Other inputs are the same as PG&E's, and DRA's analysis uses most of the same parameters (for example, tax rates and depreciation tables) as PG&E. However, DRA's analysis uses a discount rate (Weighted Average Cost of Capital) of 8.79 percent, where PG&E used 7.60 percent.

Table 5-1 presents DRA's estimates of the Present Values of Revenue Requirements ("PVRRs") for the costs and benefits of PG&E's AMI program, and compares them to PG&E's estimates. Row 6 ("Meter Operations") of Table 5-1 reflects DRA's estimate of theft detection and meter accuracy benefits of $92.8 million annually after a ramp-up period (PVRR of $758.6 million). In Row 9 ("other") of Table 5-1, DRA adds benefits from voltage reduction (with a PVRR of $100 million), as well as transmission and distribution benefits accruing from improved grid design efficiency and outage detection (with a PVRR of $48.2 million). These additional benefits are discussed in Chapters 10 and 12 of DRA's testimony.

DRA's demand response benefits are not included in the table. They range from $89 million to $309 million depending on the assumptions used. They are described in Chapter 11 of DRA's testimony.

TABLE 5-1

AMI COSTS AND BENEFITS

	PVRR of COSTS	PG&E	DRA
1	Total Deployment	1,898,430	1,670,156
2	Total O&M	366,411	329,083
	Grand Total	2,264,840	1,999,240
	PVRR of BENEFITS		
	Operational Savings		
1	Meter Reading	1,074,361	929,626
2	Employee Related	218,545	192,018
3	Interval Metering	75,316	66,245
4	Outage Detection	127,424	113,144
5	Billing Cash Flow	65,198	57,777
6	Meter Operations	110,163	855,645
7	Remote Electric Shut-off	101,987	89,923
8	Capital Savings	40,020	36,300
9	Other	48,060	191,618
	Subtotal	1,861,074	2,532,297
	Customer Services		
10	Call Volumes	39,930	35,000
11	Avoided Dispatch	61,009	53,481
12	Improved Billing Accuracy	62,167	54,495
	Subtotal	163,106	142,976
	Grand Total	2,024,180	2,675,273

SECTION II.B.

DRA'S ANALYSIS OF AMI COSTS AND BENEFITS

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 5

METER, MODULE, NETWORK, AND AMI OPERATIONS COSTS
WITNESS: SCARLETT LIANG-UEJIO

I. INTRODUCTION

This chapter presents the Division of Ratepayer Advocates ("DRA") analysis of Pacific Gas and Electric Company's ("PG&E") estimated costs of [redacted] million[34] for 1) meters and modules, 2) network materials, and 3) AMI operations for all electric and gas customers for 2006 to 2010. PG&E's estimated costs reflect an increase of [redacted] million from its original estimate filed on June 15, 2005 ("June filing") and exclude the pre-deployment costs of [redacted] million as shown in its Amended Application filed on October 13, 2005 ("October filing").[35]

II. SUMMARY OF CONCLUSION AND RECOMMENDATIONS

In summary, DRA finds PG&E's supplemental testimony, filed with its amended application on October 13, 2005 very confusing, and the increased costs are difficult to analyze. In its responses to DRA's data request (DR),[36] PG&E provided an additional matrix and tables that reconcile the estimated costs between the June and October fillings. With the additional information provided by PG&E, DRA was able to follow PG&E's testimony and supporting workpapers in its June and October filings. In conclusion, DRA finds PG&E's estimates reasonable. In Chapter 4, DRA includes these estimates in its revenue requirement, costs, and benefits calculations.

[34] Table 1-1 (Revised) of PG&E's response to DRA's Data Request (DR) No. 26, Q. 7a.

[35] Lines 3-5 on page 3. The total of Lines 3-5 including pre-deployment costs is $761.8 million.

[36] Q.6 and 7a of ORA DR No. 26.

III. DISCUSSION

A. PG&E's Estimated Costs for the AMI Meters, Modules, Network Materials, and AMI Operations

In its June filing, PG&E categorizes the: 1) meters and modules, 2) network materials, and 3) AMI operations costs under the Technology Acquisition and AMI Operations[37]. PG&E estimated costs are shown in Tables 1-1 to 1-4 in Chapter 1 of PG&E-2 (Unredacted). The total estimates for the above costs for 2006 to 2010 are [redacted] million. In its October filing, PG&E increased this amount by [redacted] million to a total of [redacted] million.

The meters, modules, and network materials costs for all electric and gas customers including, large commercial and industrial ("C&I") customers, are primarily comprised of vendor contract costs, material load, and sales taxes.[38] These costs are all capital related. The AMI operations costs are comprised of technical staff costs for PG&E's new AMI system organization. These costs are O&M related and include benefits, payroll taxes, office space, and equipment. Table 5-1 shows PG&E's updated estimated costs.

Table 5-1

Technology Acquisition and AMI Operation Costs[39]

NO.	**PG&E's Estimated Costs**	**($million)**
1	Meters and Modules	[redacted]
2	Network Materials	[redacted]
3	AMI Operations	[redacted]
4	**Total**	[redacted]

B. DRA's Analysis

DRA analyzes PG&E's cost estimates in three different areas: 1) reasonableness of the vendor costs the AMI meters and modules, 2)

[37] Chapter 1 of PG&E-2.

[38] Based on PG&E's supporting workpapers.

[39] Table 1-1 (Revised) in PG&E's response to Q.26, 7a. of DRA's DR No.26.

reasonableness of PG&E's input and cost assumptions including material load costs and staffing, and 3) verification of PG&E's testimony and workpapers.

1. Vendor Costs

PG&E's estimated vendor costs for the AMI meters, modules, and network materials are based on the contract costs.[40] PG&E added some costs for the retrofits of the AMI meters and modules. The reasonableness of the vendor costs are addressed in Chapter 2 of this testimony. In that chapter, DRA evaluates the reasonableness of the vendor costs from the contracts on a total basis including other AMI deployment related costs.

2. Material Load Costs and Sales Taxes

PG&E included the estimated material load costs for the AMI meters and modules, which are based on a factor of 17.5 percent[41] for 2006 and beyond in its June filing - adding a total of $14.1 million[42] to the total vendor costs.[43] PG&E later reduced this amount to $1.25 million and uses a lower factor of 14.1 percent for 2012 and beyond. This is a standard factor of material burden for all of PG&E's other capital projects.[44] The sales taxes are based on a rate of 8.25 percent, adding a total of $49.5 million[45] to the vendor costs. PG&E explained to DRA the reasons for the decrease in material load costs for 2006 to 2011, which were mainly because the installation of the AMI meters and modules are performed by the outside contractors. PG&E's handing of the materials will be minimal. DRA finds PG&E's estimated total adders (material load and sales taxes) to the vendor costs reasonable.

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[40] PG&E provided satisfactory explanations on the retrofit costs in its response to DRA's DR No. 29, Q.1 & 2.

[41] PG&E's response to Q. 1 of DRA's DR No. 29.

[42] Calculated using PG&E's supporting workpapers.

[43] 2006-2010.

[44] After the completion of the AMI deployment.

[45] Calculated using PG&E's supporting workpapers.

3. AMI Operations Staffing Assumptions and Cost Estimates

PG&E provided DRA additional explanations and workpapers for the AMI operations staffing assumptions and cost estimates.[46] DRA reviewed the information and consulted with its AMI consultant.[47] DRA finds PG&E's estimates reasonable.

4. Verification of PG&E's Testimony and Workpapers

DRA was able to readily analyze and verify PG&E's June filing, as estimated costs in the testimony were consistent with the supporting workpapers. The amended application that followed was a much more difficult document to process. PG&E's October filing contained changes in cost reporting formats that made comparisons to the June filing unnecessarily difficult. Impediments to DRA's review of the October filing included:

1. PG&E's testimony was inconsistent with its supporting workpapers,
2. PG&E's supplemental testimony categorizes costs differently from its June filing,
3. PG&E did not revise its original tables showing the updated estimates for the costs addressed in this Chapter.

Ultimately, DRA was unable to reconcile all the increases shown in PG&E's Supplemental Testimony and workpapers (October filing) without additional information.

In its October filing, PG&E states, "(i)n total, the updates concerning Technology Acquisition Costs and AMI Operations amount to an estimated increase in costs of $49.5 million."[48]

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[46] PG&E's responses to Q. 4 of DRA's DR. NO. 29.

[47] Plexus Research.

[48] Lines 8-9 in Chapter 2 of PGE-10.

Based on this testimony, DRA anticipated that this amount would be the increase in PG&E's estimated costs for the Technology Acquisition and AMI Operations from the June filing to the October filings. Obviously it does not match the increase in PG&E's updated estimated costs of $39.1 million and supporting workpapers. DRA was unable to reconcile the differences.

As stated above, in its responses to DRA's Data Requests, PG&E provided a matrix to reconcile these inconsistencies, updated Tables 1-1 to 1-4 in Chapter 1 of PG&E-2 and provided additional explanations. PG&E's responses show that out of $49.5 million that was stated by PG&E as the increase in Technology Acquisition Costs and AMI Operations, only $23.6 million is directly under these categories. The rest of $25.9 million is installation costs. The matrix also shows that the cost categories[49] in PG&E's October filing are different from its June filing. This causes confusions and makes it difficult to have an apple to apple comparison of the two filings.

With the additional information that PG&E provided in these data responses, DRA then was able to verify PG&E's testimony and supporting workpapers. However, in order to have an adequate record, the commission should direct PG&E to file an additional testimony providing a complete set of revised tables as originally shown in its June filing and reconciliation of the two filings.

IV. CONCLUSION

Based on DRA's review and analysis of PG&E's June and October filings, supporting workpapers, and responses to DRA's data requests, DRA finds PG&E's total estimates of [redacted] million for the AMI meters, modules, network materials, and AMI operations costs reasonable.

[49] For example, Technology Acquisition, Installation, Interface, and Billing.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 6

INFORMATION TECHNOLOGY COSTS

WITNESS: CHERIE CHAN

I. INTRODUCTION

Traditionally, most utilities required one set of meter reads per customer per month to produce a bill: the current month's end-read, and the previous month's end-read.[50] With an interval data-based system however, consumption reads are recorded more frequently and converted into consumption values. If California AMI Systems are to support the "collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs,"[51] data will have to be stored with a granularity of at least hourly data. Therefore, this change will require the processing and storage of 720 interval reads per 30-day month instead of two.

PG&E requests two fundamental changes to its Information Technology ("IT") Systems to manage this data increase:

1. An AMI Interface System to store, verify, clean, and distribute the voluminous interval-data records needs to be created;
2. An update to the Customer Information System ("CIS") to store interval meter data for billing, customer service, and other purposes.

PG&E requests $175.1 million dollars to cover the IT expenses associated with these changes. While DRA acknowledges that some improvements to

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[50] Assuming Residential non-time-of-use customers. The previous month's end-read is also known as the current month's start-read.

TOU meters require the difference of three values per month: on, off, and mid-peak.

[51] Joint assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis., February 19, 2004.

PG&E's data management systems may be required, some of PG&E's costs are unsupported and appear excessively high. DRA recommends that PG&E's ratepayers be responsible for no more than $142 million of these expenses that PG&E expects to incur in upgrading its IT systems, a reduction of $40 million.

II. THE AMI INTERFACE SYSTEM

A. What It Is

An AMI Interface system essentially stores and cleans interval-metered data, serving as a hub to further distribute this data downstream. Similar systems have been used in the utility sector for some time to manage interval data for some Commercial and Industrial customers. For example, PG&E has utilized a product called E-VEE™ to validate, edit, and estimate electric interval data for some commercial customers since at least 1998.[52] The E-VEE system also acts as a hub to distribute these data to other systems and parties such as the Interval Billing System, other internal programs such as load research and curtailment programs, and any third parties that are entitled to this information such as Energy Service Providers and Community Choice Aggregators.

Similarly, the new AMI Interface System would also store and verify interval-based data, but for far more customers. In this proceeding, PG&E requests $112.9 million to implement a new AMI Interface System distributed by Wireless Applications and Consulting Services, LLC ("WACS"). Below is a table of PG&E's estimated expenditures by type, along with a summary of DRA's recommended changes in bold and italics, to be explained throughout this chapter.

[52] Publicly available notes from VEE Conference Call April 7, 1998. http://ora.ca.gov/wk-group/dai/pswg3/veeconf980420.doc

TABLE 6-1[53]
PACIFIC GAS AND ELECTRIC COMPANY
INTERFACE AND SYSTEMS INTEGRATION – ESTIMATED EXPENDITURES BY TYPE
($ IN MILLIONS)

Line No.		Hardware	Software	PG&E Labor	External Labor	Total
1	Implementation					
2	AMI System:					
3	Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Other Systems:					
6	Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Operations & Maintenance					
9	AMI System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Other Systems	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Subtotal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Rounding					[redacted]
13	Total					[redacted]
	Adjustment from Errata					[redacted]
PG&E Request		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DRA Recommendation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

B. Is [redacted] million Reasonable?

1. PG&E's Costs are Comparable

PG&E states that "because PG&E will become an industry leader due to the scale and timing of its AMI Project deployment, the reasonableness of the costs discussed in this chapter can only be judged in relation to the efforts made by PG&E to ensure that the money spent on the AMI Interface System is used as

[53] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 2, Table 2-1.

efficiently as possible."[54] Essentially, PG&E asks the Commission to trust it's judgment, and suggests that its costs should not be compared to other very similar AMI projects currently evaluated around the world. Furthermore, in data request responses and in its testimony, PG&E consistently cites size and scalability issues as justification for its very high costs as highlighted in this chapter, even though common knowledge and in subsequent Data Request responses to DRA, PG&E states that "IT costs are relatively fixed regardless of meter deployment, while meter modules scale…"[55] PG&E further states that "most other utilities have focused on integrating the data generated by one AMI system *only* into their own billing systems."[56] [emphasis added] This claim implies that most other AMI systems are *not* used for outage detection, theft detection, capacity planning, and the host of other benefits PG&E addresses in its testimony. This logic defies common sense as well as other observations DRA has made in its research of the AMI community, other proposals from AMI Interface System vendors, and prior experience.

2. <u>Evidence of Cost Inflation?</u>

Some of PG&E's costs appear to be drastically overstated. DRA recognizes that some labor estimates could be inconsistent between utilities and allocations; however, some costs should be uniform across projects and estimates. For example, ratepayers should reasonably expect that large companies such as PG&E can achieve economies of scale when procuring items such as computer servers and other hardware to host the AMI Interface System. At the very least, large utilities with PG&E's purchasing power should be able to purchase items

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[54] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 2, p. 2-20, lines 20-24.

[55] Data Request Set DR-ORA-19, response to question 1.

[56] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 2, p. 2-20, lines 20-24.

such as hardware servers for a price comparable to that of a 12-employee software company.[57] This is not the case in PG&E's AMI application.

In both the WACS proposals and PG&E applications, line items for hardware expenses to host the AMI Interface Software are included, but with drastically different estimates. PG&E's estimates appear to be marked-up by a magnitude of over ten times the estimates provided by WACS. Below are the differences in hardware cost estimates between what WACS proposed in its Request for Proposal ("RFP") Response and its Best and Final Offer ("BAFO"), and what PG&E requests from its ratepayers:

Short Name	Filename	Cell #, Label	Supplied By	Cost
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

When questioned about PG&E's price adjustments, PG&E explained the ten-fold increase of hardware estimates over those in the WACS bid through three variables. PG&E stated that, "WACS used several incorrect assumptions when preparing its estimate of the hardware required for PG&E's AMI Interface System." These included the following:

1. That only 10 percent of electric customers will require the collection and storage of hourly interval data, whereas in fact, all of PG&E's electric customers will require this functionality;

[57] WACS, RFP Response Executive Summary, November 10, 2004. "WACS has [redacted] employees, excluding clerical employees that have been working on AMR related projects for the last four years. One hundred percent (100%) of these persons are and have been working on AMR projects since they began working for WACS."

2. That only two months of interval data will need to be stored, whereas in fact, PG&E will store interval data for seven years; and
3. That hardware will be required for only one IT environment, the production environment. WACS indicated within its RFP response that additional IT environments will require additional hardware. As discussed in the original Application, PG&E plans on building a production environment, as well as joint development/testing and disaster recovery environments."[58]

PG&E suggests in items one and two that IT costs scale up dramatically with size. This appears incorrect and contradicts PG&E's own assumptions in other documents.[59] DRA acknowledges that to some degree, IT costs are scalable; however, the extent that PG&E attributes scalability to costs is incorrect. "IT costs are relatively fixed regardless of meter deployment while meter modules scale directly with number of customers automated."[60] Nevertheless, despite PG&E's claims of scalability and the apparent "incorrect assumptions," PG&E says that WACS assumed that it would store data for only two months: DRA notes several diagrams and references in the WACS RFP Response that note long-term storage for 5-10 years.[61]

Furthermore, PG&E's third claim that WACS included only one production environment in its estimate is incorrect. The WACS RFP response clearly refers to and cites costs for both a production and test environment in its written proposals and pricing spreadsheets.[62]

[58] Data Request Set DR-ORA-11, response to question 2.

[59] Data Request Set DR-ORA-19, response to question 1.

[60] Data Request Set DR-ORA-19, response to question 1.

[61] Schedule 2 WACS Response.doc., p. 74.

[62] WACS RFP pricing template, Att. 2-6 (AMI Interface System Price Template) WACS.xls, includes line items for a Hot Backup Database server, (same as above) (cell A10), and a Backup for Application server, 2 CPU, 2 Gig of memory, NT or Unix server, (cell A16)

DRA finds PG&E's explanation for its ten-fold increase over WACS's offers unpersuasive, and finds no reason to question WACS's numbers in this instance. Therefore, DRA recommends that PG&E's AMI Interface System Hardware Capital Expense estimates be revised from $29.4 million to $10 million.

C. **Risk**

Within this task of implementing the AMI Interface System, PG&E further requests an overall 30-45 percent[63] risk cushion, or approximately $40 million dollars. This contingency figure is unreasonably high. PG&E has already extracted warranties from WACS to ensure that its product be both scalable to PG&E's Customer Base (and any potential acquired customers) and fully tested prior to delivery to PG&E.[64] The product as sold by WACS has already been implemented at Puget Sound Energy, with 1.7 million customers.[65] Furthermore, the concept of interval data management systems is not a new one at PG&E; whose staff is already experienced in similar interval data systems for commercial and industrial customers. In addition, PG&E has also hired IBM and EDS to help manage its IT efforts, which should significantly reduce project implementation risk. While DRA acknowledges that some risk contingency is reasonably considered, PG&E's proposed risk allocations are excessive. Specific recommendations relating to reductions in the allocated risk allowance are included in DRA's chapter entitled "Risk Allowance."

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[63] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 2, p. 20.

[64] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 2, p. 26.

[65] From the WACS Inc. corporate website: http://www.wacsinc.com/associates_success.html, and Data Request Set DR-ORA-36, response to question 1.

D. Conclusion

In sum, DRA recommends that the amount of money allowed to meet PG&E’s hardware requirements be drastically reduced in light of the evidence presented. Furthermore, DRA recommends that the dollar value of risk allocation in this project task is more than sufficient.

III. The Customer Information System

A. What It Is

The Customer Information System, known as Customer Care and Billing[66] (“CC&B”) at PG&E, is a “company-wide customer information and billing system”[67] that stores customer enrollment, billing, and payment information. In this project, PG&E seeks to update CC&B to store and interpret the interval data reads available from AMI. PG&E requests $66 million to upgrade its CIS from Customer Care & Billing version 1.2 to CC&B 1.5. DRA recommends that PG&E be awarded no more than $45.7 million to implement these upgrades, because PG&E’s hardware and internal labor estimates are too high as further explained in this chapter.

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[66] This software is licensed by SPL WorldGroup, Inc.

[67] 2003 GRC Testimony Phase 1, Exhibit PG&E-3, (CIS Replacement Project – Description and Capital Costs) Nov. 8, 2002, p. 2-24.

TABLE 6-2

PACIFIC GAS AND ELECTRIC COMPANY

CC&B UPGRADE – ESTIMATED EXPENDITURES BY TYPE ($ IN MILLIONS)

Line No.	Description	Hardware	Software	Labor - Internal	Labor - External	Other	*Total*
1	Phase 1						
2	Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Phase 2						
5	Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Phase 3						
8	Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Subtotal – Implementation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	O&M Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	O&M Savings	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Subtotal – O&M	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
14	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Rounding						[redacted]
16	PG&E Total						[redacted]
DRA Recommendation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

B. <u>Another Example of Cost Escalation?</u>

PG&E additionally requests $1.5 million dollars to purchase new 19 inch update monitors for their Customer Service Representatives ("CSR"),[68] because CC&B is optimally viewed with larger monitors. Assuming 600 customer service representatives, this comes out to $2500 per CSR. For comparison purposes, the average consumer can easily purchase a new 19 inch CRT monitor for $130, and an LCD monitor for about $400 at the local computer superstore. Furthermore, a new monitor is relatively easy to install, and should not require excessive labor and risk contingencies. Also, due to the timing of this project, the new version of

[68] PG&E Supplemental Testimony and Errata, October 13, 2005, Chapter 4, p. 1.

CC&B would unlikely be ready before Q1 2007. Prices would be even lower at that point.

While the total dollar value of the monitor-replacement project is relatively small in relation to the overall AMI project, such transparent and comparable figures, such as monitor prices, are not always available to DRA and interveners. In this case, it is, and PG&E's estimated costs are significantly higher than other available sources. Based on this evidence of cost-escalation, DRA recommends that general hardware expenses also be lowered from $17.3 million to $9.1 million to reflect realistic costs.

C. PG&E's Internal Labor Costs

To implement this upgrade of the existing system, PG&E requests $27.2 million dollars in internal labor costs.[69] This computes to 21,500 work days,[70] at an average cost of $158 per internal employee per hour, or an approximate annualized cost of $300,000 per employee. Also, assuming that each employee works an average of an entire year on this project and that each work-year contains 250 work-days, $300,000 per year 86 employees would be working full-time on the software upgrade project for an entire year, doing nothing else.

Not only are PG&E's labor estimates for the number of hours required to run this program excessively high as shown in the next section, but they also assume average loaded internal-staff costs of $158 per person per hour.[71] This estimate is inconsistent with PG&E's 2003 GRC filing, which assumes a loaded

[69] PG&E Supplemental Testimony and Errata, October 13, 2005, Chapter 3, p. 4, table 3-1.

[70] Data Request Set DR-ORA-09, response to question 9.

[71] Data Request Set DR-ORA-09, response to question 9. "PG&E estimates that the $27.2 million of PG&E labor costs accounts for approximately 21,500 work days…The estimated $27.2 million applies exclusively to PG&E labor expenses" $27.2 million / 21,500 days / 8 hrs/day= $158.14/hr.

cost of $78.98 per employee per hour, and an unloaded cost of $65.70 per employee per hour.[72] For comparison purposes, a senior programmer analyst (supervisor) at the CPUC earns a salary from $62,472 to $75,924 per year,[73] or approximately $31 to $38 per hour and a PG&E Billing Analyst Supervisor assumes a fully loaded standard rate of $69.32 per GRC. PG&E's labor estimate includes neither the $12.3 million in non-PG&E labor expense (consultants), nor the project management costs by IBM. The labor estimate presumably does not even include the staff already assigned to maintaining the existing CIS system. For these reasons, DRA recommends a revised labor estimate of $16.2 million, still an average fully loaded costs of $89.50 per hour with the same work load assumptions.

D. An Upgrade, not a Rewrite

PG&E's generous staffing request for this upgrade also contradicts PG&E's prior testimony that initially justified the cost of a new CIS system in the first place. When PG&E asked for authorization for the new CIS replacement project, PG&E made several claims:

"First, a packaged product removes the resource constraint on the internal PG&E development staff by making the vendor primarily responsible for upgrading and maintaining the product."[74] PG&E also claimed that: ". . . packaged products are more flexible, because, as commercial offerings, they are designed to be adapted by the vendor to meet the needs of a variety of utilities and to be changed and upgraded as the needs of the vendor and clients change. Finally, packaged products have fewer program defects due to the vendor's core

[72] 2003 GRC Phase 2, A.04-06-024, Errata workpapers to Exh. PG&E-2, Marginal Cost. Additional calculations have been performed by DRA.

[73] California Public Utilities Commission Classes and Salaries, Effective October 1, 2003.

[74] 2003 GRC Testimony Phase 1, Exhibit PG&E-3, (CIS Replacement Project – Description and Capital Costs) Nov. 8, 2002, Chapter 2, p. 2-13.

competency of software development and extensive experience with their product. This results in less in-house testing than an in-house CIS and the elimination of the in-house effort to fix the defects."[75]

Despite PG&E's earnest claims justifying an "off-the-shelf" CIS system to reduce internal labor costs and to provide for easy upgrades, PG&E's request for internal labor costs to upgrade its current CIS is still $28.6 million, and its external labor request is $12.3 million. This despite PG&E's claim in the GRC that a new CIS system would result in less work for internal staff, and would be easily upgraded.

Although upgrading a network software system does involve some work, DRA notes that PG&E is not writing new software. Instead, it is merely upgrading an existing product in the marketplace which already supports the feature PG&E is seeking. According to SPL product literature, "CorDaptix can store many forms of interval data, in any interval size. This includes raw and aggregated data, consumption values, standard load profiles, time-of-use maps, prices, contractual terms, and other interval factors."[76] Furthermore, with properly designed software upgrades, the interfaces that the software package interprets and produces, should not theoretically be affected by the upgrade. The same interfaces should still work. DRA acknowledges that some testing will be required, as well as some configuration to optimize new features. DRA, however, finds PG&E's labor estimates to be high in light of the evidence provided. DRA has already submitted a revised internal labor estimate. This estimate further supports a lower recommended value.

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[75] Id., pg 2-14, lines 1-8.

[76] Cordaptix: Functionality Overview v1.5.doc, pg 42. From Data Request Set DR-ORA-09, response to question 5. (Note that Cordaptix a prior name for the same CIS system developed by SPL Worldgroup.)

E. **Is there Double-Work?**

PG&E proposes to use the WACS AMI Interface system to verify, clean, store and frame the interval data into billing periods. All 720 meter reads per month are then exported in their entirety to the CIS system to be framed again for billing. The interval data is stored in both places. In some other Interval Data Repository and Customer Information Systems, including PG&E's existing Commercial and Industrial billing system, the data are simply framed into a few key billing determinants and imported into the CIS for customer information and printing to prevent double-work and duplicate storage.

Furthermore, the export of data from the WACS system and import into CC&B will result in further delays to the customer's data. "The proposed hardware and software configurations have been scaled to ensure that interval data for a 24-hour period will be imported from the meter-reading technology into the AMI Interface System within seven hours. Since the AMI Interface System undertakes a series of validation, editing and estimation procedures, there will be a further five hours before this data is available for use by CC&B"[77] and finally available to the customer.

Thus, according to PG&E's estimates, the earliest a customer could possibly be informed of his or her energy usage would be noon the following day. Passing this data through yet another filter, the CIS would cause even more delays to the customer. It could mean the difference between the customer receiving the data at 8 am and 1 pm. PG&E's proposal will result in duplicate work, and will also result in further delays in a customer's interval data information. While it would be challenging for any AMI system to provide real-time consumption information through its head-end software, some customers value this information with a minimum amount of delay.

[77] Data Request Set DR-ORA-19, response to question 2.

F. Conclusion

Based on PG&E's prevailing wages from the 2003 GRC, evidence of generous labor estimates, and more reasonable estimates of the costs of 19 inch monitors, DRA recommends that PG&E's revenue requests in hardware and internal labor be decreased from PG&E's CIS Upgrade proposal. DRA recognizes the need for software upgrades to provide timely consumption and billing information to the customer; however, DRA also seeks to balance this need with prudent and reasonable IT expenditures that do not unfairly burden its ratepayers.

SECTION II.A.

DRA'S ANALYSIS OF AMI COSTS AND BENEFITS

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 7

INSTALLATION AND DEPLOYMENT COSTS

WITNESS: LOUIS IRWIN

I. INTRODUCTION

Meter and network installation costs are considered in this chapter. Installation and deployment represent a significant portion of the total project costs -- approximately 19 percent per PG&E's Amended Testimony estimate.[78] Of the $331 million in projected costs, approximately 80 percent is attributed to the installation of meters and modules, the balance going to network installation and quality assurance testing.[79]

II. DISCUSSION

By far the largest consideration that needs to be addressed in the proposed installation is the meter and installation costs that would have occurred in lieu of this proposal, which will be called "routine" meter replacement costs. To a certain extent, PG&E will be replacing meters regardless of AMI due to the usual reasons (e.g. failure, damage, end of useful life). It is important to avoid an inadvertent double funding of meter replacement through both the AMI proposal and the GRC process. Whether these costs are properly assigned (even just once) to either the GRC or the AMI, this represents a cost savings to the ratepayer – that is, the marginal impact to the ratepayer is only the funds beyond which they would normally be financing new meters and installations. This issue will be discussed further below. First the issue of identifying the costs in question will be addressed irrespective of the GRC versus AMI issue.

[78] Exhibit PGE-1, Executive Summary, October 13, 2005, p. 2-3, Table 2-1.

[79] The $331 million: p. 3, Amended Application. The 80 percent ratio is calculated from subtotals: p. 4-1, PG&E-2.

In the scenario where there is no PG&E AMI installation, DRA estimates that PG&E would be spending $200.4 million on meter replacement anyhow during the deployment period. This estimate is based on historical costs ($162.2 million) for the years 2000 to 2004.[80] The adjustment from $162.2 million to $200.4 million is arrived at through applying the escalation percentage reflected in the 2000 to 2004 historical data forward through the deployment period. This escalation factor represents all reasons for increased costs (inflation, expansion of meter population, trends in meter aging, etc.).[81]

The $200.4 million dollar meter replacement cost needs a second adjustment, however, which might be called a "ramp-up" effect. That is, the possible savings do not immediately apply to the whole PG&E territory, because PG&E ramps up their installations over the deployment period. Before the first day of AMI meter installation, 100 percent of PG&Es meters will be of the old style and subject to the ordinary rate of maintenance costs. On the last day of AMI meter installation, 0 percent of PG&E meters will be of the old style and there will be no ordinary maintenance costs (all maintenance will be on AMI meters). The potential double funding issue only occurs for the territory where AMI installations are taking place, not all of PG&E territory. As a simplification, DRA assumed for a first approximation a steady rate of deployment and

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[80] DRA DR 31 q. 2c

[81] DRA proposes several adjustments to this figure to estimate what the installation and meter costs would be for the five-year deployment period (2007 to 2011). The first adjustment to the historical meter and installation costs is escalation. The escalation that DRA uses is the one that is reflected in PG&E's data response (14.96 percent cumulatively from 2000 to 2004). This is presumed to be from all relevant causes (e.g., inflation, expansion of meter population and trends in aging). When the same escalation is applied to the five year deployment period (2007 to 2011), the result is $186.5 million (up form $162.2 million). This actually grants PG&E a two year grace during the study period (2005 – 2006). Correcting for that, the figure rises to $200.4 million.

installation. Under this scenario, there would be half deployment at 2.5 years, the scheduled deployment midpoint. In this case, AMI only takes place in lieu of a conventional meter replacement half of the time (and half the originally projected repairs go forth).[82] Thus, the cost adjustment is halved to $100.2 million.

Due to the amount of money involved, however, a closer inspection of PG&E's actual proposed deployment schedule is warranted. This closer inspection uses PG&E's planned percentages of meters installed over the life of the deployment period.[83] The average level of deployment using PG&E's meter installment count was [redacted] percent deployed. [84] Therefore, using this figure, the cost adjustment would be [redacted] percent of [redacted] million, or [redacted] million.

Note that this $113.6 million dollar adjustment is DRA's recommendation given that PG&E's installation plans remain unchanged. PG&E states that meters and modules will be installed in warmer climates first.[85] Note that DRA is not proposing a change to PG&E's installation strategy here, but if by any chance, PG&E decides to enhance the deployment of AMI installation to meters needing immediate replacement, whether PG&E is on the currently proposed AMI installation route or not, then the DRA proposed cost adjustment would revert back to (include the entirety of) the originally proposed $200.4 million.

The issue of how this $113.6 million is apportioned between AMI and GRC responsibility is now addressed. The AMI proposal is not modified for any possible GRC adjustments for meter installation and replacement issues.[86] The

[82] A pictorial representation of this principle would be a square with a diagonal from the lower left corner to the upper right corner. The diagonal line represents steady AMI installation and it cuts the area of the square in half

[83] File Exhibit2 Chapter 4_Workpapers_Confidential_June.XLS, Worksheet Ex2Ch4a, line 80.

[84] Ibid. 56.7 percent was arrived at by averaging the cumulative percentages determined from line 80.

[85] Exhibit PG&E-2, AMI Project and Installation Costs, June 16, 2005, p. 4-6.

[86] The response to DR 31 Q 2c states that meter replacement and installation costs are addressed in the GRC – that the AMI proposal makes no cost adjustment based on expected GRC actions.

previous GRC settlement incorporated into rates the funds for the expected replacement of meters through 2006. It is anticipated that the current GRC (Test Year 2007) will not be able to anticipate and correct AMI-related meter installation and replacement costs. The AMI decision will not occur far enough in advance of the current GRC to allow its inclusion as an adjustment to the Revenue Requirement. This situation, however, can be corrected in the 2010 Test Year GRC. This would be the 5th year of the deployment period. For this adjustment, DRA uses the figure for cumulative percentage of meters deployed by the end of 2009 [redacted].[87] Therefore, [redacted] million dollar adjustment ([redacted] million) should be applied to the AMI cost proposal. The remaining [redacted] million should be logged as an adjustment down in 2010 of the 2010 Test Year GRC. For the purposes of this AMI proposal, this can be viewed as a future benefit to ratepayers.

Having a huge influx of new meters should also create future savings (from GRC expenses). A major portion of the meter stock will have been renewed. Prior to the AMI period, meter and installation costs were over $35 million in 2004.[88] DRA will not investigate at this time what percentage of these costs is attributable to replacement meters as opposed to customers at new developments or the percentage of these meters being replaced by AMI. For illustrative purposes only, consider if the figure were found to be half for replacement ($17.5 million) and that all these meters were replaced by the AMI deployment. If the costs were escalated to $20 million per year in 2012, that would represent a significant savings to ratepayers. This rests on the assumption that perhaps for the first ten years after deployment (2012 to 2021) these new meters are relatively trouble free.

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[87] File Exhibit2 Chapter 4_Workpapers_Confidential_June.XLS, Worksheet Ex2Ch4a, line 80. Cumulative total calculated from individual year totals. Cumulative for 2009 is being used.

[88] DRA DR 31 q. 2c

Under this illustrative scenario, ratepayers would save $200 million over those 10 years.

The installation contract has been awarded to Wellington. There are some prima facie concerns, since the deployment calls for 9 million meters to be addressed with a new module or meter replacement on an aggressive time schedule. DRA is not placing Wellington's credentials under question. DRA simply wishes to note that there would be greater safety in having contracts with more than one installer or at least an arrangement with an installer in reserve. The overall AMI project productivity would favor multiple installers rather than only having a safety back-up arrangement with another installer. PG&E cites that Wellington has installed 1.3 million DCSI meters / modules at PPL (presumably its largest installation).[89]

Installation of AMI meters and modules affords PG&E an excellent opportunity to detect meter and line tampering and, ultimately, electricity theft. PG&E claims that the Wellington contract has incentives to detect such theft, but PG&E does not quantify the value of such detection in its benefits. PG&E has admitted to electricity thefts ranging from 1 percent to 2.5 percent of sales.[90] Taking a midpoint of this sales range and assuming the AMI installation leads to a 25 percent reduction in theft. This leads to an annual savings for honest ratepayers of $48.5 million.[91] While this should not directly decrease PG&E's revenue requirement (since the same funds are coming in, just from different parties) it should lead to a decrease in rates and the revenue requirement per paying customer. The increased equity would also enhance PG&E's quality of service. Note that this is only a decrease per paying customer and not an absolute Revenue

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[89] Exhibit PG&E-2, AMI Project and Installation Costs, June 16, 2005, p. 4-3.

[90] "*Revenue Metering Loss Assessment*," EPRI, November 2001. p. xi.

[91] Savings only to honest payers. Thefts were formerly covered by paying accounts. Deterrence estimates, Ibid., p. XIV. Based on deterrence of 2004 sales revenues as reported in PG&E's 2004 Annual Report.

Requirement decrease. However if surveillance of theft leads to incarceration of a utility customer involved in a high volume electricity theft, then total load and associated Revenue Requirement would presumably decrease.

New meters would also improve metering accuracy. The kind of meters serving most PG&E customers now (induction meters) can be inaccurate in either direction. The trend over time, however, is to reduce the sales figures approximately 0.4 percent of all sales. Meter specifications normally allow them to be up to 1% slow. Therefore, a meter that is 0.4% slow can easily stay in service. Some of this system degradation may also be attributable to customer abuse or tampering with the equipment, but does not rise to the level of blatant theft. At 0.4 percent of sales, the benefit would be $44.3 million annually.[92] Although this loss cannot be characterized as clearly favoring honest ratepayers over those that circumvent the rules (like definite theft), it should still be characterized as a benefit to honest ratepayers. This is because the most forthright of ratepayers would want their meters to be accurate and up to specifications whether the new meter favored their bank account or not. Accurate metering is a benefit to all fair minded ratepayers. Increased accuracy also reflects well on PG&E. A final bottom line to consider is that correcting the .4 percent meter inaccuracy lowers rates by that amount – a clear benefit to fair minded rate payers.

III. CONCLUSION

DRA'S recommendations in this chapter include $100.2 million in cost reductions regarding installations that would have happened in lieu of the AMI proposal. Furthermore, DRA proposes that there are additional ratepayer benefits of $92.8 million annually due to enhanced meter accuracy and electricity theft detection.

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[92] Based on 2004 sales revenues as reported in PG&E's 2004 Annual Report.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 8

RISK ALLOWANCE COSTS

WITNESS: LOUIS IRWIN

I. INTRODUCTION

DRA's primary concern regarding PG&E's risk contingency fund is that it is too high. The total amount requested is $128.8 million, or 7.4 percent of the total budget of $1745.1 million.[93] DRA supports a risk contingency of 4.8 percent, ($94.0 million) as more reflective of the real risks that PG&E faces with its AMI project.[94]

II. DISCUSSION

PG&E presents no comparative or statistical analysis, nor any other objective measure upon which the Commission could judge the reasonableness of PG&E's contingency funding request. Instead, PG&E's request is based solely on the opinions of its witnesses.[95] Given the apparent paucity of useful data on this issue, DRA will limit its analysis of PG&E's request to two issues where information is in fact available: PG&E's request for a 35 percent risk allowance for its interface and systems integration areas as well as 35 percent for the customer care and billing upgrade costs.

On its face, PG&E's contingency request appears excessive when comparing it to the testimony it presented to support its vendor choices. PG&E

[93] $128.8 million risk contingency fund over the total budget of $1.745 billion. Amended Application, October 13, 2005, p.3. Note that the contingency fund in the original application was approximately 8 percent, but was at the same level of funding ($128.8). Therefore, PG&E only got the contingency fund down to 7.4 percent in the Amended Application by expanding other costs.

[94] Amended Application, October 13, 2005. p. 3.

[95] Exhibit PG&E-1, Executive Summary, Chapter 2, p. 2-30, lines 25 – 28.

claims that it has protection regarding its vendors in the form of binding contracts and penalties for performance failures.[96]

PG&E also states that risk was decreased through the use of vendor diversity in its contracting practices. That way, the risk is spread amongst different vendors rather than on PG&E alone.[97]

The most compelling piece of information that raises a red flag regarding the reasonableness of PG&E's contingency calculations is PG&E's proposal to spend $87.9 million for IBM's services as an integrated service manager.[98] The use of IBM is not being contested per se, only its hiring in tandem with a 35 percent risk allowance in two key areas. IBM's responsibilities will be far reaching, including integration, scope, scheduling, cost, quality, human resources, communications, procurement and risk management.[99] IBM will therefore influence many elements of the project which are subject to risk, as well as the risk management issues themselves.

As stated above, IBM's fee is $87.9 million. The contingency allowance on top of that is $33 million for interface and system integration, an area that only has $94 million in the budget in nominal terms.[100] This begs the question: Is PG&E exaggerating the expertise of IBM, or is it unreasonably padding its contingency request? Given the management fees and experience already being dedicated to this area, DRA feels that a risk allowance of 10 percent, or $9 million, is more than adequate.

PG&E has also unreasonably cushioned the customer care and billing portion of the project with a 35 percent risk allowance. Upgrading customer care

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[96] Exhibit PG&E-1, Executive Summary, June 16, 2005, p. 2-21, lines 4 – 18.

[97] Exhibit PG&E-1, Executive Summary, June 16, 2005, Chapter 2, p. 2-20, 2-21, lines 23 – 32.

[98] PG&E Amended Application, p. 3, October 13, 2005.

[99] Exhibit PG&E-1, Executive Summary, June 16, 2005, Chapter 2, p. 2-25, lines 20 – 27.

[100] PG&E Supplemental Testimony, p. 10-2, Table 10-1, Interface and systems integration: $94.0 million. At a risk allowance of 35 percent this would be $33 million.

and billing, while addressing a fairly new application, still is based in the world of software upgrades. While software upgrades can be challenging, this should not involve a degree of difficulty that warrants the contingency funding that PG&E is assigning to it. Most importantly, PG&E has decades of experience with programming upgrades. Therefore, DRA finds PG&E's proposed risk allowance, which amounts to an additional $29.8 million, to be excessive.[101] DRA's proposal for risk allowance is 10 percent. At a level of 10 percent the risk allowance would be $8.5 million.

III. CONCLUSION

While PG&E considers a fair amount of issues in determining its contingency fund, the end result is still based on its professional judgment. It does not introduce a comparative analysis or any other objective measure on which the Commission can safely base its decision. DRA reviewed two subproject areas, system integration and customer care and billing and found PG&E's allotted risk allowance to be excessive. Lowering the risk allowance in these two areas to 10 percent creates a savings of $44.8 million to ratepayers and lowers the overall risk allowance from 7.4 percent to 4.8 percent.

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[101] Ibid, Interval billing system: $85 million. At a risk allowance of 35 percent this would be $29.8 million.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 9

METER READING BENEFITS

WITNESS: MARSHAL ENDERBY

I. INTRODUCTION

This chapter concerns the operational benefits associated with meter reading resulting from Pacific Gas and Electric Company's ("PG&E") Advanced Metering Infrastructure ("AMI") Project deployment. Over 50 percent of the potential benefits predicted for the AMI Project relate to meter reading. Specifically, AMI is expected to eliminate the labor and non-labor costs required for regular manual monthly meter reading and change party/special requests. Meter reading benefits consist of two parts: (1) savings associated with meter readers and support personnel; and (2) savings associated with avoided maintenance of PG&E's current Itron handheld meter reading system and avoided purchases of similar future meter reading systems.

The AMI project will make it possible to automate the meter reading of virtually all electric and core gas meters currently read by meter readers. Labor costs to be saved include management, field, clerical and support employees. Non-labor costs include materials, employee-related expenses (e.g., meals, travel allowances and reimbursed mileage, pagers, desktop and cell phones), PG&E vehicles; dog bite prevention training, network charges and the costs of the Itron maintenance contract. PG&E estimates that this will result in a total annual cost savings of $86.1 million for full deployment of the AMI Project for all electric and core gas accounts.[102] This cost savings is the labor and non-labor value for 2005 in thousands of dollars.

[102] In addition, costs associated with employee injuries, auto accidents and third party claims

(Continued on next page)

Of the $86.1 million total annual cost savings estimated by PG&E, about $79.1 million relate to labor savings for monthly meter reading and involve regular and senior meter readers, supervisors, managers and support staff. Another $6.2 million concerns labor cost savings for change party and special reads and various support functions. The estimate for non-labor savings is $778,000 annually. Most of this savings involve the Itron maintenance contract ($619,000) and network/FFIOC modems ($238,000).

A. <u>DRA Issue 1 – Costs of Creating New Positions, Training, and Severance</u>

PG&E has approximately 1,040 people, mostly engaged in meter reading and billing-related jobs, whose employment status will be affected by the AMI Project. (PG&E Original Testimony, June 16, 2005, PG&E-3, Chapter 6, p. 6-1) PG&E has developed a labor strategy to minimize impacts to this workforce. In order to mitigate impacts, PG&E and the Union have agreed to various measures, which include creating new positions to install AMI meters and skills training to help employees test and qualify for other positions. New positions would be created to work on the AMI project (e.g., installing meters). PG&E estimates that a total of $5 million will be needed for the costs of meter installations and about $1.7 million will be needed for training costs. In addition, PG&E estimates that about $13.4 million will be needed for severance costs.[103] (PG&E Original Testimony, June 16, 2005, PG&E-3, Chapter 6, pages 6-2 and 6-3)

(Continued from previous page)
would be reduced and/or eliminated. The estimated cost savings are included in Exhibit 5, Chapter 1, and in Exhibit 5, Chapter 5.

[103] See A.05-06-028, "Original Testimony of PG&E," PG&E-3, Chapter 6, pages 6-2 and 6-3. Footnote 2 on page 6-2 says it is estimated that the costs of installation shown in Exhibit 2, Chapter 4 ("Original Testimony"), may increase by approximately $5 million to create new AMI related positions.

PG&E appears not to have included the $5 million of meter installation costs within the project cost estimates used to compute a present value of the revenue requirement for purposes of comparing costs and benefits. If this has not been done, DRA recommends that these costs instead be subtracted from the benefits prior to computing the net present value of the revenue requirement. This could be done in a manner similar to the way in which PG&E subtracts estimated severance costs over a multi-year period from the nominal dollar benefits used to calculate the net present value of the benefits.[104]

PG&E also has not included the full costs of training and severance ($1.7 million plus $13.4 million or $15.1 million) within the calculations used to compute the net present value of revenue requirements. Instead, PG&E has only included about [redacted] million.[105] This is a difference of about $3.1 million.

DRA has subtracted the costs of meter installation ($5 million total) plus the difference in the costs of severance and training discussed above (about $3.1 million) from the meter reading benefits that PG&E has calculated for the years 2006 through 2011. The training and severance costs were spread over the years 2008-2011 and the new position costs over the years 2006-2010. This was done by spreading the costs over the years based on the AMI build rate shown in Figure 4-1, "Project Implementation and Deployment Costs."[106] (PG&E Original Testimony, June 16, 2005, PG&E-2, Chapter 4, page 4-6).

[104] See the workpapers supporting Exhibit 5, Chapter 1, line 20.

[105] See EX3CH1a, PG&E's "AMI Project-Benefits," Workpapers Supporting Supplemental Testimony and Errata, Phase II, Chapter 10 and Exhibit 5, Chapter 1 (updated 10/13/05).

[106] The costs were spread using line 20, severance costs, in EX3CH1a from the Exhibit 5 Chapter 1 workpapers provided on Oct. 12, 2005.

DRA Issue 2 – Estimating Bills for Customers Whose Meters AMI Installers Have Been Unable to Change

PG&E seeks temporary authority to estimate bills for customers whose meters AMI installers have been unable to access and change, despite repeated attempts to contact the customer, until PG&E is able to obtain access and change the meter to AMI. (PG&E Supplemental Testimony and Errata, October 13, 2005, Chapter 6) PG&E says that, if the California Public Utilities Commission declines to give PG&E authority to estimate bills during the implementation of AMI, business case costs will be higher. PG&E says that if it is required to read meters (after the installation vendor's three failed attempts) for an additional one, two, or three months, the estimated total incremental costs that would be added over the entire deployment period are $3.6 million, $6.5 million, and $9.4 million, respectively.[107]

If one of the three above outcomes occurs, then the benefits should be reduced accordingly. Alternatively, the additional expected cost could be added to project costs for purposes of calculating a present value of the revenue requirement ("PVRR") of costs to be compared with an unadjusted stream of benefits used to calculate the PVRR for benefits.

PG&E does not appear to have authorization to estimate bills for customers who do not respond to an AMI installer's attempts to change their meters. Since this is situation at present, DRA has subtracted the incremental costs ($9.4 million) from the meter reading benefits that PG&E has calculated for the years 2006 and 2007. This was done by spreading the costs over the years 2006-2010 based on the AMI build rate shown in Figure 4-1, "Project Implementation and Deployment

[107] PG&E appears to assume that, within the three months, all customers who failed to respond initially will have been contacted and PG&E will have gained access as required under PG&E's Gas Rule 16.A.10 and Electric Rule 16.A.11. Thus, all meters will have been changed to AMI meters within a three month period. However, PG&E does not explicitly address in its testimony what will happen if this is not the case.

Costs."[108] (PG&E Original Testimony, June 16, 2005, PG&E-2, Chapter 4, page 4-6)

B. <u>DRA Issue 3 – Deployment Benefits Realization Methodology</u>

Deployment involves installation of AMI meters and associated infrastructure. Deployment of AMI will move from one headquarters to another throughout an identified Division.[109] Once the equivalent of a meter reading route string has fully converted to AMI (automated meter reads are used for customer billing), meter reading employees will begin to be released. Between the original June 2005 AMI filing and the revised filing in October 2005, PG&E has changed several assumptions that have increased the overall benefits from meter reading by $13.8 million in present value of the revenue requirement.

1. In the June, 2005 AMI application (A.05-03-028), PG&E assumed that benefits for regular monthly meter reading would start to be realized in approximately the fifth month after deployment began in a Division. This assumption was based on a gradual start-up in a Division, two months to convert the first meter reading routes, and time for converting enough meter reading routes to be equivalent to a full meter reading string (a month of meter reading routes). The October 2005 AMI submittal now assumes that meter reading benefits can begin to accrue during the third month after deployment begins. PG&E's stated reason for this change is based on a review of the refined installation schedule and the number of meters that can be

[108] The costs were spread using line 20, severance costs, in EX3CH1a from the Exhibit 5 Chapter 1 workpapers provided on Oct. 12, 2005.

[109] Traditional geographic area utilized by PG&E including one or more headquarters.

converted to AMI technology within the first two months of deployment.

2. The original filing also assumed that the last benefits from a Division will be captured two months after deployment has been completed, based on the required time to complete workforce displacement activity. The October 2005 AMI submittal now assumes that the final benefits may be captured within the first month after deployment. PG&E states that the revised assumption is based on a refinement of workforce attrition and displacement assumptions and the assumption that PG&E will be granted the authority to estimate bills on an interim basis for customers whose meters have not been changed to an AMI meter despite repeated attempts to contact the customer.

3. Lastly, PG&E changed the original assumption that labor savings from meter readers will be spread equally by month during Division deployment. The revised assumption is that labor savings from meter readers will be proportional to the number of meters converted by headquarters.

Most of the $13.8 million increase in the PVRR is due to the first changed assumption above – that the benefits for regular monthly meter reading would begin to accrue during the third month after deployment begins (rather than the fifth month). These benefits are largely a function of the meter installation ramp-up by the contractor. According to PG&E, the changed assumption and benefits are due to looking at the actual (current) installation schedule that became available after the original AMI filing in June, 2005. The ramp-up is now scheduled to take two months, as opposed to the previous estimate of four months.

The change in the benefits is, for the most part, based on information that became available to PG&E after the June AMI filing. DRA does not object to using updated information about the installation schedule to increase benefits. However, this change does demonstrate how sensitive the estimation of the total benefits ("PVRR") is to a seemingly small change in the deployment schedule. The $13.8 million is about 1.3 percent of the operational meter reading benefits of $1,074 million in PG&E's amended application, October 2005.[110] PG&E acknowledges this sensitivity in a discussion about operational meter reading benefits and costs: "The primary risk or uncertainty related to meter reading benefits would be associated with changes/delays to the deployment schedule/strategy and, as a result, to the timing for realizing the stated meter reading benefits." (PG&E Original Testimony, June 16, 2005, PG&E-3, Chapter 1, page 1-6)

II. CONCLUSION

DRA has reviewed PG&E's cost estimates related to job training, severance pay, the creation of new positions, and continued meter reading (in lieu of estimated billing). The cost estimates total about $17.5 million over the entire deployment schedule: $3.1 million for training and severance costs, $5 million for AMI related jobs for meter readers, and $9.4 million for reading meters in lieu of using estimated billing. DRA spread these costs over the deployment schedule and deducted them from yearly meter reading benefits for purposes of calculating a present value of the revenue requirement. The result was to lower the PVRR by about $13.7 million.[111]

In regard to DRA Issue No. 2 above (estimated billing), DRA opposes PG&E's proposal for an unlimited ability to perform estimated billing in the

[110] Total PVRR benefits amount to about $2,024 million.

[111] The PVRR was calculated using DRA's cost of capital of 8.79 percent. The PVRR was lowered by $13,744,000.

future. Reasonable restrictions on the use of estimated billing should be retained and any partial exemption from the requirement to read meters considered in this proceeding should be consistent with the results of the Commission's current back billing investigation.

DIVISION OF RATEPAYER ADVOCATES
CHAPTER 10
TRANSMISSION AND DISTRIBUTION BENEFITS
WITNESS: LOUIS IRWIN

I. INTRODUCTION

This chapter addresses transmission and distribution ("T&D") operational benefits. PG&E presents four areas in which the proposed AMI system will benefit transmission and distribution operations: 1) outage restoration, 2) avoided dispatch, 3) momentary outage detection, and 4) T&D engineering and planning. These benefits will be addressed first before turning to other potential benefits that PG&E fails to address.

Of the four benefits that PG&E addresses, the last one, T&D engineering and planning is the most significant. PG&E notes that other utilities have attained a benefit savings of up to 25 percent for annual system design optimization. The ranges that PG&E presents for system optimization in other utilities were 15 percent to 25 percent and 4 percent to 19 percent in annual repair costs.[112] PG&E does not present a weighted average of the two measures. An unweighted average would be approximately 16 percent.

PG&E asserts that its computerized grid modeling tool (the Centralized Electric Distribution System Analysis ("CEDSA") already achieves much of these T&D system optimization benefits. PG&E claims that this contrasts with the other utilities mentioned, which did not have this advantage. On this basis, PG&E projects only a 1 percent system optimization benefit.[113] This is substantially less

[112] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5.

[113] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5.

than the 16 percent benefits being achieved in this planning area by other AMI projects. DRA does not feel that PG&E's assertion of a 1 percent performance difference due to AMI has been adequately justified and demonstrated by PG&E. The rationale seems to entirely rest on pages 2-5 and lines 1 – 5 of page 6 of Exhibit 3 (June 16, 2005) with no updates or errata posted on October 13, 2005. PG&E's argument relies on the strength of PG&E status quo planning tool entitled Computerized Electric Distribution System Analysis (CEDSA). There seems to be only one sentence describing model inputs (Exhibit PG&E-3, p. 2- 5, lines 19 – 20). PG&E describes the inputs as peak summer and winter load data. There seems to be only one sentence describing performance features of the CEDSA model (Exhibit PG&E-3, p. 2-5, lines 20 – 21). Here PG&E states that the CEDSA model,

"Has the ability to utilize current load data to run load, voltage and protections models of the electric distribution system."[114]

In the very next sentence of PG&E testimony, PG&E states that AMI will provide *additional real-time loading* benefits. This seems true but contradicts the above quote that the CEDSA model utilizes *current* load data. Since the CEDSA system does not have real-time data, perhaps PG&E means that the CEDSA system will use the most recent load data, which according to its described inputs (discussed above) would be peak summer and winter load data. That data would certainly be current, real-time data *twice a year*. The implied assertion that other utilities do not have feeder peak load data is difficult to accept. Utilities commonly collect such data. Perhaps PG&E is asserting that the CEDSA *analysis capability* is what provides the unique value that other utilities don't get, but PG&E provided no description of this capability.

[114] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5, lines 20 – 21.

PG&E's approach to the issue of determining AMI-related T&D system benefits seems correct in that it does rest on the strengths of its status quo CEDSA system. However, PG&E's testimony on the matter seems to be limited to only a few sentences of description and justification. Gathering peak load data is something that many other utilities do. PG&E asserts that its CEDSA system provides analytical tools that are beyond the capabilities of most other utilities, but fails to give supporting evidence.[115] Considering the importance and financial ramifications of the issue, DRA maintains that PG&E's testimony is insufficient to accept a 1 percent system optimization gain without question and without further justification from PG&E.

DRA will discuss and review studies that reveal two ways in which an AMI system can create T&D operational savings for PG&E beyond its CEDSA system. The first could be described as general wear and tear on the T&D system and the second involves better outage tracking.

The summer and winter peak data that the CEDSA system provides to PG&E is sufficient to describe peak-capacity issues. However, this should not be PG&E's sole T&D operational concern. An AMI system will be able to provide information on system load by detailed geography (transformer or meter level, if necessary) for many more time points than merely summer or winter peak. And for these peak load times, an AMI system will be able to provide a detailed peak load shape showing system-wide stress. When it comes to efficient maintenance of the T&D system, the duration at, over, or even near peak capacity is of concern. Greater system load at greater duration produces more heat. A test widely used in American manufacturing of any newly developed product is a prolonged heat duration test. This serves as a proxy test for aging. Simply put – heat ages a wide variety of materials, including metals.

[115] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5, lines 14

(Continued on next page)

Turning our consideration specifically to the T&D system, substation and distribution transformers can withstand significant overloads for short periods, but longer duration overload allows excess heat to build up with more serious consequences. For example, a brief, sharp peak shortens transformer life much less than a longer-lasting peak. Furthermore, when overloaded conductors heat up, they expand and they sag. This line sag can lead to unwanted contact with tree branches of other structures, leading to both outages and possibly, fire. One such outage in the summer of 2004 became a wide spread power outage. Momentary conditions will not have that effect – it takes a prolonged overload on a very hot day. Having detailed load information that can be provided by AMI helps avert such situations.

Not only can AMI help avert outages, it can show which parts of the T&D grid, even in times of extended high load, still have an excess of capacity. AMI savings might not be immediate, but the AMI data could be used, whenever old transformers are being replaced to ensure that correctly sized transformers are installed. In this example, a "correctly" sized transformer is a smaller, less expensive one. Since management of the T&D system is necessarily risk averse (no one wants to be responsible for a power outage) oversizing transformers must be a common situation. But the AMI system, in providing more detailed load information will provide the data to correct this problem over time.

A case study of AmerenUE[116] illustrates the value of an AMI system to T&D system maintenance. PG&E in its testimony also cites AmerenUE's AMI

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– 16.

[116] Founded in 1902, AmerenUE—Missouri's largest electric utility —provides energy services to approximately 1.1 million customers across the eastern half of Missouri, including the greater St. Louis area. AmerenUE serves 65 Missouri counties and 500 towns. More than half (55 percent) of AmerenUE's electric customers are located in the St. Louis metropolitan area. See http://www.ameren.com/ABOUTUS/ADC_AU_FactSheet.pdf. See also http://www.ameren.com/AboutUs/ADC_AU_FactSheet.pdf.

related savings regarding transformer utilization and purchasing activities to be 20 percent.[117] Early in its AMI implementation, AmerenUE experienced a record peak load day (at 102 degrees Fahrenheit), but its transformer load was still rated at 58.3 percent capacity.[118] AmerenUE was able to measure its distribution system capacity through the use of the "System Load Snapshot," ("SLS"), developed by AmerenUE in collaboration with Cellnet now a feature of Cellnets' AMI system. This feature allows synchronized measurement of demand data on the entire population of meters. These data can be aggregated for its entire inventory of transformers. For AmerenUE, the SLS data proved 8 percent to 23 percent more accurate than its previous system for monitoring transformer load (SCADA: Supervisory Control and Data Acquisition).[119] AmerenUE also found that SLS data was more accurate than statistical modeling by 22 percent to 46 percent.[120] So for AmerenUE, the statistical model had the poorest performance results. Although PG&E's CESDA system is not identical to AmerenUE's statistical model, PG&E does describe it as a statistical model.[121] Therefore, without further information, DRA would tend to believe that PG&E's CEDSA model would have the same performance issues that the AmerenUE statistical model had when compared to its AMI system (which utilized the System Load Snapshot). PG&E's estimate that its AMI data will improve on the results of PG&E's statistical techniques by just 1 percent is unconvincing when AmerenUE's results were improved by 20 percent.

AMI can also be used to survey other system characteristics that lead to capital and operations savings. For instance, the Minnesota Valley Electric

[117] Exhibit PGE-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5.

[118] *AmerenUE Case Study System Load Snapshot*, Cellnet, 2004, p. 3.

[119] Ibid.

[120] Ibid.

[121] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, p. 2-5, lines 20 – 21.

Cooperative used TWACS by DCSI to create a database of momentary outages by time, location and frequency.[122] This generated savings by allowing the cooperative to concentrate its system upgrades in a more cost-effective manner.

In light of these experiences of other utilities, DRA finds that PG&E's estimate of expected benefits is low – that PG&E has over-valued the benefits of its current CESDA system. PG&E has failed to show substantively how its status quo CEDSA system equals or outperforms AmerenUE's status quo SCADA system (and thus, why the potential efficiency gains from AMI deployment would be any less). PG&E fails to show how its CEDSA modeling system would avoid the pitfalls of the modeling inaccuracies (22 percent to 46 percent) that AmerenUE found when compared to the SLS analysis. PG&E has failed to acknowledge that CEDSA cannot perform a momentary outage analysis and achieve the benefits that were demonstrated in the Minnesota Valley Electric Cooperative case study. Furthermore, DRA recently issued a formal Data Request (DR) to PG&E on historical transformer replacement costs. These are one example of the types of costs that an SLS analysis (supported by hourly data from an AMI system) could potentially reduce by detecting failures due to overloading that may be rapidly approaching. This data could also reveal cases of extreme oversizing of transformers, a problem that was revealed in the AmerenUE Case Study discussed above[123] as well as PG&E's own testimony.[124] Yet PG&E deemed this data request "irrelevant."[125] In the absence of information on these transformer costs, and without a better description and demonstration of PG&E's CEDSA model

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[122] *TWACS Customer Solutions, Analyzing Daily Blink Counts, Case Study – Minnesota Valley Electric Cooperative*, DCSI Inc., 2004. "Blink" = momentary outages. "TWACS" = Two-Way Automatic Communication System.

[123] Recall the 58.3% capacity load readings obtained on a 102 degree day.

[124] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, Chapter 2, p. 2-5, lines 7 – 9.

[125] DRA DR #43 all questions (1 – 6), January 11, 2006.

benefits, PG&E has provided inadequate justification of a 1 percent T&D system optimization benefit has not been demonstrated yet. With the information that is in evidence at this time, DRA believes that a reasonable and conservative estimate is that PG&E will be able to achieve half the 20 percent savings rate that AmerenUE attained. To be cautious, however, DRA notes that AmerenUE's gains are on transformers and purchasing alone. While transformer utilization and purchasing is a significant portion of T&D engineering costs, it is not as broad as the whole range of T&D engineering and planning costs. The CapGemini study cited above however does have greater breadth in that multiple utilities are surveyed and a broader range of costs are considered.[126] The unweighted midpoint of cost ranges cited by PG&E in regard to this study is 16 percent. Without further evidence being presented by PG&E, DRA believes that it is reasonable for PG&E to attain half the savings that were attained by the utilities in the CapGemini study, or 8 percent. At an 8 percent improvement in T&D engineering and planning, the benefit would be $5.92 million, compared to the PG&E proposal of $0.74 million. This is an increased benefit of $5.2 million annually.

Information that can be obtained from an AMI system facilitates quicker, more efficient outage detection and restoration. For outage restoration, PG&E cites a Cap Gemini study pointing to AMI-related savings of 3 percent to 8 percent annually. (p. 2-3, PG&E-3). PG&E estimates its savings based on 5 percent of its outage restoration expenses, or $7.2 million. PG&E presents no arguments for PG&E performance to be at either end of the Cap Gemini range. DRA will not make any arguments either, except to note that the midpoint of the Cap Gemini range as presented (3 percent to 8 percent) is 5.5 percent and would lead instead to benefits of $7.9 million annually.

II. ADDITIONAL BENEFITS

[126] Exhibit PG&E-3, AMI Project Operational Benefits and Costs, June 16, 2005, Chapter 2, p. 2 -
(Continued on next page)

The Commission should also consider economy wide benefits of the AMI system. The improved outage restoration that PG&E claims that AMI will bring will also generate increased sales and avoided damages (e.g. losses due to a disruption of refrigeration, stores and restaurants staying open, industrial processes not interrupted, etc.). These retained kWh energy sales and these avoided losses should be acknowledged as benefits to the economy -- California's economy in particular. In fact, annual outage damages to the state gross domestic product (g.d.p.) have been estimated at $8.1 billion.[127] Attributing grossly one third of this to PG&E results in damages of $2.7 billion annually. Because these damages fall to the economy at large, rather than a stricter interpretation of the AMI benefit and cost ledger, DRA has not dedicated resources to try and closely estimate the effects of PG&E's AMI proposal on the state g.d.p. For discussion purposes only DRA notes that a very conservative estimate of a 5 percent reduction in negative impacts to the state g.d.p. would translate to a benefit to ratepayers and the general economy of $133 million annually. This last figure is put forth for illustrative purposes only. It seeks to demonstrate the value to the state economy should a 5 percent in reduction in outage related damages to the economy be achieved through AMI.

III. CONCLUSION

DRA's proposed adjustments to T&D benefits lead to an increase of $5.9 million annually. $5.2 million in benefits achieved by PG&E would be due to

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5, lines 9 – 13.

[127] *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*, Lawrence
(Continued on next page)

improved design efficiency in the engineering and planning of the T&D grid. $0.7 million of the benefits would be derived from more efficient outage detection.

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Berkeley National Laboratory, Berkeley, CA, September, 2004, p. 28.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 11

DEMAND RESPONSE BENEFITS

WITNESS: THOMAS RENAGHAN

I. INTRODUCTION

This chapter presents DRA's and PG&E's estimated demand response benefits from PG&E's proposed Critical Peak Pricing ("CPP") proposal. Section II of this chapter summarizes DRA's and PG&E's findings and recommendations. Section III discusses the methodologies underlying PG&E's and DRA's results while concluding remarks are contained in Section IV.

II. SUMMARY AND CONCLUSIONS

PG&E argues that the introduction of CPP or time-varying rates will result in substantial reductions in peak load demand. These reductions in peak load demand, in turn, carry with it financial benefits. These financial benefits result from decreased energy and capacity payments "that flow from the changes in peak demand and energy use induced by the new tariffs." (Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-1). Rather than provide a single point estimate of demand reductions and the associated financial benefits from the introduction of time varying electric rates, PG&E constructed several scenarios designed to capture the likely impacts from the introduction of time varying electric rates. PG&E explains that it "considered four scenarios three of which feature opt-in deployment and one of which features opt-out deployment." (Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-1). Under the opt-in approach customers start with the existing rate and move to the new rates while under an opt-out format customers are placed on the new rates but retain the option of defaulting to the prior rate.

PG&E's preferred scenario, Scenario 1, involves aggressive marketing efforts and yields " a customer participation rate of 35 percent by the year 2011 for residential customers with central air conditioning ("CAC") and 27 percent for the larger segment of commercial and industrial ("C&I") that are targeted in the A-1 rate class." (Pacific Gas and Electric Company, Demand Response Impacts, June 15, 2004, p. 5-1). This scenario results in a 455 (MW) reduction in demand by the year 2011 and an associated financial benefit of $460 million. Future benefits of any new program will contain a degree of uncertainty. PG&E addresses this issue by using high and low price elasticities and participation rates under the base case scenario (Scenario 1). For example, under the base case scenario with lower price elasticities and participation rates, the MW demand reduction falls to 209 MW while the corresponding financial benefits falls to $210 million. Under the high price elasticity and high participation rate assumption, MW demand increases to 614 MW while the financial benefits rise to $622 million. Other scenarios are also considered under Scenario 1, such as the impact of higher CPP rates and lower capacity payments ($52 kWh vs. $85 kWh).

The remaining scenarios, 2, 3, and 4, are driven by different participation rate assumptions. Scenario 2, for example, is based on a "participation rate in 2011 of 30 percent for the targeted residential segment and 22 percent for the targeted C&I segment." (Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-1). Under this scenario MW demand reaches 388 MW and the associated financial benefit amounts to $382 million. Scenario 3 assumes a 40 percent participation rate for all customer classes. Under this scenario MW demand rises to 608 MW and the associated financial benefits rise to $581 million. Scenario 4, the opt-out deployment scenario, with 80 percent participation for all classes, yields the highest MW demand and financial benefits. Under this scenario demand reaches 1,217 MW and the associated financial benefits are $1,258 million.

The MW impacts and financial benefits under PG&E's five scenarios are summarized in Table 11-1.

Table 11-1

Pacific Gas and Electric Company
Demand Response Impacts and Benefits

Scenario	Title	MW Impact (2011)	Gross Financial Benefits ($ 000)
Base Case	Preferred	455	$ 460
1 Low	Preferred Low Case	209	$ 210
1 High	Preferred High Case	614	$ 622
1 (a)	Higher CPP Prices	529	$ 531
1 (b)	Medium C&I Opt-Out	591	$ 598
1 (c)	New Construction Opt-Out	538	$ 615
1 (d)	Partial Deployment	272	$ 282
1 (e)	Supply-Side Avoided Capacity	455	$ 279
2	Moderate Segmentation Marketing	388	$ 382
3	No Segmentation	608	$ 581
4	Opt-Out Deployment	1,217	$ 1,258

DRA's results are summarized in Table 11-2. Similar to PG&E, DRA developed measures of the MW impact and gross financial benefits from the introduction of time-varying or CPP rates. DRA, however, utilized assumptions that differed from PG&E's. Specifically, DRA altered PG&E's participation rates, capacity payment assumptions, level of on-peak and off-peak electric rates, capacity payments, and the discount rate. DRA's assumptions underlying the four scenarios reported in Table 11-2 are listed in Table 11-3.

DRA's optimistic participation rate assumption assumes that by 2011, the participation rate for residential customers with central air conditioning ("CAC") will reach 30 percent. For residential customers without CAC the participation rate is 5 percent. For the C&I classes, the A1-Small participation rate stands at 2 percent, while for the A1-Large, A6, A10, and E19V classes of service the optimistic participation rate reaches 27 percent. The 2011 participation rates are held constant for the period from 2012 through 2030.

Under DRA's pessimistic participation rates residential CAC customers achieve a participation rate of 9 percent in 2011. For the non-CAC residential customers the pessimistic scenario assumes a participation rate of 2 percent. For the C&I class, the A1-Small class, the participation rate also equals 2 percent. For the remaining C&I classes, A1-Large, A6, A10, and E19V the 2011 participation rate equals 24 percent. As in the case of the optimistic scenario, the 2011 participation rates are held constant from 2012 through 2003.

The basis for these optimistic and pessimistic participation scenarios are discussed in greater detail in Chapter 13, Participation in Critical Peak Pricing, of this report.

Table 12 – 2

DRA Demand Response Impacts and Benefits

Scenario	Title	MW Impact (2011)	Gross Financial Benefits ($ 000)
Optimistic (1A)	Optimistic Participation	404	$ 350
Pessimistic (1B)	Pessimistic Participation	173	$ 148
Optimistic (2A)	Optimistic Participation	404	$ 219
Scenario (2B)	Pessimistic Participation	173	$ 93
Scenario (3A)	Optimistic Participation	321	$ 309
Scenario (3B)	Pessimistic Participation	148	$ 136
Scenario (4A)	Optimistic Participation	321	$ 205
Scenario (4B)	Pessimistic Participation	148	$ 89

Table 11-3

DRA Demand Response Impact and Benefits Assumptions

Scenario	Participation Rate	Capacity Payments	Rates	Discount Factor
1 (A)	Optimistic	$ 85/Kw	PG&E Rates	8.79 percent
1 (B)	Pessimistic	$ 85/kW	PG&E Rates	8.79 percent
2 (A)	Optimistic	$ 52/kW	PG&E Rates	8.79 percent
2 (B)	Pessimistic	$ 52/kW	PG&E Rates	8.79 percent
3 (A)	Optimistic	$ 85/kW	DRA Rates	8.79 percent
3 (B)	Pessimistic	$ 85/kW	DRA Rates	8.79 percent
4 (A)	Optimistic	$ 52/kW	DRA Rates	8.79 percent
4 (B)	Pessimistic	$ 52/kW	DRA Rates	8.79 percent

The gross financial benefits of the proposed time-varying rate structure proposed by PG&E are also impacted by the assumed level of capacity payments. PG&E's preferred scenario, Scenario 1, assumed capacity payments of $85/kW. DRA's scenarios (1A), (1B), (3A), and (3B), are based on a capacity value of $85/kW. Lowering the assumed capacity value from $ 85/kW to $ 52/kW lowers the gross financial benefits from the introduction of time-varying electric rates. DRA's scenarios (2A), (2B), (4A), and (4B), are based on DRA's recommended capacity value of $52/kW. The basis for DRA's recommended capacity value is discussed in Chapter 15, Cost of Capacity, of this report.

The level of recommended on-peak and off-peak electric rates also influences MW demand and the associated financial benefits of a CPP rate structure. Utilizing PG&E's recommended on-peak and off-peak electric rates results in greater financial benefits. This is shown in DRA's scenarios (1A), (1B), (2A), and (2B). These scenarios assume that the Commission adopts PG&E's recommended on-peak and off-peak electric rates. In contrast, DRA's scenarios

(3A), (3B), (4A), and (4B) assume that DRA's on-peak and off-peak electric rates are adopted by the Commission. The difference in assumed electric rates is driven by what one assumes for the continued existence of AB1X legislation. This issue is discussed in greater detail in section IIIB of this chapter and in Chapter 3, Rate Design Policy, of this report.

All of DRA's scenarios reported in Table 11-2 rely upon a discount rate of 8.79 percent. PG&E, on the other hand, relied upon a discount rate of 7.60 percent. The justification for a higher discount rate is discussed in Chapter 14, Discount Rate, of this report.

III. METHODOLOGY

DRA and PG&E utilized similar methodologies to arrive at estimates of MW and gross financial benefits from the introduction of time-varying electric rates. The MW impact of the new rates is a function of a customer's average use, the change in usage from the new rates, the number of customers in the target population, and the number of customers participating in the new rate structure (participation rate). PG&E summarizes this relationship as:

(1) MW Impact = (Average kW use per customer in the 75 peak hours at the current rate) x (percent decrease in demand due to the higher rate) x (number of customers in the target population) x (participation rate percent)

The results shown in column (1), labeled MW impact, of Table 11-1 and Table 11-2 are based on the formula shown in equation (1). Gross revenue benefits are a function of the MW impact, avoided capacity costs, MW impact by rate period, and avoided energy costs. Gross revenue benefits can be expressed as:

(2) Total Benefits = [(MW Impact) x (Avoided Capacity Costs)] + [(MWh Impact by Rate Period) x (Avoided Energy Costs by Rate Period)]

The results shown in column (2), Gross Financial Benefits, in Table 11-1 and Table 11-2 are based on the formula shown in equation (2). To arrive at its estimates of demand response DRA followed PG&E's approach and utilized the relationships shown in equations (1) and (2).

PG&E calculates demand response benefits for residential customers on the E-1 tariff along with commercial and industrial customers on the A-1, A-6, A-10, and the E-19V tariffs. In the majority of PG&E's scenarios residential customers are segmented between customers with air conditioning and those without. For the C&I customers on the A-1 tariff large customers "equals all customers with average annual energy use exceeding 20,000 kilowatt-hour (kWh) and for whom the ratio of summer to spring average daily use ("ADU") exceeds 1.5; small equals all other customers in this rate class." (Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-3). DRA also used PG&E's segmentation.

A. <u>Residential Price Elasticity</u>

A key variable impacting demand response is the price elasticity of demand. Price elasticity of demand measures the percentage change in quantity demand to a percentage change in price. PG&E relies upon two measures of price elasticity of demand, the elasticity of substitution, and the daily price elasticity. PG&E explains that: "The elasticity of substitution measures the rate at which customers substitute critical peak for off-peak elasticity in response to changes in the prices of critical peak and off-peak electricity consumption…The daily price elasticity measures the response of daily electricity consumption to changes in the daily price of electricity that is brought about by the implementation of a time-varying rate." (Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-4). The residential price elasticities used in PG&E's analysis were derived from a set of econometrically estimated demand equations taken from the Statewide Pricing Pilot ("SPP") study.

The SPP econometric methodology involved jointly estimating two sets of equations. One equation measures the elasticity of substitution between the peak and off-peak periods as a function of the ratio of on-peak to off-peak prices, cooling degree days, and air conditioning saturation. The daily use equation models daily demand as a function of daily average prices, cooling degree days, and air conditioning saturation. Both equations include interaction terms between the relevant prices, cooling degree days, and air conditioning saturation.

To arrive at estimates of substitution and daily price elasticities for each of PG&E's four climate zones, PG&E coupled estimates of cooling degree days and air conditioning saturation rates with the estimated coefficients from the SPP study. PG&E's residential price elasticities are based on the SPP results for the inner summer period (July, August, and September). PG&E's estimated residential price elasticities, the elasticity of substitution and the daily price elasticity, are reported in Table 11-4.

Table 11-4

Pacific Gas and Electric Company

Residential Price Elasticities

Climate Zone	Day Type	Elasticity of Substitution	Daily Price Elasticity
T	Critical	-0.040	-0.039
	Weekday	-0.030	-0.042
	Weekend	n/a	-0.039
X	Critical	-0.086	-0.039
	Weekday	-0.056	-0.047
	Weekend	n/a	-0.021
S	Critical	-0.119	-0.038
	Weekday	-0.089	-0.047
	Weekend	n/a	-0.025
R	Critical	-0.123	-0.035
	Weekday	-0.098	-0.042
	Weekend	n/a	-0.022
System Average	Critical	-0.087	-0.038
	Weekday	-0.063	-0.045
	Weekend	n/a	-0.009

Source: Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-6.

The results reported in Table 11-3 show that demand is most price responsive in climate zones S and R, the inland climate zones, and least responsive in the coastal zones, X and T. This is explained by the relatively higher air conditioning saturation rates in zones S and R. Zones S and R have air conditioning saturation rates of 61.94 and 65.34 percent, respectively, while zones X and T are characterized by air conditioning saturation rates of 3.66 and 34.92 percent, respectively.

In developing the demand response impacts for the scenarios reported in Table 11-2, DRA relied upon the elasticities of substitution and daily price elasticities reported in Table 11-4.

B. <u>Commercial Price Elasticity</u>

Similar to the residential class of service, PG&E's estimates of demand response for the C&I classes of service are based on price elasticities taken from the SPP report. The commercial and industrial SPP models are similar in structure to the residential models. PG&E explains that: "The SPP analysis for the C&I sector used the same conceptual model specification as for the residential sector in that there were separate equations for rate-period shares and for daily energy use. However, price was not statistically significant in the daily energy use equation. Therefore, the only price-responsiveness measure underlying the C&I impact estimates is the elasticity of substitution." (**Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-8**). For customers with peak demands of less than 20kW (LT-20) the SPP study produces an elasticity of substitution of -0.045, while for peak demands between 20 kW and 200 kW (GT-20), the SPP study puts the elasticity of substitution at -0.069.

Since there is not a unique correspondence between PG&E's C&I rates (A-1, A-6, A-10, and E19V) to the LT-20 and GT-20 SPP segmentation, PG&E has to assign the commercial and industrial LT-20 and GT-20 elasticities of substitution to its C&I rate classes. Based on representative peak loads, PG&E assigned the

LT-20 elasticity of substation of -0.045 to the A-1 class and the GT-20 elasticity of substitution of -0.069 to the remaining C&I classes (A-6, A-10, and E-19V).

For purposes of its analysis of C&I demand responsiveness and benefits DRA has adopted the commercial and industrial elasticities of substitution reported by PG&E.

C. Electric Rates

1. Residential Rates

PG&E proposes to layer CPP rates (on-peak) and non-CPP rates (off-peak) on the existing residential tariff structure. PG&E proposes that: "For residential customers, the peak-period energy use on critical days is $0.60/kWh and the credit that applies to energy used in all other time periods is $0.03/kWh. In addition, volunteers for the dynamic rates receive a credit of $0.01/kWh on all usage in Tiers 3 and 4 regardless of time period." (**Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-10**). However, since PG&E has a tiered rate structure the average price faced by electric consumers is impacted by the climate zone and consumption in each tier. The CPP rate is applied to the average rate in each climate zone averaged across the tiers. PG&E explains: "For example, in Zone T, the Tier 1 price applies to the first 261 kWh, the Tier 2 price to the next 87 kWh, the Tier 3 price to the next 174 kWh, and the Tier 4 price to all energy use exceeding 521 kWh. The average customer in Zone T uses 366 kWh. Thus, the average price for the average Zone T customer equals $0.1225/kWh, since the customer has a monthly bill of $46.03 ($0.1143x261 + $0.1229x87 + $0.1756x28) and uses 376 kWh per month." (**Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-11**).

Table 11-5 reports average prices, averaged across all climate zones, which support PG&E's residential demand response analysis.

Table 11-5

PG&E Average Prices for Residential Tariffs

Rate	**Day Type**	**Average Price (cents/kWh)**	**Average Price (cents/kWh)**
		Peak	Off-Peak
Current	All	13.2	13.2
CPP-P	CPP	73.1	10.1
CPP-P	Non-CPP	10.1	10.1

Source: **Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-11**.

DRA's demand response results reported in Table 11-2, scenarios (1A), (1B), (2A), and (2B) relied upon PG&E's proposed CPP rate design.

DRA's demand response impacts reported in Table 11-2, scenarios (3A), (3B), (4A), and (4B) rely upon a different set of on-peak and off-peak electric rates. These rates are shown in Table 11-6.

Table 11-6

DRA Average Prices for Residential Tariffs

Rate	Day Type	Average Price (cents/kWh)	Average Price (cents/kWh)
		Peak	Off-Peak
Current	All	14.5	14.5
CPP-P	CPP	44.5	13.2
CPP-P	Non-CPP	13.2	13.2

Source: **Division of Ratepayer Advocates, Chapter 3, Rate Design Policy**.

DRA's on-peak electric rates are lower than PG&E's because DRA only apply CPP rates to the upper tiers of PG&E's residential tariffs. As explained in greater detail in DRA's Rate Design Policy testimony, this was done to insure that DRA's proposed CPP rates are compliant with the current AB1X legislation.

It should be noted, however, that DRA's demand response estimates under DRA's assumed rate design are problematical. The difficulty arises from the fact that DRA relied upon PG&E's residential price elasticities. These elasticities, in turn, were based on the results of the SPP study. The SPP study applied the on-peak ("CPP") and off-peak ("non-CPP") rates to all the residential tiers. In other words, it may be inappropriate to apply PG&E's residential price elasticities to a rate structure which restricts on-peak CPP rates to the upper tiers of PG&E's residential electric tariffs. In spite of this, DRA's results under scenarios (3A), (3B), (4A), and (4B), Table 11-2, are consistent with a recent comment by PG&E that: "While it is not practicable to extrapolate SPP results (which used prices that applied to participants' entire usage) to develop robust estimates of residential customer demand response under upper-tier-only price signals, it is clear that any such response would necessarily be much smaller that have been obtained under the SPP rate design." (Pacific Gas and Electric Company, Response to DRA Data Request, DR_DRA_002_05, August 4, 2005, p.2).

2. Commercial Rates

For the C&I classes of service PG&E recommends a CPP rate of $0.75/kWh. For customers on the A-1 and A-6 tariffs the off-peak credit equals $0.027/kWh with an "additional credit of $0.005/kWh for all off-peak energy use that occurs in the period between June 1 and September 30." (**Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-10).** For the A-10 and E19V tariffs PG&E recommends an off-peak charge of $0.023/kWh. Table 11-7 shows the C&I rates proposed by PG&E.

For purposes of its analysis DRA has adopted PG&E's C&I on-peak and off-peak electric rates reported in Table 11-7. In other words, the results reported in Table 11-2, under scenario's (3A), (3B), (4A), and (4B), reflect C&I demand response benefits under the rates set out in Table 11-7.

Table 11-7

Pacific Gas and Electric Company

C&I Energy and Average Rates

(Cents/kWh)

Rate	**Day Type**	**Price**	**A1**	**A1**	**A6**	**A6**	**A10**	**A10**	**E19V**	**E19V**
			Peak	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Current	All	Energy Rate	18.2	18.2	27.2	8.1	14.1	14.1	14.4	7.9
		Average Rate	18.9	18.9	27.5	8.4	16.8	16.8	34.2	8.9
CPP-P	CPP	Energy Rate	93.2	15.0	102.2	4.9	89.1	11.3	89.4	5.1
		Average Rate	93.9	15.7	102.5	5.2	91.8	14.0	109.2	6.1
	Non-CPP	Energy Rate	15.0	15.0	24.0	4.9	11.3	11.3	11.6	5.1
		Average Rate	15.7	15.7	24.3	5.2	14.0	14.0	31.4	6.1

Source: Pacific Gas and Electric Company, Demand Response Impacts and Benefits, June 15, 2004, p. 5-12.

IV. CONCLUSION

This chapter has presented DRA's and PG&E's analysis of the demand response benefits from the introduction of time-varying or CPP electric rates. PG&E concludes that under its preferred opt-in scenario that the demand response benefits of time varying electric rate structure are substantial. Under PG&E's preferred scenario the gross financial benefits of the new program amounts to $460 million. PG&E supplemented its base case with several alternative scenarios. The alternative scenarios are based on input assumptions which differ from those assumed in the base case. These scenarios involve changing the assumed values for such variables as the level of on-peak electric rates, capacity values, participation rates, and higher and lower price elasticities.

In developing its estimates of demand response benefits from the introduction of a CPP rate structure DRA followed a methodology that parallels PG&E's approach. DRA's demand response benefits differ from PG&E's primarily because DRA relied upon a different set of input assumptions than did PG&E. For example, DRA's participation rate assumptions, under both the optimistic and pessimistic scenarios, are lower than the participation rate assumptions embedded in PG&E's base case scenario. Consider, for example, DRA's scenarios (1A) and (1B). These scenarios utilized lower participation rates, a higher discount rate, but the same capacity payment and electric rates as PG&E. Under DRA's scenarios (1A) and (1B) the gross financial benefits are respectively, $350 million and $316 million. These estimates are substantially below PG&E gross financial benefit estimate of $460 million. Similarly, all of DRA's scenarios produce low estimates of the financial benefits of a time-varying electric rate structure. DRA attributes the lower estimates to the input assumptions employed by DRA. As described in this chapter, DRA's input assumptions are consistent with the findings of other DRA witnesses in this proceeding.

IV. ENDNOTES

1. Calculating the level of MW demand and gross financial benefits is based on a complicated model known as Price Response Impact Simulation Model ("PRISM"). PG&E provided DRA with a copy of its PRISM model. The formulas underlying the PRISM model are described in detail in Appendix 8 of the final SPP Report. (Impact Evaluation of the California Statewide Pricing Pilot, Charles River Associates, March 16, 2005, pp. 64-310 – 78-310).

2. The estimated coefficients underlying the estimated residential elasticities of substitution and daily price elasticity are contained in Appendix 16C of the final SPP Report. (Impact Evaluation of the California Statewide Pricing Pilot, Charles River Associates, March 16, 2005).

3. The estimated coefficients for the C&I models are shown in Appendix 17.a of the SPP final report. (Impact Evaluation of the California Statewide Pricing Pilot, Charles River Associates, March 16, 2005).

4. It should be noted that PG&E asserted that DRA's data request implicitly assumed that AB 1X precluded any changes to tier 1 and tier 2 rates. DRA's data request stated: "Please provide PG&E's best estimate of demand reductions comparable to those in presented in Table 5-6 assuming that AB 1X is interpreted to preclude any changes to tier 1 and 2 residential rates, including changes through credits and debits applied to existing rates. Please provide separate estimates assuming that all changes to tiers above tier 2 are applied on an opt-in and opt-out basis." PG&E responded in part that: "The question contains an assumption that AB 1X is interpreted to include any changes to tier 1 and 2 residential rates, including changes through credits and debits applied to existing rates. PG&E believes this assumption about AB 1X is legally incorrect and inaccurate. For this reason, although PG&E responds to the question with a discussion of residential customer demand response under a rate design with TOU and CPP price signals applied only to usage above Tier 2, PG&E does so for hypothetical purposes only and does not accept the interpretation of AB 1X

contained in the question." (Pacific Gas and Electric Company, Response to DRA Data Request, DR_DRA_002_05, August 4, 2005, p.1)

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 12

CONSERVATION THROUGH VOLTAGE REDUCTION

WITNESS: ROBERT KINOSIAN

I. INTRODUCTION AND SUMMARY

The AMI system proposed by PG&E has the ability to remotely read voltage as well as usage. With the information made available from this feature, voltage levels on the grid can be set with greater precision, lowering the amount of energy and capacity needed to serve customers. DRA recommends that the Commission require PG&E to utilize the AMI system to analyze voltage levels on PG&E's system and present the results in its next general rate case.

II. DISCUSSION

Conservation Voltage Reduction ("CVR") is a program that has been in place since 1976, wherein utilities keep the voltage levels on many of their distribution circuits between 114 and 120 volts, rather than the typical practice of keeping voltage between 114 and 126 volts. Reducing the voltage (while staying above the required minimum of 114 volts) has the result of decreasing the energy and capacity needed to serve customer demands. However, many of PG&E's circuits are not covered by CVR and it is unclear how many of the circuits that are in the program are compliant.

By using the AMI system's ability to remotely read voltage levels throughout the network, PG&E can monitor voltage levels on all of its circuits and evaluate which circuits have voltage levels set higher than necessary. The potential benefits of improving the implementation of CVR are large. When the Commission last considered PG&E's implementation of CVR, PG&E indicated that minor additional measures could decrease peak demand by as much as 50

MW (D.02-03-024, page 5, mimeo). A similar reduction from AMI would provide ratepayers with over $100 million in savings over the 20 year life of the AMI system.

PG&E's application does not address the ability of the AMI system to read voltage, or the potential to utilize that feature to more efficiently set voltages on its grid. To ensure that the potential reductions in demand are achieved and the resulting cost savings and greenhouse gas reductions are obtained, the Commission should require that PG&E use its AMI system to update and optimize the implementation of CVR on its circuits. DRA recommends that PG&E be required to present a study and proposals for expanding CVR in its next general rate case.

SECTION II.C

OTHER INPUTS TO DRA'S AMI ANALYSIS

DIVISION OF RATEPAYER ADVOCATES
CHAPTER 13

PARTICIPATION IN CRITICAL PEAK PRICING

WITNESS: EDGAR QUIROZ

I. INTRODUCTION

The purpose for this chapter is to evaluate PG&E's Critical Peak Pricing ("CPP") participation rate assumptions for residential and small commercial customers and to offer alternative assumptions that DRA believes are more realistic. This chapter also addresses the importance of effectively communicating with customers about CPP rates and programs in order to maximize participation rates.

II. BACKGROUND

There is some experience that shows that customers will participate in a time – based pricing program if information can be conveyed to them. The California Statewide Pricing Pilot ("SPP") was conducted during 2003 and 2004 to test customer interest. As part of the pilot, customers signed up for a CPP tariff. With the CPP rates, customers were charged a premium for electricity usage during peak periods when the utility was experiencing high prices in electricity markets and provided a modest discount during non- peak pricing periods.

The key to the SPP was that the utility notified its CPP customers, before each CPP event, enabling customers to respond by reducing energy usage during the CPP event periods. The experience with the SPP demonstrated that customers will respond to price signals if information about time-differentiated price signals can be communicated to them in a timely manner.

Many of the results are derived from the SPP, and assumptions used in that program form the basis for PG&E's projection of customer participation rates in its proposed CPP program.[128] Additional assumptions are based on customers' preferences that were identified as part of a commissioned survey.[129]

III. DISCUSSION

PG&E used several assumptions to create the data for the base year used in its analysis. Among them are:

1. As AMI is deployed, PG&E will offer a voluntary opt-in CPP rate to customers,
2. PG&E will segment its user population and market the CPP rate to customers with the greatest demand response potential based on climate zones and high summer electric bills,
3. AMI deployment will commence in the portion of PG&E's service territory with the greatest demand response potential.[130]

A. Customer Classes to Be Targeted

PG&E identifies the customer classes that should be encouraged to participate in the CPP program. These groups break down into two main classes:

1. Residential customers with air conditioning located in the hot, inland areas, and
2. Medium commercial customers (including 200 kWh A-1 customers with a 50 percent more usage pattern in the summer months relative to the spring months and all A-6, A-10 and E-19 tariff rate voluntary customers).[131]

B. CPRRMD Survey Interpretations

As part of a specific PG&E market research effort, the Company commissioned Momentum Market Intelligence (Momentum), to conduct a survey to develop a profile of

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[128] A.05-06-028, pg 5

[129] "Customer Preference Research on Rates and Metering Data", (CPRRMD), Momentum Market Intelligence, May 2005

[130] CPRRMD, pg. 9

[131] A.05-06-028, Exhibit 4, pg. 2-4

likely participants in a proposed CPP program. The survey results and recommendations are contained in the report," Customer Preference Research on Rates and Metering Data" ("CPRRMD"). Among the areas measured were: impact of customer awareness of tariffs, customer perceptions of participation benefits vs. complexities, customer understanding of options (including hardware options and profiling of those customers who chose to "opt-in"). The CPRRMD survey results provided the basis for much of the CPP participation rate projections.

DRA reviewed the results and recommendations derived from the survey work. The survey appears to be quite detailed and comprehensive with respect to researching potential customer responses to CPP participation. However, it is not the purpose of this testimony to determine the validity of the survey's methodologies and results. Nevertheless, certain limitations of the survey should be understood. First, the survey was confined to a very small sample group that would be part of the larger customer target group for any CPP offering. Also, while many customers indicated a willingness or interest in participating, the survey authors point out that a percentage of respondents may have a tendency to "typically overstate interest." While the survey results might be of some value in projecting participation rates, reliance on this survey may result in overly optimistic projections.

The Electric Power Research Institute ("EPRI") funded an insightful study by the Research Triangle Institute ("RTI")[132] on customer preferences. The RTI study investigated customer preferences, given a broad selection of electricity pricing plans; 70 percent preferred fixed rates, 10 percent seasonal rates, 20 percent time-of-use ("TOU"). The study reported that those who preferred TOU rates tended to have higher incomes, be younger and live alone or live with unrelated individuals. The survey sample size was 363 active residential accounts in eight large utilities in the Eastern half of the United States.

[132] Predicting Customer Choices among Electricity Pricing Options, Vol. 2: EPRI Report TR-108864, Nov. 1998, pgs. 6-8 – 6-11

For small C&I customers, 89 percent preferred fixed rates, 8 percent seasonal and 6 percent TOU in a sample of 499 users. For the medium C&I, the sample size was 403 customers and the results were: 81 percent preferred fixed rates, 10 percent seasonal, 7 percent TOU and 2 percent hourly. Those medium C&I customers who most preferred TOU rates were likely to be government organizations.

C. Areas of Greatest Demand Response Deployment

Most customers identified as good candidates for voluntary residential CPP rates share curtain characteristics. Typically, the CPRRMD survey identified likely participants as having homes with 5 or more bedrooms, having high summer electric bills over $121 per month, living in climate zones S& R (PG&E designations for inland Central Valley locations) and report that they can adapt electricity usage rate to a CPP rate.[133]

For customers identified as likely commercial and industrial ("C&I") CPP rate takers, the survey identified other characteristics. These customers have 10-99 employees, have automatic lights, use air conditioning moderately during peak hours, have high summer electric bills over $800 per month, and indicate adaptability to a CPP rate.

D. CPP Rate Participation Evolution and Five Year Plan

In its application, PG&E provided a table, Table 2-2 on pg 2-8, Exhibit 4 that shows its projected CPP rate participation ramp-up percentages by customer segment and year. The company assumed a yearly growth rate for each year during the proposed program lifetime of 5 percent until 2011--when a maximum participation rate of 35 percent is projected to be achieved. The exception is for residential customers without air conditioning whose participation rate is assumed to remain static.

DRA believes these projections may be achievable, but are highly optimistic. These ramp-up rates assume that the target class in residential and small commercial will

[133] CPRRMD, p. 3

respond to the CPP tariff in increasing numbers and that ongoing response will continue an even, yearly growth over the five year program life with no attrition (customers switching back to non-CPP rates. DRA does not agree with this viewpoint.

DRA provides alternative projections, which it believes are more realistic, in two tables. Table 13-1 assumes a lower initial threshold of participation for residential customers with air conditioning and a 5 percent lower per year ramp-up for each year of the program. The assumption here is less interest on the part of the residential customer with air conditioning. The commercial class rate remains the same in this scenario. The reason for this was that commercial customers are probably more familiar with TOU rates than are residential customers.

Table 13-1
PG&E CPP Rate Participation
Ramp_Up Assumptions - Mid Rates
By Population Segment And Year (%)

Segment	**2006**	**2007**	**2008**	**2009**	**2010**	**2011-2026**
Residential with Air Conditioning	5	10	15	20	25	30
Residential without Air Conditioning	2	2	2	2	2	2
A-1 small	2	2	2	2	2	2
A-1 Large	2	7	17	22	27	27
A-6	2	7	17	22	27	27
A-10	2	7	17	22	27	27
E-19V	2	7	17	22	27	27

Table 13-2 uses a different set of assumptions. This scenario attempts to capture the results to date of the only ongoing utility CPP program, the one undertaken by Gulf Power and identified as the “GoodCents-Select” program. A more detailed discussion is contained in Chapter 3 of DRA’s testimony. That program has an ultimate target response of approximately 11 percent participation. It should be noted that the Gulf Power program is for residential customers only. The program has had a lower percentage of residential customers that are CPP participants. DRA based its participation assumptions on Gulf Power's experience. Customers with air-conditioning were assumed to start at 1 percent penetration and grow at approximately 1-1.5 percent per year.

Table 13-2
PG&E CPP Rate Participation
Ramp_Up Assumptions Low rates (reflect Gulf Power Res.Program)
By Population Segment And Year (%)

Segment	2006	2007	2008	2009	2010	2011-2026
Residential with Air Conditioning	1	2.5	3.5	4.5	9	9
Residential without Air Conditioning	2	2	2	2	2	2
A-1 small	2	2	2	2	2	2
A-1 Large	2	4	14	19	24	24
A-6	2	4	14	19	24	24
A-10	2	4	14	19	24	24
E-19V	2	4	14	19	24	24

E. Comparisons and Contrasts with Other Utility Experiences

In its testimony, PG&E cites several examples of other utilities' experiences with TOU programs.[134] Almost all of the historic TOU rates were based on fixed on-peak periods that are defined well in advance in the tariff, which is not the case with critical peak pricing events. Only one of the examples was based on trials that had critical peak pricing tariffs. The only program that approximates the CPP participation is the Gulf Power program described and discussed in Chapter 3 of the DRA testimony.

This experience shows that customer participation has been significantly lower than PG&E is projecting. DRA believes that projected participation rates based on the experience of Gulf Power are more realistic than those used by PG&E.

[134] PGE Exhibit 4, p. 3-6, 3-10

F. Proposed Marketing Strategy for Achieving Anticipated Participation Rates

PG&E's application and program strategy regarding customer information assume that the meter is the significant interface between the customer and the utility. A detailed discussion on some of the different communications options is further referenced in Chapter 2 of the DRA testimony.

The application does not address load control techniques. PG&E could make load control devices such as programmable smart thermostats, gateways and others available to help customers respond. Chapter 1 further discusses the policy implications of offering customers load control choices and Chapter 2 further discusses various load control technical options.

G. Marketing Incentives and Costs

In its discussion on the CPRRMD survey results, PG&E interprets two key points:

- More customers are likely to sign up for time-differentiated rates if there is an opportunity to save money and,
- As customer CPP rate awareness increases, acceptance rates also increase.

PG&E also reports that according to the CPRRMD survey, other factors that seem to encourage customer participation include rebates and rate guarantees/bill protection for the first year of participation[135].

The survey did not explicitly address the issue of customer attrition. Attrition is a significant concern, especially since the projected marketing costs to recruit customers to CPP rates is considerable. The company has identified in exhibit 4, pg 3-19, Table 3-1, marketing costs ranging from approximately $38 - $55 million for customer acquisition expenses. These projected marketing costs do not appear to include any costs to retain participants. Previous experience, such as Gulf Power's and Puget Sound's programs have shown that attrition rates can significantly increase after years 2 and 3. Some reasons for this are that either energy savings benefits fail to meet customer expectations,

[135] CPRRMD, pg 3

the cost to participate is too high, or program is perceived to more cumbersome. The SPP pilot in California was not undertaken for a long enough period (2003-2004) to provide any useful information about long-term customer attrition.

It is DRA's opinion that PG&E should be directed to report on the costs and effectiveness of its CPP marketing strategies after three years and the Commission should consider whether changes are warranted. Among other things, the Commission may want to consider, at that review point, if other measures are needed to retain those customers that have been successfully recruited during the first few years.

III. CONCLUSION

PG&E's assumptions used to project potential participation by residential and C&I customers, in time-differentiated rate structures such as CPP, are based on results from the SPP and the CPRRMD survey results published in June 2005.

DRA believes that PG&E assumptions regarding likely CPP participants, defined by customer classes, are probably correct. However, the company's projected initial participation numbers and ramp-up rates appear optimistic compared to previous utility experiences.

DRA offers two alternative participation rate projections; one with a slightly lower number of initial participants and slightly lower yearly growth rates, and a second one with a significantly lower growth rate. The basis for the lower growth rate projections are previous utility experience with CPP rates.

DRA recognizes that many variables can impact participation. Customer perceptions influenced by such things as effective communication of CPP program benefits to the intended target customer and the ease of understanding any CPP tariff for different targeted classes. The same factors will probably prove to be important in maintaining and sustaining continued customer interest and participation.

DRA also believes that the use of load control devices and communication methods could positively impact the numbers of participants over the initial five year program life. The PG&E application has neither fully explored nor integrated this option as part of the company's overall strategy for the five year program rollout.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 14

DISCOUNT RATE

WITNESS: ROBERT KINOSIAN

I. INTRODUCTION AND SUMMARY

DRA recommends that a discount rate of 8.79 percent, equal to PG&E's after tax weighted cost of capital adopted in D.05-12-043, be used to calculate the net present value of the costs and benefits of PG&E's AMI proposal. Using the after tax weighted cost of capital as specified in D.05-12-043 is consistent with the approach used in other Commission proceedings. PG&E proposes to instead use a lower discount rate that is derived in a manner that is different than typically used by the Commission for these purposes (PG&E-5, page 1-13).

Not only is DRA's discount rate more consistent with Commission practices, it more reasonably reflects the actual costs borne by ratepayers for the use of capital over time, and more accurately reflects the risks or this investment than does PG&E's proposed discount rate. PG&E's proposed value also fails to reflect the most recent changes to PG&E's cost of capital adopted in D.05-12-043 and is therefore out of date, and relies on an inconsistent approach regarding the impact of taxes on the utilities' cost of capital (including the tax benefit of debt costs while not reflecting the tax burden of return on equity costs).

Using the more appropriate 8.79 percent discount rate results in a reduction in the present value of the net savings forecast for the AMI proposal compared to using PG&E's discount rate, of approximately $100 million. This is because the majority of costs for the AMI project occur in the early years of the project's life, while the majority of the benefits occur in the later years. A higher discount rate results in a greater reduction in the present value of costs and benefits in the distant future than costs and benefits in the near term.

DIVISION OF RATEPAYER ADVOCATES

CHAPTER 15

COST OF CAPACITY

WITNESS: CHERIE CHAN

I. INTRODUCTION

DRA finds PG&E's use of a $52/kW-yr capacity value to be reasonable for estimating demand response benefits and initially setting CPP rates. DRA agrees with PG&E that the value of additional energy and ancillary value can be subtracted from the annualized cost of a combustion turbine ("CT") proxy to derive a pure capacity value. With respect to the Commission's suggestion to use an $85/kW-yr combustion turbine proxy price, DRA finds that this price would overstate the value to ratepayers of demand reductions resulting from implementation of AMI for a variety of reasons. DRA also notes that the Commission will over time consider "further improvements in the avoided costs adopted . . . for the valuation of . . . resource options that reduce peak (in particular, critical peak) demand."[136]

II. DISCUSSION

A. PG&E's Position

In its testimony, PG&E points to two primary supply-side proxies as estimates for avoided capacity values. The first, $85/kW-yr per the Commission's ruling,[137]references the levelized cost of the California Energy Commission's report of a Combustion Turbine

[136] Administrative Law Judge's Ruling on Scope and Schedule for the 2006 Update to Avoided Costs and E3 Calculator Directed by Decision 05-09-043, page 1.

[137] CPUC, Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, Rulemaking 02-06-001, July 21, 2004.

Proxy value of $80/kw-yr in expenses.[138] The second, 52/kw-yr, represents PG&E's proposed avoided net capacity cost, which consists of:

Going forward fixed cost of a combustion turbine	$94/kW-yr
(less) Expected net energy benefit of the energy generated	$42/kW-yr
Avoided net capacity cost.	$52/kW-yr

The expected net energy benefit is essentially the profit PG&E projects by selling the resulting energy generated when a combustion turbine is used to generate electricity.

B. Avoided Cost in Other Proceedings

Recently, PG&E, DRA, and other parties have submitted testimony on Qualifying Facilities ("QF") and Pricing Issues[139]. Depending on the status and type of contract, some parallels can be drawn between capacity values for some QF and demand response technologies such as AMI.

In PG&E's QF testimony, PG&E recommends a capacity value of approximately $10/kW-yr as the going forward fixed cost minus the net energy benefits of existing generation, instead of the $87/kW-yr to $110/kW-yr for new generation.[140] The Utility Reform Network (TURN) asserts that the starting CT proxy price should be $61/kW-yr, not $85/kW-yr, by correcting erroneous financial assumptions. TURN indicates that the $61/kW-yr capacity value could be reduced further to account for the energy and ancillary services benefits of CT's, resulting in an amount well below $61/kW-yr.

C. Other Parties

Though not a part of the record in this proceeding, SCE's testimony in its AMI Business Case Filing is relevant. This is because the Commission's goal is to use uniform avoided cost in different proceedings. In D.05-09-043, the Commission stated that it intends to "develop a common E3 calculator for use by all implementers, in order

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[138] "Comparative Cost of California Central Station Electricity Generation Technologies, California Energy Commission, 100-03-001, August 2003.

[139] Rulemaking 04-04-003 and 04-04-025.

[140] Exhibit PG&E-2 (Technology Acquisition Costs and AMI Operations), June 16, 2005, Chapter 3, p. 43 and PG&E Rebuttal Testimony on QF Policy and Pricing Issues Chapter 3, p. 43, October 28, 2005.

to facilitate an apples-to-apples comparison of projected savings and cost-effectiveness calculations”[141] related to avoided costs. In its testimony, SCE also utilizes the commission’s recommended $85 capacity value, and then suggests “value adjustments.” In the case of the scenario modeled in SCE’s analysis, a Critical Peak Pricing (“CPP”) event could only be called 12 times per summer period for up to five hours per event. Because a CPP event can only be called a set number of times per year, a CPP program does not have the full dispatchabilty of a CT, and thus has a lower capacity value. In an especially constrained year, SCE would be unable to call a thirteenth CPP event. Furthermore, CPP events are only called during the summer season in SCE’s rate design scenario. Therefore, the capacity value must be decreased proportionally with the probability that there will be a loss of load during the non-summer season. With these value adjustments, which PG&E does not discuss in its testimony, SCE arrives at a marginal capacity value of $52.70/kW-yr.

TURN, SCE and PG&E have used different factors to reduce the capacity value recommended by the commission to very similar levels. Combining these adjustments would result in a capacity value for AMI that is considerably lower than PG&E’s proposed value of $52/kW-yr. At this time, DRA does not advocate combining PG&E’s energy and ancillary services adjustments and SCE’s LOLP adjustment methodologies to arrive at an even lower capacity value for the business case.

III. RECOMMENDATIONS AND CONCLUSION

DRA readily acknowledges that estimates of the deferred capacity value of AMI will continue to be debated beyond the timeframe allowed in this proceeding. DRA looks forward to the results of discussions raised in proceeding 04-04-025, possibly by the first half of this year. In the meantime, DRA finds PG&E’s proposal of the $52/kW-yr deferred capacity value of AMI to be reasonable.

[141] D0509043 Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 - Phase 1 Issues, Proceedings: A0506004; A0506011; A0506015; A0506016.

<u>ATTACHMENT A</u>

STATEMENT OF WITNESSES QUALIFICATIONS

STATEMENT OF WITNESSES QUALIFICATIONS

ROBERT KINOSIAN

Q.1. Please state your name and business address.

A.1. My name is Robert Kinosian. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission (COMMISSION) in its Office of Ratepayer Advocates as a Policy Advisor.

Q.3. Please state your educational background and experience.

A.3. I received a B.S. In Mechanical Engineering from the University of California at Berkeley in 1983, graduating with honors. I am a licensed mechanical engineer in the state of California. I joined the staff of the COMMISSION in May 1984. I have testified in numerous proceedings before the COMMISSION, the State Legislature and the California Energy Commission. A few of the issues I have addressed include:

Funding of conservation programs; Penalties for favoritism and high costs regarding utility contracts with affiliated QFs; Penalties for overpayments regarding inter-utility power purchase contracts; Cost-effectiveness and ratemaking for the San Onofre, Palo Verde, Diablo Canyon and Humboldt nuclear power plants; Use and issuance of rate reduction bonds; Gain on sale of utility plant; Biases in favor of fossil fuels in resource procurement procedures; Calculation of transition costs; QF contract administration; Retirement of the SONGS 1 nuclear power plant.

In addition, I was the energy advisor to the President of the Commission from 2001 through 2003, working on a variety of energy issues including: legislative work, such as editing, commenting and lobbying on RPS legislation; drafting decisions, such as the decision approving five year fixed energy prices for QFs; and, resource planning work, such as initiating the COMMISSION resource planning proceeding and coordinating efforts with the ISO, DWR and the CEC. I also served as a special assistant to the Executive Director overseeing PG&E's bankruptcy proceeding, and served on the State task force renegotiating DWR contracts.

STATEMENT OF WITNESSES QUALIFICATIONS

SCARLETT C. LIANG-UEJIO

Q.1. Please state your name and business address.

A.1. My name is Scarlett Liang-Uejio. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Electricity Resources and Pricing Branch of Division of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Science degree in Mechanical Engineering from South China University of Technology in 1983. I also received a Masters degree in Mechanical Engineering from University of California, Davis in 1989. I joined the Commission in September 1989. I have worked on energy matters and electric ratemaking since 1990.

I was DRA's witness on Critical Peak Pricing and electric utility costs in various Commission ratemaking proceedings including the Default CPP for Large Customers, Phase I, Pacific Electric and Gas Company's 2003 General Rate Case, Phase II, Southern California Edison's 2003 GRC, Phase II, and PG&E's Electric Restructuring Cost Account proceedings.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapters 3 and 5 of DRA's prepared testimony.

STATEMENT OF WITNESSES QUALIFICATIONS

Ralph E. Abbott

Q.1. Please state your name and business address.

A.1. My Name is Ralph E. Abbott, and my business address is Plexus Research, Inc., 629 Massachusetts Avenue, Boxborough, MA 01719.

Q.2. By whom are you employed and in what capacity?

A.2. I am President of Plexus Research, Inc. and a co-founder of that consulting firm. Since 1985 the firm has specialized in advanced customer technology applications for energy utilities, prominently including metering, AMR and AMI. I am serving the Commission-DRA as a consultant and witness.

Q.3. Please describe your education and professional experience.

A.3. I received my Bachelors in Mechanical Engineering from Bucknell University of Lewisburg, PA in 1962 and attended the Graduate Business School of the University of San Francisco between 1965 and 1967. I am a Registered Professional Engineer and have been a Senior Member of the Power Engineering Society of the IEEE. I am a charter member of the Automatic Meter Reading Association and am a member of the Technical Advisory Committees of the DistribuTECH Symposium and the Metering Americas Conference. I have been a radio amateur for 50 years. I have previously provided expert testimony in PUC proceedings in the states of Wisconsin, North Carolina, Massachusetts and Connecticut. I am a frequent speaker at national conferences and typically author at least four published papers or articles in utility industry publications each year.

I began my career with Bailey Meter Company as an application engineer, specializing in process control and utility boiler and nuclear reactor control systems. While with Bailey Meter Company I was based in San Francisco. From 1968 through mid 1973 I was the Director of Sales for two prominent aerospace instrumentation companies, Spar Aerospace and Adcole Corp. In 1973 I joined

STATEMENT OF WITNESSES QUALIFICATIONS

Ralph E. Abbott
(CONTINUED)

American Science and Engineering of Cambridge, MA, and from 1973 through 1980 served as Vice President of Utility Systems. My division, under contracts with General Public Utilities, the Federal Energy Administration and the United States Department of Energy, developed and commercialized a two-way automatic meter reading system using powerline communication techniques capable of TOU, demand and interval metering, load control and dynamic rates. The system was commercially deployed by more than 30 utilities. In 1980 I joined Vedette Energy Research of Thousand Oaks, CA as a Vice President guiding the development commercialization of a utility alerting, notification and load control system using the sub carrier of commercial broadcast radio. In 1984 the technology and assets of Vedette were acquired by ABB, and were deployed in a number of major utilities. In 1985 I co-founded the consulting firm; Plexus Research, Inc. Plexus serves energy utilities worldwide, institutional clients including EPRI, NRECA, NARUC, EEI, and suppliers of advanced customer technology solutions.

As President of Plexus, I am involved daily in utility AMR and AMI applications beginning with preliminary needs assessments, through development of business cases, system specifications, RFI and RFP development, installation strategy, vendor and technology assessment, contract development, project definition and test. Within the past five years Plexus utility clients have included: Progress Energy, Xcel Energy, Until, Central Vermont Public Service, JEA (formerly Jacksonville Electric Authority), National Grid, Sacramento Municipal Utility District, and IPALCO. Plexus is currently running AMI projects for Jamaica Public Service and the City of Seattle, Washington.

Plexus has provided consulting services in other aspects of utility customer technologies, including load control, home automation and commercial energy automation systems, thermal storage, residential gateways, sub metering, BPL (broadband communication on power lines) and advanced electric end uses. I have participated in the development of authoritative industry guides for EPRI, NARUC, EEI and NRECA on BPL, AMI, Load Control and related topics. The firm has provided services to PG&E, SCE and Sempra, but not in the field of advanced metering systems.

Q.4. What is your responsibility in this proceeding?

A.4. I am sponsoring Chapter 2 entitled Functionality Criteria, Technology, and Vendor Selection issues.

STATEMENT OF WITNESSES QUALIFICATIONS

ANTHONY FEST

Q.1. Please state your name and address.

A.1. My name is Anthony Fest. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed as a Public Utility Regulatory Analyst in the Energy Cost of Service Branch of the Division of Ratepayer Advocates at the California Public Utilities Commission. I joined the COMMISSION staff in 1997, working in the Energy Division. I transferred to DRA in 2000.

Q.3. Please summarize your educational and professional experience.

A.3. I hold a Bachelor of Arts degree in Economics from California State University, Fullerton. I have held staff positions at the FERC, the Maryland Public Service Commission, the Nevada Public Service Commission and Southwest Gas Corporation. I have worked on matters of cost-of-service, allocation and rates design, and other regulatory issues.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am responsible for Chapter 4.

STATEMENT OF WITNESSES QUALIFICATIONS

LOUIS IRWIN

Q.1. Please state your name and business address.

A.1. My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Division of Ratepayers Advocates.

Q.3. Please describe your educational and professional experience.

A.3. I have a Master of Arts in Economics from the University of Colorado at Boulder and a Master of Public Administration from the JFK School of Government. Both degrees included coursework in finance and economics that I find relevant to this case. Since joining DRA in 1999, I have worked on curtailment policy, distributed generation, congestion pricing and under grounding issues (regarding distribution wires) prior to working on this case. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates, a specialist in these areas.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring DRA's testimony associated with Chapters 7, 8 and 10.

Q.5. Does this complete your testimony?

A.5. Yes, it does.

STATEMENT OF WITNESSES QUALIFICATIONS

CHERIE CHAN

Q.1. Please state your name and business address.

A.1. My name is Cherie Chan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Resources and Pricing Branch of Office of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I also hold a certificate in Project Management from the University of California, Extension.

I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities and ESP's as a Project Manager and Product Engineer. I worked on several projects including the technical and project-level implementation of internet-based Curtailment and Bill Estimation programs in California, and integrated interval-data management, billing, and settlements systems in Ontario, Canada. I was also involved with the E-VEE interval data project at PG&E by managing, testing, and installing some software upgrades, rewriting the User Manual, and developing Use-Case designs for the ABB software development team.

CHERIE CHAN

I joined the Commission in June, 2005, and sponsored chapters on "Marginal Distribution Costs" and "Marginal Generation Costs" of ORA's prepared testimony in Southern California Edison's 2006 GRC Phase 2 Filing.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapter Nos. 6 and 15, "Information Technology Costs" and "Cost of Capacity" of ORA's prepared testimony.

STATEMENT OF WITNESSES QUALIFICATIONS

Marshal B. Enderby

Q.1. Please state your name and address.

A.1. My name is Marshal B. Enderby. My business address is 505 Van Ness Avenue, San Francisco, California.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst IV in the Division of Ratepayer Advocate's Energy Cost of Service and Natural Gas Branch.

Q.3. Please briefly describe your educational background and work experience.

A.3. I graduated from Reed College with a BA in Liberal Arts and Economics and later from the University of Washington (Seattle) with an MA in Economics. Subsequently I taught economics and statistics courses at a private college and worked as an economic analyst for a Federal agency. Since joining the Commission in 1977, I have worked in various regulatory areas, prepared various reports and testified numerous times as an expert witness before the Commission.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am responsible for the preparation of "Chapter 10—Meter Reading Benefits," in DRA's testimony for Application No. 05-06-028.

Q.5. Does that complete your prepared testimony?

A.5. Yes, it does.

STATEMENT OF WITNESSES QUALIFICATIONS

Thomas Renaghan

Q.1 Please state your name and address.

A.1 My name is Thomas Renaghan. My business address is the State Building, 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst IV.

Q.3 Will you please state briefly your educational background and work experience.

A.3 I hold a Bachelor of Arts in Economics from California State University, Hayward and a PhD in Economics from the University of California, Davis. I have been employed with the Commission since January 1984. My experience with the Commission has been in the areas of inflation forecasting, gas sales forecasting, benchmarking studies, and performance based ratemaking.

Q.4. What are your areas of responsibility in this proceeding?

A.4 I am responsible for Chapter 11.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.

STATEMENT OF WITNESSES QUALIFICATIONS

ED QUIROZ

Q.1. Please state your name and business address.

A.1. My name is Ed Quiroz. My business address is 505 Van Ness Avenue, San Francisco, California 94102

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utility Regulatory Analyst in the Office of Ratepayer Advocates.

Q.3. Briefly describe your educational background and professional experience.

A.3. I have a B. S. in architecture from the University of California at Berkeley. I joined the California Public Utilities Commission in 1983. During my tenure, I have worked on various gas, electric, and telephone matters. I have also participated in previous metering efforts, standards development and meter data applications. I have previously testified before the Commission on my recommendations.

Q.4. What Chapter is your testimony sponsoring in this proceeding?

A.4. I am sponsoring Chapter 13 – Participation in Critical Peak Pricing Programs.

Q.5. Was the testimony in Chapter 13 prepared by you or under your direction?

A.5. Yes, it was.

Q.6. Does this complete your testimony at this time?

A.6. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document "**TESTIMONY ON PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR AUTHORITY TO INCREASE REVENUE REQUIREMENTS TO RECOVER THE COSTS TO DEPLOY AN ADVANCED METERING INFRASTRUCTURE**" in Application No.05-06-028.

A copy was served as follows:

[X] **BY E-MAIL**: I sent a true copy via e-mail to all known parties of record who have provided e-mail addresses.

[X] **BY HAND DELIVERY**: I hand delivered a true copy to the Administrative Law Judge Michel Cooke, and Assigned Commissioner Michael Peeve.

[X] **BY MAIL**: I sent a true copy via fist class mail of the unredacted document to PG&E.

[X] **BY HAND DELIVERY**: I hand delivered a true copy of the unredacted document to the Administrative Law Judge Michel Cooke, and Assigned Commissioner Michael Peeve.

Executed in San Francisco, California, on January 18, 2006.

Christopher J. Blunt
Project Coordinator, A.05-06-028