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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Upgrade its SmartMeter™ Program (U 39 E).	Application 07-12-009 (Filed December 12, 2007)

OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES

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In accordance with Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the Division of Ratepayer Advocates (DRA) hereby files this Opening Brief.

I. General Policy Issues

a. Introduction

To date, Pacific Gas and Electric Company's (PG&E) AMI project has suffered from serious complications. There are many indications that PG&E is now choosing to address these problems by presenting the Commission with a new AMI application disguised as an "upgrade." PG&E's motivations arguably have a more questionable basis than the apparently benign need to enhance its present system due to technological advances. Rather, there are strong indications that PG&E's first AMI deployment is indeed in serious trouble. A few examples should set the tone for what should be a very circumspect review of many of PG&E's claims in this Application:

- PG&E has already spent one third of its initial $1.7 billion authorization, but has only activated 2% of electric meters;
- PG&E has exhausted $70 million of its $88 million Program Management budget when the project is barely off the ground and already in need of change;

- PG&E's information technology (IT) budget is already 33% *over* budget. But that should come as no surprise since history shows that PG&E has repeatedly failed in the area of IT.

Despite the fact that the Commission has clearly given California's utilities the green light to proceed with AMI deployment, it needs to send a message to all utilities that although the sky is the limit in terms of possibilities, the reality is that ratepayers today can ill afford to spend their hard earned money fixing problems that they did not cause. It is well known now that DRA supports AMI, but only if the utilities' business cases can reasonably assure the Commission that they will be cost beneficial. DRA is opposed to the approval of projects that are based on amorphous benefits predictions that are untested and only theoretically possible. Unfortunately, PG&E's original case has proven to be just that.

DRA would like the Commission to apply some procedural restraint on what PG&E apparently perceives to be a runaway AMI gravy train. It is respectfully submitted that a Decision approving this cost-ineffective upgrade could lead to a staggering waste of ratepayer money. Very little, in terms of PG&E's AMI performance to date, causes DRA to have much confidence in PG&E. The jury is still out as to when, or if, its ratepayers will ever see the benefits identified in PG&E's original, or this upgrade proposal, that would justify its enormous cost. DRA does not find this Upgrade Application to be cost-effective, and therefore respectfully recommends that the Commission reject it.

b. The Commission needs to clearly define how PG&E should have presented its cost-benefit business case in this proceeding, as well as in future AMI upgrade Applications

DRA has serious due process concerns regarding how PG&E has presented this case. DRA would like to highlight this issue as a policy question for the Commission to resolve. As this proceeding has evolved, it has become clear that PG&E and DRA have a fundamental dispute as to what the meaning of an "upgrade," or "incremental" business case is, in terms of analyzing the costs and benefits of the “upgrade application.” The issue concerns the differing approaches that should be taken when PG&E files its upgrade applications. They are, on the one hand, whether to evaluate PG&E’s upgrade request by *including* or *excluding* costs and benefits evaluated in A.05-06-028, its original AMI Application; and on the other, whether it would have been preferable for PG&E to file this application on a “total project” basis.

How such a request should be presented is critical in order to ensure that all parties are provided with a fair and equal opportunity to develop their analysis. DRA and other interveners need to understand from the beginning what is expected of them in terms of the kind of analysis they are to perform. That has proven very difficult to do. PG&E, in the course of this proceeding, has at one time or another, flip-flopped as to which approach it wanted applied to its business case, depending on how vulnerable it believed its proposal was. It is unacceptable and fundamentally unfair to ratepayers to continually change the standard of review when interveners find the benefits come up short under a given standard.

In its rebuttal testimony, served only two weeks before hearings, PG&E posited the novel notion that, when the total cost of its request is evaluated, it is comparable to those of Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) on a per meter basis (Ex. 8, page 3-18). First, this is a highly debatable assertion, as is discussed below in Section IV.A. Second, it was unexpected, as PG&E had initially presented its analysis on an incremental basis that excluded the costs and benefits adopted in A.05-06-028.

PG&E’s Upgrade Application and testimony referred to its latest proposal as an “upgrade” to its original business case that was approved by the Commission in D.06-07-027. The entire basis upon which it presented its case was that the cost of the new system – that is, the solid state meters, integrated service switch and home area network (HAN), together with all the other identified costs of the upgrade – be less than the estimated benefits of the upgrade proposal. When DRA served its testimony in which it recommended disapproval of the proposal on the ground that it was not cost-effective as proposed,[1] it did so after considering the new (incremental) costs in relation to the benefits that can potentially be directly linked to those incremental costs. DRA found that the associated benefits were $549 million less than the costs of the upgrade.[2]

Facing this potentially calamitous assessment of its proposal, PG&E had to pull a rabbit out of its hat, as it were. As stated above, PG&E conveniently chose to start characterizing the cost-benefit analysis on a "total project" basis – that is, all the costs of the original project, plus all the costs of the upgrade project – and compared them to the sum total of all the benefits of the project as a whole in the hope that it could argue a better result.[3] It had to do so because in its upgrade filing, PG&E had dipped into the "benefits bucket" of its original application to justify the additional costs of the upgrade. It has argued, that although certain benefits could reasonably be ascribed to the functionalities of the original project,[4] it could now ascribe them to the upgrade because it did not specifically identify them, or quantify them in the original Application. That is astounding. Most troubling of all is that PG&E sees no problem in doing this.[5]

This unexpected and self-serving recasting of benefits in the upgrade application reinforced DRA's concern that PG&E's latest presentation was once again ill-conceived. PG&E should not be permitted to pick and choose its benefits whenever it deems it convenient. For an incremental case to be self-contained and credible, the benefits in each proceeding need to be separately identified, quantified and tied to the particular costs of each respective proceeding.

[1] DRA Testimony, Exhibit 108, Ex. 1, p.1-1

[2] Id.

[3] Ex. 8, Ch. 1-4.

[4] See discussion is Section VI b., below.

[5] TR, Vol. 1, Corey, p.54, line 22, through p. 56, line5.

Given the moving target interveners were faced with in this proceeding, DRA respectfully recommends that the Commission, in its decision in this proceeding, provide clear directives to PG&E on how to present future upgrade cases. Should it file them as "total project" cost-benefit business cases, or should it restrict its future applications to the exact costs of its proposed upgraded systems and technologies, and the benefits that are directly tied to those costs? As for this case, due process concerns demand that PG&E's case be decided upon an incremental, and not a "total project" basis, as that is how the Application was presented. Unfortunately for PG&E however, an incremental analysis shows that this upgrade is not cost-effective, and should therefore be rejected.

c. There should be limitations on how frequently PG&E can file Upgrade Applications

DRA's concern is this: what we have here is a quintessential example of a slippery slope scenario. If PG&E has its way, this could lead to a perpetual revolving door through which it will pass every two to three years to ask for yet another few hundred million ratepayer dollars because there is, for example, a new IT toy on the market. PG&E essentially pounced on some language in Section 14.3 of D.06-07-027 (mimeo, p.57) that stated in part that: "[w]e expect PG&E to monitor market place developments so, *whenever feasible*, it can upgrade its AMI system and *offer* its customers technology upgrades." (Italics added.) Rather than following all the language of the entire section of that decision, PG&E chose to interpret those few words as justification for bringing this $572 million case, and in all likelihood will continue to file similar applications for the indefinite future.

DRA questions PG&E's manifested use of the term "whenever feasible." The Commission needs to clarify what it meant in Section 14.3 of D.06-07-027, because DRA submits that PG&E has hijacked the language to serve its own, and not its ratepayers best interests. The way PG&E has interpreted it, it would seem that the Commission has given PG&E a green light to come in for a multi-million dollar upgrade at the drop of a hat.

II. Choice of Technologies

In Exhibit 108, Ex. 2, Ch. 1, DRA's consultant, Ralph Abbott of Plexus Research, discussed PG&E's troubled past, its present and its future technology choices, and DRA incorporates that entire chapter by reference herein. DRA could cry a river over the past, but understands that PG&E has to move on to improve its troubled system. For purposes of this Brief however, DRA will only highlight those technology choice-related recommendations by Mr. Abbott that may still be contentious.

PG&E's original decision in selecting induction electro-mechanical meters was seriously flawed, as was its original selection of AMI communications technologies and the environments in which they were to be deployed. PG&E's current activity in the Kern territory, and the need to remove and replace a large quantity of meters and AMI equipment is a direct consequence of these bad choices. Ratepayers should not be now saddled with the impacts of PG&E's belated adoption of solid state meters.

As Mr. Abbot testified, he does not believe that two separate and overlapping RF networks, one for gas and a separate network for electric are well advised. This overlap would replicate the mistake in technology application that was made in PG&E's original application. A single RF system by various vendors, including Aclara/Hexagram RF or Silver Spring RF is capable of doing both. Plexus is indifferent to the choice of Aclara/Hexagram RF versus Silver Spring RF, provided that the costs of a belated change and the additional costs of operating and maintaining two RF systems are not borne by ratepayers. A single RF system serving both the gas and electric metering requirements in all but the deep rural areas was the obvious choice from the outset of the PG&E project.

III. Deployment Plan

PG&E's deployment plan has encountered serious challenges that have led it to take the unprecedented step of abandoning the DCSI (or Aclara PLC) communications technology after deploying almost a quarter of a million endpoints. It is now using its Aclara RF gas communications system to backhaul electric data for an additional quarter million endpoints. It was unclear whether this was meant to be an interim solution until

PG&E could begin deploying its now preferred Silver Springs solution. But PG&E now alleges that this will be a permanent solution for those endpoints, and indeed plans to add another 400,000 Aclara RF endpoints before the end of the deployment period.

As indicated above, the end result of these problems is that PG&E has already spent one third of its initial $1.7 billion authorization and yet only has activated 2% of electric meters. It has exhausted $70 million of its $88 million PMO budget when the project is barely off the ground. Furthermore, its information technology budget is already 33% over budget. In general, Mr. Danforth testified that there are strong indications that PG&E's first AMI deployment is in serious trouble. (RT III, 307:25 – 308:5).

The challenges that PG&E encountered with the DCSI equipment appear to be related to unexpected complications that have arisen with DCSI substation equipment installation and with associated head-end software. Mr. Meadows and Mr. Vahlstrom described the nature of these problems under cross-examination. Mr. Meadows reported that it took more time than anticipated for PG&E's engineers to put the DCSI power line carrier equipment in substations. Equipment needed to be of a larger magnitude than was expected (RT I, 83:17-28). Mr. Vahlstrom stated that the problems were related to PG&E purchasing equipment that it did not budget for (RT I, 125:7-13). Mr. Meadows indicated that these led to about a $26 million cost overrun (RT I, 84:3-7).

There is no indication of whether similar workarounds and expenses would have been required for subsequent substations. But it is possible that, had PG&E continued with DCSI, proportional cost overruns would have been incurred in future substation work. PG&E's Semi-Annual Assessment report indicates that 28% of the substation equipment has been installed (Ex. 201, p. 8). Thus PG&E could have been looking at a cost over-run of $92 million (or 1/0.28 times $26 million) had it built out the DCSI system. Added to this might have been unforeseen problems attempting to deploy DCSI in high density urban environments, were it was known to be challenged (Ex. 2, Ch. 1, pp. 3-4 in DRA Ex. 208). PG&E sought to mitigate these unforeseen problems by changing vendors and technologies. Thus, it does not appear that providing customers with increased functionality was the only reason why PG&E filed its upgrade application. While Mr. Vahlstrom states that it was the "primary" reason (RT I, 128:19-24), the record certainly leads one to be circumspect.

In the light of these problems, it might have been prudent for PG&E to merely suspend its deployment while it assessed its options. In fact, one of PG&E's consultants raised this issue to PG&E's steering committee in the summer of 2007, when PG&E was assessing whether to pursue an upgrade. Mr. Lechner testified as follows:

> It was around that time when I actually raised the point to the steering committee that it was important to be looking at the situation as it makes sense to stop the program while this is going on. (RT II, 276:18-22)

Mr. Lechner went on to say that PG&E's project management office ("PMO") itself was evaluating whether to suspend the deployment and decided not to. PG&E and its PMO asked Mr. Lechner to look at their model and its underlying assumption. At the time, they were considering a minimum 18-month suspension for testing and other activities. Mr. Lechner agreed with their results and adopted the same model as his own to analyze a 5-month suspension for his rebuttal testimony (RT II, 276:22 – 277:13). That analysis, however, is seriously flawed, as discussed in Section V.A.5 below.

Whether PG&E will continue to encounter problems as it transitions to yet a third network by Silver Springs is unknown. There are additional risks and unknowns created by the fact that PG&E is deploying a relatively new communications technology from Silver Springs that very few utilities have deployed. Deploying yet another communications system creates additional complications in head-end software from having to interface with yet another system. DRA's consultant Mr. Abbott noted that the simpler approach employed by many utilities is to opt for a single network for gas and electric meter reading in areas where both gas and electric distribution infrastructure exist. This approach also saves money on network costs, and saving money is something PG&E desperately needs to do (Ex. 108, see Ex. 2, Ch. 1). PG&E is here merely repeating an ill-advised approach that it used in its original deployment, when it sought to use an RF network for gas and a PLC network for electricity. Mr. Abbott raised this issue in A.05-06-028 but did not pursue it because PG&E's overall case had sufficient benefits to cover these additional costs (RT III, 327:22 – 328:7). That is not the case, however, in the AMI upgrade proceeding.

The irony is that Mr. Abbott's preferred approach was actually recommended to PG&E's steering committee in December 2007 by PG&E's witness Mr. Vahlstrom. He stated that the solution would work in the gas footprint areas, which overlap with some 85% of the electric footprint areas. His presentation makes reference to "significant opportunities to achieve project cost savings" using this approach (Ex. 107). In spite of this, PG&E oddly has embarked on the more costly approach of adding a third Silver Springs network. The benefits associated with this additional cost are uncertain. There are advantages of using a mesh-type RF network such as Silver Spring's in the deep rural areas where there is no gas footprint. But employing the Aclara network to backhaul both gas and electric meter reads in areas where both services exist does not preclude using a different network in the deep rural areas.

At the end of the day, DRA is not sure what PG&E will cobble together. Its deployment history has been one of major problems and significant changes in direction. DRA can only hope that it doesn't see another upgrade application two years from now disguised as a "Smart Grid" proposal.

IV. Overall Cost-Benefit Analysis

DRA attempted to assemble a business case that would be cost effective to provide constructive input to the Commission's deliberation process. Regrettably, it was unable to do so. Subsequent errata resulted in costs and benefits further diverging relative to DRA's initial opening testimony.

DRA provides its final costs and benefits in Tables 1 and 2 below. As shown, costs exceed benefits by about $76 million (PVRR). Thus DRA recommends that PG&E's AMI Upgrade project not be approved. The $309.3 million (PVRR) figure on line 1 of in Table 1 for meter and equipment costs reflects a $91.7 million (PVRR) reduction from the $401.0 figure given in DRA's most recent errata (See Table 1-2, line 1, of Ex. 2, Ch. 1 of DRA's Ex. 208). This reduction is the $61.1 million (nominal direct dollars) adjustment to Mr. Levesque's figures that Mr. Danforth provided in direct testimony (RT III, 288:3-9). The $61.1 million reduction was converted to $91.7 million in PVRR terms using the process described in the first chapter of DRA's opening testimony (Ex. 108, p. 1-4). As described in Section V.a.1 below, DRA believes the $61.1 million reduction to be an underestimate, but most likely by not enough to render PG&E's AMI Upgrade cost effective.

The contingency allowance shown in Table 1 on line 8 has been proportionally reduced. In addition, the contingency allowances on all categories have been modified to reflect TURN's errata changing the allowance from 7.4% to 7.997% (Ex. 208, p. 3)

Table 2 shows the benefits. The electricity conservation benefits have been increased by $35 million to reflect higher avoided cost numbers that PG&E reported in its rebuttal testimony (Ex. 8, Ch. 4, lines 16-18).

Table 1

AMI Upgrade Benefits
PG&E vs. DRA Estimates
($ in thousands)

		PG&E	DRA
Line No.	**Category (a)**	**PVRR (b)**	**PVRR (c)**
1	Labor Savings	$114,702	$114,702
2	Bad Debt Savings	26,756	26,756
3	Improved Cash Flow Savings	11,174	11,174
4	Tax Benefit of Meter Retirement	11,799	11,799
5	**O&M Benefits Subtotal**	**164,430**	**164,430**
6	Energy Conservation	479,071	$208,642
7	Demand Response Benefit – PTR	290,222	0
8	Demand Response Benefit – T24	129,401	0
9	**Energy Benefits Subtotal**	**898,694**	**$208,642**
10	**Total Project Benefit**	**$1,063,124**	**$373,072**

Table 2

AMI Upgrade Costs
PG&E vs. DRA Estimates
($ in thousands)

Line No.	Category (a)	PG&E PVRR (b)	DRA PVRR (c)
1	Meter Equipment	$516,034	$309,300
2	Information Tech.	52,589	48,580
3	T24 Program	37,906	0
4	PTR Program	27,592	0
5	Project Management	17,954	0
6	Electro-Mechanical Meter Upgrade	40,431	6,873
7	Training	1,592	1,592
8	Risk Based Allowance	55,568	29,297
9	**Meter Deployment Costs Subtotal**	**749,667**	**395,642**
10	Operations & Maintenance	95,726	40,953
12	Risk Based Allowance	521	3,275
13	Subtotal – Operations & Maintenance	96,248	44,228
14	**O&M Cost Subtotal**	**845,914**	**439,870**
16	Technology Assessment	35,285	8,379
17	Risk Based Allowance	6,249	670
18	**Other Costs Subtotal**	**41,534**	**9,049**
19	**Total Project Costs**	**$887,448**	**$448,919**

a. Use of incremental costs/benefits vs. total costs/benefits

As the AMI upgrade proceeding has evolved, the issue of whether to evaluate PG&E's request *including* or *excluding* costs and benefits evaluated in A.05-06-028 has received increasing interest. What brought this issue to the forefront is PG&E's allegation in rebuttal testimony that, when the total cost of PG&E's request is evaluated, it is comparable to those of SCE and SDG&E on a per meter basis (Ex. 8, page 3-18). PG&E made this assertion fairly late in the proceeding even though it initially presented its analysis on an incremental basis that excludes the costs and benefits adopted in A.05-06-028.

First of all, there is insufficient information in the record to adequately compare PG&E's per meter costs with those of SCE and SDG&E. As Mr. Danforth testified, numbers expressed on a total basis are confounded by fairly significant cost differences between AMI electric and gas endpoints. A new electric endpoint, with its integrated service switch, HAN interface, and remote programmability, is considerably more expensive than the communications module attached to existing gas meters. Furthermore, there are differences between utilities in that SDG&E proportionally has more electric meters relative to gas meters than does PG&E (RT III, 361:2 – 362:26). If PG&E thought this was an important issue, it should not have waited until its rebuttal testimony to raise it.

But even beyond this, there is a significant question of whether applications for major capital expenditures should be evaluated on a total basis that includes the costs and benefits of the first case. As Mr. Danforth testified, economists generally favor performing cost-benefit analyses on an incremental basis. The reason for this is because, even if a project can be justified on a total basis, if it in itself has a negative net present value, going forth with the incremental project dilutes the costs and benefits of the initial project. Economists aim to maximize the net present value, and this requires that each increment stand or fall in terms of whether it *adds* net present value to the overall project (RT III, 339:12-25). Indeed, why spend money only to reduce customer welfare?

PG&E appears to believe in this standard economic approach sufficiently as it did initially come to the Commission with an incremental case, where the previously adopted costs and benefits were, according to PG&E, excluded. Where DRA and PG&E depart, however, is that DRA believes that one cannot include in the upgrade benefits that *could have been achieved* by the AMI system examined in A.05-06-028. If they could have been achieved by the original system, they are not truly incremental benefits made possible by the upgrade, and they do not add net present value to PG&E's AMI system. Granted, DRA's standard is more stringent, but it prevents abuse of the regulatory system whereby any number of benefits can be brought in to justify a project. Given the likelihood of more funding requests arising for the implementation of a "Smart Grid", the Commission needs a fairly stringent standard.

Even though PG&E's presentation used a rather liberal interpretation of concept of "incremental", it now wants to expand that further and look at both AMI cases on a total basis. Clearly this is extremely difficult to do in the post-rebuttal stages of the proceeding. DRA analyzed what was presented to it, and that was an incremental analysis. To now be asked to look at the case on a total cost and benefit basis is a violation of DRA's due process rights because an entirely different kind of analysis would have been required.

If DRA were to evaluate PG&E's case on a total basis, it would need to consider inefficiencies that have been produced by PG&E changing technologies and vendors after deploying more than half a million endpoints (RT III, 340:1-7). The most obvious inefficiency is the need to discard either entire endpoints or internal parts of endpoints and the additional labor costs involved in doing so. The costs associated with these are approximately $47.3 million (nominal direct dollars).[6] There are also unexpected complications that have arisen with DCSI substation equipment installation and with

[6] PG&E's actual request for the two was $73.8 million, or $43.6 million for the Kern County electromechanical meter retrofit and $30.2 million for the retrofit of the 288,000 meters using the Aclara RF communications modules that are missing the HAN interface. But the $47.3million figure takes out the cost of the integrated service switch and HAN, as well as the labor costs for the Kern County retrofit, which DRA would allow for reasons explained in Mr. Levesque's testimony (cf. Ex. 108).

associated head-end software that evidently had cost implications and the potential of stranding of costs. The fact that only 2% of PG&E's meters are activated after spending almost one third of the money suggests the possibility of further stranded costs. These costs would not have been stranded had PG&E executed its AMI deployment in one segment rather than two.

While investigating the cost implications of changing vendors and technologies begins to sound like a reasonableness review, these additional costs cannot be ignored if PG&E now wants to look at the AMI deployment on a total basis. It is true that the ratemaking formulation adopted in A.05-06-028 did not allow for reasonableness review unless project costs were exceeded by more than $100 million. But the assumption behind that approach was that PG&E would deploy the technology it started out with rather than coming back requesting a significant upgrade before that money was spent. Mr. Danforth indicated that, had an analysis on a total basis been called for, all these problems would have had to have been investigated. But it is too late to do so now. If PG&E had preferred that its case be evaluated on a total basis including the original case, then it should have presented its cost-benefit analysis on a total rather than incremental basis. If the Commission believes that this would be a preferable way to view PG&E's case, then it should reject the current application and ask PG&E to file a new case in which the analysis is presented on a total basis.

While it might be tempting to simple-mindedly add the benefits and costs of the two cases together, doing so would be inadequate. It would not consider the above inefficiencies and how the money in the original authorization has been wasted. It is true that PG&E, by changing technologies and vendors, seems to have contained the costs well within the authorized spending cap in A.05-06-028. Yet more money has been spent in the long run than would have been had PG&E started with the upgraded technology to begin with.

V. Specific Costs

a. Deployment Costs

i. Meter and equipment costs

Perhaps one of the most difficult cost categories, but probably the most important, is the cost of the meters and associated communications equipment. Since DRA is supportive of the HAN and service switch, it recommends funding costs associated with this increased functionality. A major associated cost is that of advanced solid-state meters required to support that functionality.

It is important, however, to subtract from that cost the funding that PG&E already received in A.05-06-028 for new or retrofitted meters. DRA also excluded all labor and network costs that were previously funded in A.05-06-028 except for labor costs associated with the Kern County retrofit. DRA included the labor costs for the Kern County retrofit because revisiting those meters would have been necessary anyway to provide the enhanced functionality. Those retrofit costs are discussed below in Section V.a.v. In regard to network costs, DRA's consultants stated that further cost savings are available by using a single network for gas and electric meters in each geographical area. But DRA was unable to quantify these savings (Ex. 108, see Ex. 3, Ch. 2 and 6).

Though the analysis DRA performed is simple in principle, it was difficult to determine the following: (1) The appropriate cost for advanced solid-state meters, and (2) The cost of previously funded meters that needed to be subtracted out. DRA initially attempted to rely on PG&E's figures for #1 to limit the debate, but difficulties with this approach ultimately led DRA to derive its own cost estimates for advanced solid-state meters. DRA's consultant ultimately relied on confidential bids at his disposal from seven vendors (See DRA workpapers for Ex. 3, Ch. 2 in Ex. 108). His company had signed non-disclosure agreements to receive this information, and thus he could not divulge the sources of this information or the underlying terms and conditions.

There are two important things to realize about Mr. Levesque's meter cost information. First, though Mr. Levesque specifically used the lowest three bids amongst his sample set of seven, the average of the whole sample of seven produces a number in the same general range as PG&E's proposed cost. DRA directed him to use the lowest three because, knowing it couldn't produce enough benefits to justify PG&E's meters, DRA asked him for a "barebones" estimate. Second, the meters on which Mr. Levesque received quotes may have a lower level of functionality than do those that PG&E assumed in its presentation. But Mr. Levesque believes the meters he assumed provide sufficient functionality to support the HAN, and they all include integrated service switches. Furthermore, the three on which he based his cost estimates are remotely programmable (RT IV, 517:2-9). It is very unclear from the record the exact nature of the increased functionality that PG&E's meters provide, nor why this functionality is necessary.

One would think the easy part of this analysis would be problem #2, which is that of determining what meter costs already approved in A.05-06-028 should be subtracted from the cost of the advanced solid-state meters. But even this proved difficult because PG&E, in its May supplement, assumed funding for a basic Tier 0 solid-state meter for all customers. Whereas A.05-06-028 had only provided funding, for the residential sector, for replacing roughly one-third of the existing electromechanical meters, and merely refurbishing the rest of those meters at a fraction of the cost of a new one. PG&E apparently decided to subtract from its advanced meter costs more costs than A.05-06-028 actually funded because there were compensating cost savings in other areas that allowed this (Ex. 105 and 106). Though PG&E wasn't clear what those other areas were, cost savings associated with using a Silver Springs RF-type network rather than the DCSI PLC-type network may have been part of it. PG&E also moved to a model where every customer would receive a new basic Tier 0 solid-state meter (which costs about the same as a new electromechanical meter) because the Silver Springs modules are incompatible with electromechanical meters (RT I, 92:15-20).

DRA did not adequately understand this evolution in PG&E's thinking. Indeed, it is only mentioned in a rather cryptic one-sentence footnote in PG&E's supplemental testimony (Ex. 7, App. B, Revised Table 2-2, footnote a). Thus Mr. Levesque merely followed what had been authorized in A.05-06-028, which provided funding to replace only one-third of the existing electromechanical meters rather than providing solid-state meters to everyone. Mr. Danforth believed it would be appropriate to modify Mr. Levesque's figures to put them on a comparable basis with PG&E's revised numbers. Thus he presented errata suggesting that PG&E's $61.1 million reduction be used as a proxy for the effects of putting Mr. Levesque's numbers on a comparable basis (RT III, 288:1-9).

DRA stresses that the $61.1 million is only a proxy of this reduction. In fact, a larger reduction can be achieved by directly substituting a blended cost for a Tier 0 basic solid-state meter, which can be found in PG&E's workpapers, for the cost of new and retrofit electromechanical meters in Mr. Levesque's Table 2-1. Doing this would more than compensate for other errors that PG&E alleges that Mr. Levesque made (RT IV, 543:24-26 and 544.21-25), or from including the additional PMO and Wellington overhead charges from suspending the AMI deployment until the end of this year. DRA will refrain from further changing its estimates because there are compensating changes that could be made in both directions. At this point, DRA believes its cost estimate is sound, and the Commission should give little weight to PG&E's allegations of errors in those numbers.

ii. Information Technology Costs

DRA's opening testimony (Ex. 108) describes how it calculated information technology ("IT") costs in Chapter 4 of Exhibit 3 of that testimony. As explained, DRA only excluded costs associated with the Peak Time Rebate ("PTR") program. DRA only excluded these $4 million (PVRR) in costs because it did not include the associated benefits (See Section VI.B below). DRA did not want to burden its business case with costs that have no associated benefits. If the PTR program is funded in another proceeding, the associated IT cost could be considered there. DRA noted for the record that an unnecessary duplication of IT costs has occurred because of PG&E's choice to implement a communication system as part of its SmartAC program that is duplicative of the HAN communication system. But because DRA is supportive of the HAN technology, it did not exclude the IT costs associated with HAN communication.

iii. Title 24 and PTR program costs

DRA excluded costs in both the Title 24 and PTR categories because it did not have associated benefits in its business case. As discussed above for HAN-related IT costs, it did not want to burden its business case with costs that have no associated benefits. These could be funded in other proceedings. However, funding of any Title 24 program costs will need to wait until the California Energy Commission ("CEC") issues its next iteration of Title 24 standards for new buildings in 2011. PG&E had included in its business case costs and benefits associated with integrating and using programmable communicating thermostats ("PCT") that were in the draft Title 24 standards. But the CEC removed the PCT from its standards in January 2008, one month after PG&E filed its AMI upgrade application. PG&E chose not to reflect this change in its May supplemental testimony.

DRA believes the situation is too uncertain at this time to include Title 24 costs and benefits.

iv. Project Management

DRA has not included additional project management costs in its business case. PG&E has already received recovery for $87.5 million (PVRR) in A.05-06-028 and now seeks to recover an additional $18.0 million (PVRR). DRA excluded these costs completely from its business case because it believes that what PG&E received in the original case was sufficient.

DRA further elaborates on its reasons for excluding this cost in its opening testimony (Ex. 108) at page 2 of Chapter 6 of Exhibit 3 in that report. PG&E asserts that there is additional complexity associated with managing multiple technologies. Yet, in its Original Application, PG&E argued for the need for multiple technologies, one for gas and one for electric, and included the cost to manage the deployment of and operation of these multiple technologies. The Upgrade proposes to eliminate the PLC technology, deploying only the Aclara RF technology. PG&E then anticipates introducing a second technology, Silver Springs, creating the need to manage a second technology. But, in essence, PG&E still is managing only two technologies as proposed in its Original Application.

v. Retrofit Costs

There are really two retrofits that PG&E is contemplating. The first one is the so-called "Kern County Retrofit" associated with removing and replacing some 230,000 DCSI PLC communications modules. The second one is the so-called "Ubiquitous HAN" which involves retrofitting some 288,000 Aclara RF endpoints with the HAN interface. PG&E shows the first under a separate category in its testimony called "Retrofit Costs". The costs associated with the second are built into PG&E's meter and equipment cost category. DRA's computations for meter and equipment costs discussed in Section V.A.1 above include the endpoint costs for both these retrofits.

DRA is supportive of the enhance functionality associated with the HAN and the integrated service switch. It also supports the advanced Tier 1 solid-state meter required for both these functions. Thus DRA includes these in these costs in its business case even for the two retrofits. It also includes the labor costs for the Kern County retrofit because a second visit to these meters would have been required anyway to install this new functionality. Unlike PG&E, DRA did not include the cost of new communications modules and network costs for the Kern County retrofit because it believes that the choice of the DCSI system was questionable to begin with.

DRA excludes all costs associated with the Ubiquitous HAN retrofit except those directly associated with enhanced functionality. The latter are discussed on Section V.a.i above. DRA believes that PG&E could have merely suspended the deployment of these costs and avoided the additional costs that PG&E includes. Nevertheless, PG&E chose to move ahead with the 288,000 units six months before a HAN comparable with the Aclara communications board was available.

PG&E chose to not suspend the project because of a cost-benefit analysis performed jointly by PG&E's PMO that was later adopted by its consultant Stephen Lechner. This cost-benefit analysis is contained in Chapter 10 of PG&E's rebuttal testimony (Ex. 8). It shows that the costs that could be saved from deferring the AMI deployment by five months are $11.5 million (PVRR)[7], which is less than the foregone benefits of $39.5 million (PVRR) from delaying the project. The foregone benefits come from the assumption that all 5 million meters that will be installed subsequent to the 288,000 meters will be delayed by a comparable amount of time. Thus delaying the 288,000 meters delays the entire project.

Mr. Lechner's analysis is somewhat mooted by the fact that the deployment has already been delayed by at least five months.[8] In addition, his cost-benefit analysis is highly distorted by three problems: (1) It ignores the present value cost savings of delaying the deployment of the subsequent 5 million meters, (2) It artificially truncates the stream of foregone benefits for all scenarios to 2011, and (3) It includes different numbers of months of foregone benefits for the four scenarios evaluated. These problems are discussed below.

Regarding the first problem, Mr. Lechner ignored the cost savings from delaying the deployment of some 5 million meters apparently because he didn't find them to be important enough to include (RT II, 271:6-22). The particular studies that led him to this conclusion are not in the record. But, because of this decision, the only *endpoint* costs Mr. Lechner includes in his analysis are those associated with the 288,000 meters, which he then compares with the foregone benefits associated with over 5 million meters. The result is predictable – the benefits dominate the analysis. Mr. Lechner interprets this result as a clear "green light" to proceed without the HAN interfaces.

In assessing whether Mr. Lechner's decision to ignore all the costs associated with the subsequent $5 million meters is sound, we must ask what those costs are. Table 1 on page 28 of D.06-07-027 shows that 60% of the costs of the original AMI system was in

[7] This represents the $30 million in retrofit costs, net of the cost of doing the work later at lower cost, less the increased costs from suspending the installation installers and the PMO as well as from labor escalation in the installation costs.

[8] The original deployment plan called for the AMI deployment to be completed by August 2011 (RT II, 262:25 – 263:3). Mr. Lechner's analysis of the benefits concludes at the end of 2011 because he assumes this retrofit would not occur until the rest of the meters had been deployed.

the endpoints and network.[9] One would think that a large portion of these costs are deferred when the project is deferred. Thus, had Mr. Lechner offset the foregone benefits from deferring the installation of 5 million meters with the associated cost savings, the net result would have been up to 40% smaller than what he calculated. Therefore, his foregone benefits appear to be inflated by some 2.5 (1 divided by 0.4) times.

The second problem was that Mr. Lechner truncated the period of analysis such that it would end in 2011. This is in spite of the fact that the benefits persists for the projected 20-year life of the endpoints for all four scenarios he considered. Had Mr. Lechner not truncated the benefits streams, the benefits in nominal terms for each of the four scenarios would have been identical. The only difference would have been in the timing of the benefits. Given the adopted discount rate in D.06-07-027 of 7.6% (see p. 47), the difference in benefits between the non-suspension scenario and the five-month suspension scenario should only be 3.2% (or five twelfths of 7.6%). Mr. Lechner, in contrast, shows close to a 25.6% difference in benefits between these scenarios.[10] This means that his foregone benefits differential for these two scenarios is inflated by some 8 times.

The reason why the benefits differentials are so inflated is because of the third problem. Artificially truncating the benefits of all scenarios to the end of 2011 resulted in a five fewer months being used to calculate the benefits for the five-month scenario relative to the non-suspension scenario.[11] Had he allowed the benefits streams to continue for the lifetime of the equipment, the benefit streams for all the scenarios would

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[9] DRA included the cost categories on lines 3, 4, 8, 9, 10, and 11 in the second column (PVRR) of Table 1 in calculating this percentage. These categories include gas meters that had to be included because the total on line 18 also includes gas meters. But the electric meters are a higher proportion of the project cost.

[10] In Ex. 8, Appendix 10-1 the benefits shown for the non-suspension and five-month suspension scenarios are $193.8 million (PVRR) and $154.3 million (PVRR) respectively.

[11] Mr. Lechner's excuse at page 273 (line 24) to page274 (line 6) of the recorded transcript – that he included the same number of months for all scenarios but the first five of the five-month suspension scenario happen to be zero – is missing the point.

have included the same number of months. The only difference would be the point in time when they would have occurred.

The information in the record does not allow DRA to provide a precise counterexample to Mr. Lechner's analysis that corrects for these deficiencies. But we know that the benefits differential is inflated by some 2.5 times because of the first problem and by some 8 times by the second and third problems. Thus his benefits differential of $39.5 million (PVRR) could be inflated by some 20 times (or 8 times 2.5). Reducing $39.5 million by that amount yields a foregone benefit level of $2.0 million, clearly way below his estimated cost reduction from a five-month suspension of $11.5 million.

The benefits, if modeled correctly, would not dominate the analysis as they do Mr. Lechner's work. Rather, the main tradeoff would be between the avoided cost of not having to retrofit the 288,000 meters ($28.7 million[12]) and the additional overhead costs created by a suspension (approximately $2.0 million per month[13]). Based on Mr. Lechner's information, PG&E could have suspended the deployment of these meters for as much as a year before the additional overhead costs would have exceeded the avoided costs on a nominal basis. On a present value basis, the period of time would have been slightly less.

b. Operations and Maintenance Costs

DRA's benefit calculations reflected use of a lower HAN adoption rate than PG&E's (See Section VI.b below). Accordingly, DRA recommends reducing PG&E's call center costs by 70% to reflect the fewer calls that will be received as a result of DRA's lower HAN adoption rate (Ex. 3, Ch. 3, p. 3 in DRA's Ex. 108)

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12 This is equal to $32.5 million minus $3.8 million, both taken from Appendix 10-1 in Ex. 8.

13 This is equal to the sum of $3.8 million, $1.3 million, and $0.7 million, all divided by 3. All these figures were taken from Appendix 10-1, Ex. 8.

c. Technology Assessment Costs

Perhaps the most discretionary cost associated with PG&E's request is its request to spend $37.9 million (nominal direct dollars) on technology assessment. Given that this request came in response to a Commission directive to monitor the market (D.06-07-027. p. 57), DRA has proposed that this program be partially funded. DRA suggested the more modest amount of $9 million (direct nominal dollars). DRA's figure would allow for the monitoring of emerging technologies. It excludes the cost of a technology laboratory, a demo facility for HAN devices, HAN standards work, development of a Zigbee device that can be plugged into a computer, and an ongoing pilot test of the Silver Springs Network.

DRA does not believe there are sufficient benefits in PG&E's business analysis to cover these costs. If the Commission disagrees, DRA would suggest moving up to a figure of $15.4 million, which is what PG&E included in its initial application and testimony in December 2007. That figure would only cover the monitoring of new technologies and the Silver Spring pilot, which is currently being carried out by PG&E anyway. The fact that PG&E has added $22.5 million to its request in the May supplemental testimony should be disregarded. If $15.4 million was sufficient for PG&E in December 2007, why is it not sufficient in May 2008? PG&E's supplemental testimony gives no justification for this increase.

Indeed, much of the added work that PG&E proposes is more properly done by organizations such as the Electric Power Research Institute, by national research laboratories, or by consortia jointly financed by several utilities. No other California utility has received an authorization to perform AMI-related research and development work at the same level as what PG&E has requested. While SCE may have received more pre-deployment money than PG&E, adding $37 million will clearly put PG&E higher than SCE. SCE received a total of $67 million in pre-deployment funding ($12 million in A.05-03-026 and $45 million in A.05-12-026), while PG&E received $49 million. When $37 million is added to $49 million, the result is $86 million.

TURN also raises the issue of whether, when the Commission directed PG&E to monitor the market, it contemplated a level of funding similar to what was authorized in the pre-deployment funding. It observes that the Commission probably did not envision an activity that couldn't have been accommodated in the $1.739 billion PG&E was already authorized in the original AMI deployment (Ex. 208, p. 24). Otherwise, the Commission would have provided explicit funding for this item.

d. Risk Based Allowance

DRA has deferred to TURN on this issue. DRA's figures in Table 2 have been modified to reflect TURN's errata changing the allowance from 7.4% to 7.997% (Ex. 208, p. 3). If TURN makes further changes to the contingency allowance in its opening brief, DRA will reflect this in its reply brief.

VI. Specific Benefits

Herein lies the problem with PG&E's upgrade business case: no matter whether the Commission adopts PG&E's or DRA's estimate of the reasonable costs to fund the intended upgrade's technical requirements, they are higher than the potential benefits. Table 1-1 in DRA's testimony (Ex. 108, Ex. 1, p.1-1) shows DRA's adjustments to PG&E's benefits calculations. As will be discussed below, these benefit reductions were largely due to the fact that a significant amount of the benefits PG&E attributes to the upgrade were either accounted for in its original application, or are double counted because some of them are being relied upon by PG&E in other proceedings before the Commission.

a. Operational Benefits

DRA finds PG&E's estimated operational benefits reasonable.

b. Energy Conservation and Demand Response

PG&E claims $479 million in energy conservation benefits in terms of present value revenue requirement (PVRR), comprised of $312 million in electric energy conservation, and $167 million in gas conservation. DRA calculates that only $174 million in conservation benefits should be attributed to the Upgrade. DRA's review of these benefits can be found in Exhibit 108, Ex. 3, Ch. 5A, incorporated herein by this reference.

DRA also adjusted PG&E's demand response benefits calculations for the Upgrade on the basis that i) the peak time rebate (PTR) benefits can be attributed to the approved AMI system rather than the upgrade –a reduction of $290 million in PVRR; and ii) the Title 24 Programmable Communicating Thermostat (PCT) – related benefits do not belong in this proceeding as PG&E has already counted that demand response benefit in its approved SmartAC program – a reduction of $129 million in PVRR.

In Section 1 b., above, DRA discussed the problem that PG&E's "incremental" upgrade application posed in terms of determining which specific benefits can be appropriately attributed to the upgrade, as opposed to the original project. As stated above, DRA believes that one cannot include in the upgrade benefits that could have been achieved by the AMI system examined in A.05-06-028. If they could have been achieved by the original system, they are not truly incremental benefits made possible by the upgrade.

i. Energy Conservation

1. Electric

DRA's analysis of the upgrade's potential electric energy conservation benefits hinges on three issues: i) a comparison of the daily information feedback that customers can achieve through PG&E's approved AMI system, as opposed to the real-time feedback that the upgrade potentially provides - a $30 million adjustment; ii) a different annual adoption rate of information display technology – an $84 million adjustment; and iii) a double counting of energy efficiency benefits issue between this application and the energy efficiency program proceeding – a $24 million adjustment.

As for the current Application, PG&E claims the Upgrade will deliver electric energy conservation of 10,194 gigawatt-hours (GWh) cumulatively from 2012 through 2030, approximately $312 million of benefits in terms of PVRR. This conservation benefit is based on the HAN capability of the Upgrade system to provide a communication conduit into the home that will provide a "*real-time*," or "*direct*" information feedback. PG&E assumes residential customers will purchase in-home information feedback devices (IHD's) that will be able to communicate with the meters. Electric energy consumption information can then be transmitted directly from the meters to the in-home information displays. Based on this direct transmittal of consumption information, PG&E claims residential customers will curb electricity consumption worth up to $312 million cumulatively from year 2012 through 2030. Inherent in PG&E's argument is the assumption that this conservation benefit is solely due to the Upgrade.

In calculating this conservation benefit, PG&E assumes a

(1) 30 percent adoption rate of HAN-enabled display devices by 2024, and

(2) 6.5 percent of energy savings among households with HAN-enabled information displays.

i) "Day-Late" Feedback belongs in the Original case, and "Real-Time" Feedback belongs in the Upgrade case.

In DRA's testimony in Exhibit 108, Ex.3, Ch.5A, at pages 5-6, Ms. Lee discusses the distinction between "*direct*," or "*real-time*," and "*indirect*," or "*day-late*" feedback and their relation to potential energy conservation benefits. PG&E asserts that the HAN provides "*real-time*" feedback that the original application could not. DRA accepts that direct information feedback has some potential to deliver conservation benefits, and has recognized those benefits in the open standard HAN interface of the SDG&E and SCE AMI systems. Upon analysis of the PG&E benefit calculation, however, DRA questioned the amount of identified conservation benefits that can be attributed to the added HAN functionality.

Only *real- time* information-driven conservation is potentially attributable to the Upgrade. The distinction between the effects of *real time* versus *day-late* information is important for the purpose of examining the Upgrade application. *Day-late* information feedback conveyed via the personal computer is valuable and can be achieved with the already approved AMI system.

In order to test whether PG&E is indeed offering customers incremental energy conservation benefits or not with the upgrade, it would help to remind the Commission what PG&E's position was in its original Application. DRA has gone back and read PG&E's Opening Brief in A.05-06-028 which is enlightening in this regard.

In support of its AMI Deployment Application 05-06-028, PG&E argued that there were indeed additional benefits beyond operational savings and demand response benefits that warranted the approval of its proposed AMI system. It argued that these additional benefits included timely customer access to personal usage information such that customers could manage their own energy consumption. Specifically PG&E stated

> "PG&E's analysis shows that 89% of the costs are offset by operational savings. The remaining costs of the project are offset by demand response benefits… However, AMI will produce many additional benefits that will not reduce utility revenue requirements, or that are hard to quantify, or even unquantifiable (referred to here as 'societal' benefits.) … **[T]he record shows numerous and substantial societal benefits can be expected from AMI and are a major justification for proceeding with the [AMI] Project. These benefits include: … the value to customers of improved usage information to manage energy bills**"[14] (Emphasis added)

PG&E has thus already identified these potential energy savings benefits in support of its Original AMI Project, but wants to claim them again in this upgrade application. PG&E elaborated that the timely access to personal usage information would result in *customer participation in energy conservation*, and it also quantified those benefits in its transmission and distribution (T&D) benefits calculation. Specifically, PG&E argued that

> "AMI will result in a huge increase of energy usage data available to customers, the utility, energy service providers (ESPs), and potentially other third parties. Compared to today's monthly electric and gas usage meter reads for most customers, **the proposed system will collect hourly usage data for each electric customer and daily usage data for each gas customer. PG&E has quantified in its business case several ways in which this enhanced data will produce savings in electric and gas T&D operations. In addition, however, this wealth of data will have significant benefits to customers, and other stakeholders in managing and meeting their energy needs…** PG&E

[14] A.05-06-028, Opening Brief of PG&E dated April 3, 2006, p.54.

> proposes… to allow customers to access and use the data available from the AMI system… P**G&E has proposed that all customers, including residential customers, be able to access their detailed usage patterns, through the previous day, on the Web. This access will enable customers to better manage their energy bills and participate in demand response and energy conservation programs.**"[15]

Although the benefits of providing customers with timely access to their personal usage information were not explicitly labeled as "energy savings benefits," PG&E's Original AMI Project relied on them as "customer service improvement benefits."[16] Furthermore, PG&E argued that "enhanced energy information" that would result in energy conservation should be given "qualitative consideration,"[17] even if the benefits were not explicitly quantified. In fact, PG&E listed numerous additional "societal benefits" beyond customer access to personal hourly usage data and urged the Commission to "recognize [such benefits] –quantified or un-quantified— in evaluating PG&E's AMI Project."[18]

In DRA's testimony in this case, it stated that "PG&E claimed in the Original AMI Application that its electric AMI system would be able to collect 'hourly interval data in compliance with CPUC requirements.'[19] Based on PG&E's claim that 'customers will also have access to their personal usage data in order to assess their own energy usage patterns,'[20] the Commission directed that 'PG&E should provide free web access to day-after data for individual customers.'"[21]

In light of the above, PG&E cannot with any credibility now claim that personal hourly usage data is an incremental benefit. Conservation benefits of day-late

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[15] Ibid., p.60-62.

[16] A.05-06-028, PG&E Reply Brief dated April 14, 2006, p.41-42.

[17] A.05-06-028, April 14, 2006, PG&E Reply Brief, p.41-47.

[18] A.05-06-028, April 14, 2006, PG&E Reply Brief, p.48.

[19] Original AMI A.05-06-028, Exhibit 2-1, p. 1-5, line 18.

[20] Original AMI A.05-06-028, Exhibit 2-1, p. 1-4, line 9-10.

[21] Original AMI Decision 06-07-027, Conclusion of Law No. 16, p. 67.

information, therefore, should not be counted as an incremental benefit attributable to the Upgrade, as the capability to deliver hourly information a day late will not be an incremental function of the Upgrade equipment.

With the above in mind, DRA then went on in its testimony to further refine its analysis of the specific upgradable energy benefits. It analyzed PG&E assumption that, given in-home HAN technology adoption, households will conserve on average 6.5 percent annually.[22] PG&E's conservation benefit is calculated based on its total forecasted annual residential load, from year 2012 through 2030. Inherently assumed in this calculation, is that all household end-uses could be curbed 6.5 percent on average, if customers decide to purchase an in-home information display device.

Based on discovery and empirical literature, DRA proposed that PG&E's electric conservation benefit be modified according to end use. Using the California Energy Commission 2006 Update to the Residential Appliance Saturation Survey results for the PG&E service territory, DRA calculated that approximately 9.5 percent of the residential load is attributable to space heating and cooling, with the other 90.5 percent of residential energy sales attributable to base energy usage. DRA used this breakdown to modify PG&E's calculations. Specifically, it applied the 90.5 percent scalar adjustment to PG&E's annual residential sales forecast. This modification discounts the portion of residential sales forecast due to space heating and cooling load, and leaves only the base energy load in the benefit calculations. As *real-time* information feedback affects primarily base energy use, the estimated 6.5 percent conservation rate should apply only to base energy use, in other words, end uses other than space heating and cooling. This modification reduces the electric energy conservation from $312 to $282 million in PVRR.

ii) DRA and PG&E Disagree on the Adoption Rate of Real-Time Information Display Technology

[22] In PG&E's workpapers supporting Exhibit PG&E-7, Supplemental Testimony Overview and Policy, dated May 14 2008, WP 1-75, the 6.5 percent conservation rate is uniformly applied to PG&E's total annual residential sales.

PG&E's claimed conservation benefits of the HAN interface hinge on customers voluntarily investing in display devices to manage home energy use. PG&E assumes that the technology adoption rate of in-home information display devices will resemble that of historic cellular phone adoption rates. PG&E assumes that the adoption rate will increase from 2 percent at year 2012 and plateau at 30 percent at year 2024, following the *s*-shaped cumulative probability distribution curve.

At pages 6-7 in Exhibit 108, Ex. 3, Ch. 5A, DRA described why it finds the comparison of information display technology to cellular technology to be unpersuasive. To correct PG&E's analogy to cellular phone technology, DRA proposed the projected adoption rate of HAN-enabled information display technology be modified to resemble that of the more analogous historic adoption rate of residential energy efficient technology, specifically that of compact fluorescent lamps (CFLs). DRA believes that the consumer base for in-home energy management technology, such as information displays, will more likely resemble the market segment for CFLs.

After some analysis, DRA proposed the HAN-enabled information display technology adoption rate be modified to better resemble the adoption trajectory of CFLs. It modified PG&E's annual HAN technology adoption rate by a ratio of 21 to 30, which is equivalent to a scalar adjustment of 0.7. This adjustment results in the projected annual adoption rate increases from 0.1 percent in year 2012 to 21 percent in 2024, which DRA regards as an already optimistic adoption rate. This further reduces PG&E's electric conservation benefits from $282 million to $198 million in terms of PVRR.

2. Gas

PG&E claims its proposed electric AMI meter upgrade will enable gas conservation. Specifically, PG&E projects the electric metering system upgrade to provide $167 million of gas conservation benefits, in terms of PVRR.[23] This benefit reflects PG&E's gas conservation benefit claim of 52,612 billion British thermal units (BTU) cumulatively from 2012 to 2030. DRA questions the effect of the electric

[23] A.07-12-009, PG&E SmartMeter Upgrade Exhibit 3-5, Table 5-4, line 4.

metering system upgrade on gas conservation. In fact, PG&E stated in its SmartMeter Upgrade deployment plan that

> "The proposed SmartMeter Program Upgrade does not affect PG&E's gas meter infrastructure."[24]

As PG&E states, the electric meter system upgrade does not affect the gas meter infrastructure. In PG&E's original AMI application, PG&E justified its gas system technology and network provider, Hexagram, Inc. by stating that its technology provides functionalities that

> "Allow one-way or two way radio communication capability directly to each premise with PG&E gas service; use highly reliable and powerful licensed radio frequency communication channels owned by PG&E; provide 100 percent coverage for all gas customers in one system; has proven module battery backed by the best proposed warranty; provide daily gas usage with the potential for hourly data for selected customers; provide customer level tamper detection information; and enable messaging for smart thermostats, in-home displays, and home automation."[25]

Since PG&E's gas AMI system was approved in Decision 06-07-027, and that the SmartMeter Upgrade does not pertain to the gas AMI system, PG&E's $167 million claimed benefit of gas conservation is not contingent upon the approval of the SmartMeter Upgrade. PG&E's rebuttal testimony on this issue is unpersuasive and devoid of substantive support. Thus DRA recommends that the overall project benefit be reduced by $167 million.

3. PG&E Is Double Counting Its Energy Efficiency Gains

If customers do adopt HAN-enabled information feedback technology, and conserve electric energy, the $198 million worth of energy savings associated with the

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24 A.07-12-009, PG&E SmartMeter Upgrade Exhibit 2-2, p. 2-5, line 21-22.

25 A.05-06-028, PG&E AMI Project, Exhibit 8-1, Page 1-7, Line 9-21.

Upgrade should not be used to justify both the Upgrade cost and the shareholder incentive that PG&E would earn as the result of the Commission's Decision 07-09-043 on the shareholder risk/reward incentive mechanism for energy efficiency (EE) programs. The electric energy conservation benefits justify dollar-to-dollar the Upgrade project cost and the associated return-on-equity. If not properly accounted for, PG&E shareholders would earn another 12 percent on the same energy saving benefits. Therefore, DRA proposes that 12 percent of the energy conservation benefits be deducted, to reflect the shareholder incentives PG&E could have earned if the energy savings attributable to the Upgrade were not separately identified from those due to EE programs.

DRA believes that this treatment is proper. When $198 million worth of savings benefits accrue in PG&E's EE program portfolio, PG&E customers will have to pay 12 percent of that $198 million to PG&E shareholders "on commission" for the EE program performance. Since $198 million will already include shareholder earnings associated with the Upgrade, that 12 percent would be a double-payment to PG&E shareholders. This further reduces electric conservation benefits from $198 million to $174 million in PVRR.

DRA also recommends that the Commission recognize that the 6,458 GWh of energy savings needs to be properly accounted for in PG&E's energy savings goal and EE program portfolio evaluation for 2012 through 2030, in order to minimize double-counting and transaction costs for PG&E customers. This is consistent D.07-10-032, where the Commission required utilities to

> "integrate customer demand-side programs, such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner."[26]

And further states that

> "Integrating our numerous customer demand-side management programs will avoid duplication of efforts, reduce transaction costs and diminish customer confusion."[27]

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[26] D.07-10-032, p. 5.

DRA's proposed treatment of the double-counting of energy savings benefits to justify both the AMI deployment cost and shareholder incentive for energy efficiency performance is also consistent with PG&E's policy argument in support of the Upgrade as energy efficiency strategy. PG&E states that the incremental benefits of the Upgrade, would include "[e]nhanced energy information tools for residential customers allowing for increased energy conservation."[28] This benefit would, as PG&E asserts, allow PG&E to

> "expand upon the progress PG&E has made to date with its SmartMeter Program and will enhance PG&E's ability to implement a variety of future initiatives that correspond to the goals established in the EAP including energy conservation, reasonably priced electricity and natural gas, and reduced need for new generation facilities."[29]

To the extent that the Commission recognizes an AMI system as an energy saving tool, beyond the potential of an AMI system to deliver demand response, the treatment of energy savings should be consistent with Commission established policy on energy efficiency.

ii. Demand Response

1. Programmable Communicating Thermostats (PCT)

PG&E claims that the Upgrade will deliver additional benefits to its air conditioning direct load control ("AC Cycling") program approved in D.08-02-009, because of the Upgrade meters' potential to communicate with Title 24 programmable communicating thermostats (PCTs). The Commission should reject the incremental benefits PG&E incorporates into its cost-benefit analysis in its entirety, ($129 million in PVRR) which it erroneously uses to partially justify the Upgrade application.

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[27] D.07-10-032, p. 6.

[28] A.07-12-009 PG&E SmartMeter Upgrade Exhibit 1, p.3, line 1-2, and p.20, line 15-16.

[29] A.07-12-009, PG&E SmartMeter Upgrade Exhibit 1, p. 14, line

i) strange history indeed

The history of PG&E's statements regarding this issue is one of lack of foresight, good planning or common sense. Its statements in various proceedings appear contradictory, and an attempt to justify funding for technology that is unreasonably duplicative.

In support of the original AMI Project, PG&E claimed that its then-proposed system could potentially achieve end-use direct load control to provide demand response benefits. PG&E urged the Commission to approve the original AMI Project based on this potential, specifically,

> "[b]ecause PG&E's selected AMI technology provides a two-way interface to each customer site, it allows for certain functional capabilities including… potential future communication with thermostats and load control switches at each customer site."[30]

Furthermore, PG&E argued in favor of the original AMI Project's ability to achieve the Commission's demand response goals. Specifically, because the original AMI Project

> "provides sufficient flexibility for future regulatory and market developments, **can accommodate a variety of end-use energy management devices to achieve load control objectives**, has a sufficient historical track record to mitigate the risk of system non-performance, delays, or cost overruns, and offer the best financial value."[31]

Although PG&E did not include the cost of end-use control devices for direct load control in its original AMI Project, it claimed that one value of the original AMI Project was its ability to accommodate direct load control programs, such as Air Conditioning (AC) Cycling.

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[30] A.05-06-28, PG&E Opening Brief, p. 13-14.

[31] A.05-06-28, PG&E Opening Brief, Section 1.1 and 1.2.

Arguing then in favor of a Critical Peak Pricing (CPP) program over an AC Cycling program, PG&E claimed that its CPP program could offer comparable peak load reduction on hot days. Specifically, PG&E argued that even if an AC Cycling program could deliver additional peak load reduction, the incremental load reduction would not likely offset the higher AC Cycling program administration costs. The CPP program was to alleviate peak load due to AC usage, specifically

> "PG&E has focused on a target market of residential customers with significant air conditioning loads. According to PG&E witness Faruqui, the SPP identified these customers as being among the most likely to provide significant demand response contributions. Therefore, PG&E has focused on marking the CPP tariff attractive to these customers (as well as planning on target marketing to this market segment.)"[32]

Furthermore,

> "As PG&E witness Corey Mayers noted: 'The results of the statewide pricing pilot indicate that for a customer already subject to CPP, and incremental fall in energy consumption can be expected to be generated by the introduction of a smart thermostat. However, PG&E determined that this increment was insufficient to justify the cost of deploying technology such as load control switches at this time, so elected not to include load control technology as part of its initial deployment.' "[33]

Less than one year later, PG&E filed its Air Conditioning Direct Load Control Application 07-04-009, and reneged on its previous assertion that the incremental load reduction due to enabling technology does not warrant a more expensive direct load control program. PG&E urged the Commission to approve its AC Cycling program, and allow simultaneous customer participation in both CPP and AC Cycling, stating that:

> "It is also very likely that allowing AC Program participants to also join the CPP program will result in additional DR beyond that provided in the AC Program… Indeed AC direct

[32] A.05-06-028, PG&E Opening Brief, p. 86.
[33] Ibid.

> load control devices are an enabling technology that will assist CPP customer's response to CPP events"[34]

Thus, PG&E first used CPP benefits to justify the original AMI Project, then it argued that whatever incremental demand response benefits that could be reaped by placing CPP participants in AC Cycling should be attributed to the AC Cycling program.

Responding to TURN and DRA's skepticism regarding how the AC Cycling Program could integrate with AMI, PG&E argued that:

> "DRA incorrectly claims that adoption of the AC Program will create 'inefficiency and disjointed technology' due to a potential request by PG&E to upgrade its AMI Program." [35]

PG&E further stated that it is unwise to implement the AC Cycling program based on the AMI Upgrade Project. Specifically,

> "DRA's and TURN's request for a delay based on a potential AMI upgrade is unwarranted and speculative. As mentioned… the technology and timing of two-way communication using the yet-to-be proposed HAN gateway is uncertain. On the other hand, PG&E has proposed a reliable and relatively inexpensive one-way communication system for its AC Program that is proven and is being implemented successfully already. The devices that PG&E is installing under the AC Program will continue to be triggered using the one-way paging system throughout the useful equipment life. There is no evidence in the AC Program Proceeding: (1) when HAN will be available in PG&E's service area; (2) when load control devices compatible with HAN would be available; and (3) the price of such devices. Thus a request to delay the AC Program that presumes evidence on these issues is unsubstantiated and justified."[36]

PG&E needs to remain consistent in its position, and the above history shows that it does not.

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[34] A.07-04-009 PG&E Opening Brief, p. 11.

[35] Id., p. 5.

[36] A.07-04-009, PG&E Reply Brief, p. 6.

ii) Back to the present

PG&E's AC Cycling program, recently renamed "SmartAC," is a *dispatchable* demand response program that delivers peak load reduction via *direct load control* of customers' AC units. During summer peak events, PG&E would remotely and intermittently turn off customers' AC units. In the AC Cycling Application (A.) 07-04-009, PG&E proposed two ways to do this: (1) directly by turning the AC unit on and off using a switch installed on the AC unit, and (2) indirectly by setting the thermostat back 4 degrees Fahrenheit. In the Upgrade application, PG&E argues the Upgrade will add additional DR benefit to the SmartAC program, because

> "New Title 24 building code air conditioning standards are expected in 2012*. The new standards will require all new homes and retrofits requiring building permits for central air conditioning and heating to have Title 24 compliant PCTs installed. PG&E will target residential customers with the new PCTs for participation in PG&E's SmartAC Program. PG&E will also create a program to encourage existing air conditioning customers to initiate early retrofit of their standard thermostat with Title 24 compliant PCTs. All of these customers will be seamlessly integrated into PG&E's existing SmartAC Program although the temperature set points, event notifications, and the ability for customers to override events will be communicated through the HAN gateway."[37] (*The supplemental testimony Exhibit 7 changed the date from 2009 to 2012)

As background, the California Energy Commission (CEC) sets energy efficient building standards, and considered the installation of remote-controllable PCTs as a requirement for new home constructions and qualifying building retrofits. However, in January 2008, the CEC withdrew the proposed PCT requirement from its 2008 Building Standards. The PCT requirement had received negative mass media attention, and news articles on the public backlash appeared in major publications such as the New York Times and the San Francisco Chronicle.[38] The consideration of the PCT requirement in CEC building standards, as a result, has been deferred.

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[37] A.07-12-009, PG&E SmartMeter Upgrade, Exhibit 3-5, page 5-17, line 6-17.

[38] The news articles can be found at http://www.nytimes.com/2008/01/11/us/11control.html?scp=1&sq=thermostat&st=cse and http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2008/01/17/BARNUGIKF.DTL, respectively.

PG&E presumes the CEC will reconsider the PCT requirement, and will mandate it in its Building Standards by 2012. Based on this anticipation, PG&E claims that there could be more households in PG&E's service territory equipped with PCTs, particularly "all new homes and retrofits requiring building permits for central air conditioning"[39] that would need to comply with the presumed new mandate. PG&E treats these customers as an added pool of potential SmartAC program participants and attributes the associated DR benefit to the Upgrade. Inherent in this argument is the assumption that PG&E did not account for new home and load growth in its recent AC Cycling application, and that the Upgrade would help "rein in" those new homes to participate in the SmartAC program.

On the contrary, DRA points out that PG&E has already counted the participation of new customers in its AC Cycling Application. In fact, one of PG&E's main policy arguments for its AC Cycling Application was the following:

> "The AC program will help address the increase in residential AC use arising from the construction of new homes that, as Commissioner Peevey recently noted, are concentrated in the warmer inland areas of the state. PG&E anticipates adding approximately 85,000 new electric customers per year over the next several years. Of these new customers, approximately 75,000 will be new residential customers, with the remainder being new small and medium commercial customers. The strongest expected growth in the residential sector is predicted to be in the central valley and Sierra Foothills regions, which have high summer temperatures and heavy AC loads."[40]

The new homes, as PG&E points out, may likely have heavy AC load. These new homes would also be the same new homes that would need to comply with Title 24 PCT requirements, if the CEC were to revert its position on Title 24 PCT requirements. PG&E's prepared testimony for the AC Cycling application was amended as late as October 10, 2007, two months before PG&E filed the Upgrade application. In two months, PG&E then recycled the same argument to justify the Upgrade. It cannot be both true that (1) PG&E *had* accounted for SmartAC program participation among new

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39 A.07-12-009 PG&E SmartMeter Upgrade Application, Exhibit 3-5, page 5-17, line 7-8.

40 A.07-04-009 PG&E AC Direct Load Control Application, Amended Prepared Testimony dated October 10, 2007, p. 1-6 to 1-7.

homes in the AC Cycling application, and two months later (2) PG&E *had not* accounted for SmartAC program participation among new homes, and needed to account for it in the Upgrade application.

The Commission should reject PG&E's claim that, with the Upgrade, it could "seamlessly integrate" new participants into the existing SmartAC program. DRA questions whether PG&E can "seamlessly integrate" the HAN functionality with its SmartAC program operation as it claims. Operating the SmartAC program through the HAN interface does not mean that PG&E can replace the 900 MHz paging system approved for its SmartAC program. In fact, PG&E states in the Upgrade testimony that:

> "Separate communications systems are likely to be necessary due to the possibility that customer-owned equipment installed under the current SmartAC program may not be able to communicate with the new HAN network."[41]

In other words, PG&E may not be able to operate all AC units participating in its SmartAC program through the HAN interface. PG&E has already successfully sought Commission approval of the SmartAC program, based on PG&E's argument that it could ameliorate increasing AC load among new construction, and that:

> "both PCTs and [AC] switches can be readily integrated with the so-called "smart meters" that it is rolling out in place of traditional meters as part of its advanced meter initiative (AMI) approved in D.06-07-027."[42]

As approved in D.08-02-009, PG&E has a communication system to remotely control PCTs. DRA points out that, during the period when the CEC was considering the Title 24 PCT requirement, it had proposed an AM/FM communication protocol. To promote interoperability, the CEC also considered requiring the PCTs to incorporate "communication expansion ports," to allow for remote control of the PCTs via other communication systems, such as the 900 MHz paging system for which PG&E received ratepayer funding in D.08-02-009. Even if the CEC were to revert to mandate Title 24 PCT in new construction, its focus on technological interoperability (which both DRA and PG&E have publicly supported) would likely persist. The Upgrade would not add an

[41] A.07-12-009 PG&E Exhibit 4-3, page 4-4, foot note [2].
[42] D.08-02-009, page 5, line 1-3.

incremental functionality to PG&E's existing demand-side management system, beyond what PG&E could already achieve with its functionality claims in the AC Cycling and the original AMI applications. From an integrated demand-side management perspective, PG&E has maximized its direct load control benefit claims, and should not use it again to justify the Upgrade.

PG&E attempts to argue that there would be *more* SmartAC participation *and* that the incremental participation would occur because of the Upgrade. As DRA discovered, participation among new homes was already counted in the AC Cycling application.[43] If there were more customers with PCTs because the CEC changes its position on the Title 24 PCT requirement, PG&E claims it would conduct targeted marketing among customers with the Title 24 PCTs. Targeted marketing *may* or *may not* attract more customers to join a program. Marketing can be done without the Upgrade. Having yet another technology for PG&E to remotely control customers' thermostats will not make customers more willing to surrender their thermostat control to PG&E. Not only does PG&E double-count the benefit it had already claimed in the AC Cycling application, it conflates the effect of marketing with the incremental functionalities of the Upgrade.

2. Peak Time Rebate (PTR)

In considering the demand response benefits PG&E attributes to the Upgrade proposal, the Commission should consider the metering functionalities needed to implement the proposed PTR program, and compare that to the added functionalities offered by the Upgrade. If PTR implementation does not depend on the added functionalities, particularly the HAN gateway and the integrated service switch, then the PTR costs and benefits should not affect the Upgrade cost-benefit analysis. DRA compared PG&E's PTR proposal to the functionalities of the Original AMI system versus the Upgrade, and concluded that PTR can be implemented without the added functionalities.

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[43] A.07-04-009 PG&E AC Direct Load Control Application, Amended Prepared Testimony dated October 10, 2007, p. 1-6 to 1-7.

To implement a Peak Time Rebate program as PG&E has proposed, PG&E needs to do the following:

(1) Notify customers the day before a peak event day, and
(2) Collect interval customer usage data, and compare usage on the event day to average usage of the previous three-of-five days.

DRA examined Commission records and PG&E's original AMI application prepared testimony exhibits, and concludes that the listed requirements for the proposed PTR program can be met with the already authorized AMI system. Based on the Original AMI system, customers could already elect to receive real-time information. In its Opening Brief, PG&E stated:

> "PG&E proposes two means in this initial deployment of AMI to allow customers to access and use the data available from the AMI system: (1) PG&E has proposed that all customers, including residential customers, be able to access their detailed usage patterns, through the previous day, on the Web. This access will enable customers to better manage their energy bills and participate in demand response and energy conservation programs. (2) PG&E proposes that all customers with demand usage over 200 kW be provided devices as part of AMI deployment that allows the customers to access their usage on a real-time basis. This group of large customer is most likely to invest in the energy management software to make efficient use of real time data devices. Other customers would not be precluded from obtaining the real time data devices."[44]

Furthermore, PG&E argued that its meters would support future rate designs:

> "The customer usage data recorded at the meter will be retrieved periodically throughout the day and stored in a database for future operational uses and in support of any required tariff design structure."[45]

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[44] A.05-06-28, PG&E Opening Brief, p. 61.

[45] A.05-06-028, PG&E Opening Brief, p. 14.

PG&E, in other words, does not require this Upgrade to achieve the same PTR goals. The $290 million PG&E includes in its benefits calculations should therefore be excluded.

As discussed in more detail in DRA's Exhibit 108, Ex. 5, Ch. 5B, DRA recommends that approval of the proposed PTR program should be separated from a review of PG&E's proposed AMI Upgrade system. Upon review of that program, however, DRA recommends that the Commission approve the PTR program with modifications in the 2009-2011 Demand Response Programs and Budget Application. Specifically, DRA recommends that the Commission adopt a two-level incentive structure to minimize free-ridership, as DRA recommended for SCE and SDG&E's PTR program proposals, and as adopted by the Commission for SDG&E's PTR program in Decision (D.) 08-02-034. Furthermore, PTR program measurement and evaluation should conform to the demand response load impact protocols adopted in D.08-04-050. Specifically DRA emphasizes the *ex post* assessment of free-ridership and the distribution of load impact across customers.

c. Other Benefits

PG&E, finding that interveners were coming up short on benefits associated with the AMI Upgrade, introduced yet another benefit in its rebuttal testimony. Mr. Vahlstrom proposed a security benefit of $520 million – conveniently sized to almost fill the gap between PG&E's identified costs and DRA's identified benefits (Ex.8, pg. 3-18, lines 6-8). He postulated that remote meter-reading would allow avoiding a "truck roll" every three years to reprogram the meters on site to integrate security and other software upgrades (Ex. 8, pg. 3-18, lines 13-20). The size of the benefit is highly dependent on the frequency of these truck rolls. Mr. Vahlstrom loosely defended the three-year interval based on DRA's mention of a seven-year replacement interval for head-end software (Ex. 8, pg. 3-18, lines 18-20).

In evaluating Mr. Vahlstrom's "eleventh hour" epiphany, one must be clear about what "status quo" reference point is being used to calculate the benefit. Indeed, the calculation of any benefit is always in reference to some other state. If benefits are to be calculated on an *incremental* basis relative to the DCSI-based AMI system examined in A.05-06-028, then the reference point is that system. If benefits are calculated on a *total* basis, including those achievable by the AMI system examined in A.05-06-028, then the reference point is the pre-AMI stock of electromechanical meters with no communications capability.

It should be obvious that the pre-AMI meters had no security problems other than a minor amount of energy theft. The meters were mechanical and did not include any components that could be reprogrammed. Hence, no truck rolls were required to change software for the entire stock of meters. The situation is similar with the DSCI system examined in A.05-06-028. Mr. Vahlstrom readily admitted under cross-examination that the DCSI system is relatively impermeable to security threats. As Mr. Vahlstrom stated, "there is not much you can do to hack a nonprogrammable device" (RT I, 130:13-15). Had there been a security problem, the business case evaluated in A.05-06-028 would have had to include an additional $520 million to cover cost of such truck rolls. There was no money included for this purpose (RT I, 110:25-28).

Mr. Vahlstrom stated that the DCSI system is relatively impermeable to security risks for two reasons. First, it is protected by its own obscurity. As Mr. Vahlstrom said "There are not very many people that know about it… And therefore, it's almost self-secured because most people can't get into the middle of it" (RT I, 133:13-18). Second, the DCSI system uses such a slow bandwidth that there are no Internet tools readily available to hack it. Mr. Vahlstrom said "it would take them four million years to run through all the combinations in a slow-speed system to try to test out anything you want to do" (RT I, 133:20-25). Mr. Vahlstrom added that the disconnect switches that are part of the upgrade make a system "much more appealing for people who want to do something" (RT I, 129:18-19).

Thus Mr. Vahlstrom's argument collapses into nothing more than a solution to a problem *created* by the enhanced functionality added by the AMI upgrade. It was not a problem with the system examined in A.05-06-028, nor with the pre-AMI meter stock. Thus this benefit does not belong in the benefits stream. But, given that the enhanced functionality brings about security concerns that didn't exist previously, it is reasonable to ask whether the higher cost of a remotely programmable meter is reasonable to include in PG&E's business case. Unfortunately, the added cost of remote programmability was made confidential by PG&E. But one can readily see that it is less than $520 million because PG&E's upgrade showing only includes $342 million for the meters *plus* the HAN and switches. Clearly the entire $342 million isn't associated with remote programmability alone.

Since the cost of such remote programmability is clearly less than its benefits, DRA believes this functionality is worth the cost. DRA adds, however, that the meters upon which its lower costs are based *are* remotely programmable. If there is anything about PG&E's proposed meters that do this function better than those that DRA assumed, such information simply is not in the record. This is an example of PG&E trying to "gold plate" its AMI system.

Having failed at including this $520 million security benefit in the business case, PG&E attempted on redirect examination to recast this benefit as one that will enhance its program offerings in other ways. Mr. Vahlstrom said, "there are anticipated to be lots of applications other than security that PG&E would be to be in a position to provide customers as the market develops." (RT I, 141:20-23) He went on to give the example of time clocks that are useful for time-of-use pricing. He stated that having time clocks in the meters is more practical than handling timing issues at the head-end (RT I, 143:1-5). The latter statement greatly obscured whether this is a legitimate incremental benefit given that previous systems evidently were able to accomplish the same thing. To the extent that such a benefit could be considered in the upgrade application, it would have to be capped at the presumably higher cost of handling the problem at the head-end. Yet no such information exists in the record.

To conclude, what started out as a security benefit morphed into a giant catch-all benefit that could encompass anything which PG&E could conceive. Such was the purpose of the so-called "societal benefits" already used to justify the first case. Whether there is anything incremental in this benefit is highly unclear.

VII. Cost Recovery and Revenue Requirement

a. Cost recovery

i. General Proposal

DRA proposes that the costs of the AMI upgrade be allocated to customers differently to what was adopted in PG&E's original application. DRA recommend that:

1. PG&E credit ratepayers with the benefits of the AMI project 8 months after meter costs are entered into the rate base, consistent DRA's settlement agreement with Southern California Edition Company in their AMI application (A.07-07-26).
2. PG&E track and report the differences between AMI benefits credited to ratepayers, of the Original and Upgrade AMI costs.
3. PG&E allocate the costs of the Upgrade using generation equal percentage of marginal costs (EPMC).

The first recommendation would require the Commission to modify D.06-07-027. The substantial delay in meter activation of the original AMI deployment indicates the need to modify the method by which benefits are credited to ratepayers. DRA also recommends that the Upgrade costs be allocated by generation EPMC, and recommends that the cost allocation method of the original AMI, $1.74 billion, be maintained as was adopted in Decision (D.) 06-07-027.

PG&E's benefits recognition proposal is described in its Exhibit 4 Chapter 1[46]. Currently, for each activated meter, PG&E credits ratepayers $1.77 per month to reflect operational savings not captured in the last general rate case (GRC). PG&E proposes to increase this amount by $0.1821 per month, for a total of $1.9543 per month for both applications. PG&E proposes to do this in year 2009 and 2010. After this, the operational saving from AMI would be reflected in the Test Year 2011 GRC.

PG&E experienced significant delays in the activation of the DCSI meters. Ratepayers currently fund PG&E's original AMI deployment costs soon after the money is spent, while the benefits are not being accrued. There is no reporting mechanism to track the difference between the operational benefits credited to PG&E's ratepayers and

[46] A.07-12-009, PG&E Exhibit 4-1, p. 1-4 to 1-5.

what PG&E showed in its business case for its proposed AMI Upgrade. As stated in Decision (D.) 06-07-027, TURN expressed the same concern that it "will be very difficult to tease out future rate cases whether the benefits forecast today actually materialize. (Opening Brief, p.62)."[47]

DRA recommends that PG&E track and report the differences between the AMI benefits actually credited to ratepayers and those shown in PG&E's business cases, for both the original and Upgrade applications. DRA recommends the Commission adopt a safeguard mechanism to ensure that ratepayers' risk is minimized if PG&E experiences further deployment delays. PG&E should automatically credit ratepayers with the benefits of both the original and Upgrade projects 8 months after meters costs enter into the rate base. This will ensure that ratepayer benefits are not delayed due to further deployment delays. Continuing the benefits recognition proposal adopted in the original AMI decision unfairly allocates a disproportionate share of the financial risks to its ratepayers. If ratepayers guarantee PG&E the funding for AMI costs, it is reasonable that PG&E uphold its end of the bargain, and keep the benefits promises.

b. Allocation of AMI Costs

In this application, PG&E proposes to allocate incremental AMI deployment costs with an EPMC distribution allocator. "Specifically, PG&E proposes to allocate the AMI Project revenue requirement in proportion to each rate schedule's current share of distribution revenue".[48] Under this proposal, the AMI revenue requirement allocated to residential customers would be approximately 55.1 percent.

Since PG&E justifies the Upgrade costs primarily on demand response and energy conservation benefits, DRA recommends that any Upgrade costs approved by the Commission be allocated by a generation allocator. Savings due to peak load reduction and energy conservation typically flow through an energy resource recovery account (ERRA), from which the account balance automatically flows to customer classes based

[47] D.06-07-027, p.50.
[48] Exhibit PG&E-5, Chapter 6, p.6-2.

on a generation allocator. This means that, if the potential benefits of the Upgrade do occur, the energy saving benefits would flow back to customer classes accordingly. For the residential class, the generation allocator is approximately 40.6 percent. Residential customers would receive 40.6 percent of energy costs. As the residential class would obtain 40.6 percent of potential benefits, it makes sense that they also pay 40.6 percent of the costs. PG&E's proposal to allocate AMI Upgrade costs by a distribution allocator would allocate 55.1 percent of these costs to the residential class. PG&E is thus recommending that residential customers pay far more than they would potentially benefit from the Upgrade. DRA recommends that the Commission allocate any approved Upgrade costs by generation allocators that would allocate approximately 40.6 percent of these costs to the residential class.

In the Original AMI application, PG&E proposed the allocation of the costs by a distribution allocator. DRA did not oppose PG&E's proposal as the majority of PG&E's identified benefits were for operational savings. DRA could have proposed a hybrid allocator of 85 percent distribution costs and 15 percent generation costs at that time, but did not do so, as most of the benefits were operational benefits.

Allocating the Upgrade costs by a generation allocator and the initial costs by a distribution allocator would still result in the residential class paying for over 50.1 percent of total AMI costs. This would be similar to the hybrid allocation that DRA has proposed in SDG&E's and SCE's AMI proceedings.[49] Therefore, DRA recommends that any approved Upgrade costs be allocated by generation allocators so that residential customers are allocated a percentage of the costs that is consistent with how benefits will flow to them. Under PG&E's proposal, residential customers would essentially pay for 55.1 percent of the costs while receiving only 40.6 percent of the benefits.

DRA believes that PG&E's proposed cost recovery unfairly allocates all financial risks to ratepayers. To rectify this problem, the Commission should modify the benefits

[49] DRA's hybrid allocator is constructed as a weighted average of a distribution allocator for operational cost benefits and a generation allocator for demand response benefits and energy savings.

recognition mechanism adopted in D.06-07-027, and allocate any approved Upgrade costs by generation EPMC.

VIII. Miscellaneous Issues

a. Water Utilities

DRA proposes that PG&E's SmartMeter Program™ facilitate the Automated Meter Reading ("AMR")[50] of its customers' water usage. It is DRA's belief that AMR provides cost savings mainly associated with water meter reading and assists as a tool to promote water conservation. However, at this time it is not clear whether PG&E's Upgrade includes or facilitates AMR for water usage. As indicated in DRA's Exhibit 108, Ex. 2, Chapter 1 (Ralph Abbott), facilitating water AMR is fairly easy to do at the meter endpoints. Also, the amount of additional information involved would not significantly tax the head-end hardware and software given that water meter reads generally only occur monthly. The largest issue is that of PG&E coordinating with the billing departments of various water utilities and providing billing data in an electronic form in a timely and secure manner.

As explained in more detail in Exhibit 108, Ex. 5, DRA believes there are additional incremental operational benefits/savings from automated reading of PG&E ratepayers' water usage.

Conventionally, PG&E collected data from residential ratepayers electricity and natural gas usage approximately once per month, which is similar to the current collection of PG&E customers' water usage. However, PG&E customers' water usage is collected by the respective water district, department, utility, or municipality. Once fully implemented, PG&E's SmartMeter Program™ will collect and store customers' electricity usage (every hour), and transmit that data a minimum of once per day. In addition, PG&E's SmartMeter Program™ can collect and transmit its customers' natural gas usage at least once per month. PG&E, however, plans to collect gas usage data for each customer on a daily basis.

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[50] Also called Automated Remote Meter Reading.

DRA accepts that water metering benefits need not be part of this proceeding, but urges the Commission to order PG&E to try to incorporate this potential benefit into its long term deployment, as SCE has agreed to do. The transmittal of customers' water consumption data provides numerous ways to measure, store, and forward information over a network for use by customers, grid operators, and utilities.

PG&E initially selected the Power Line (PL) communication system for electric usage, which is not well suited for natural gas or water AMR. PG&E is using a separate radio frequency ("RF") system by Hexagram for natural gas AMR, which is well suited for water AMR and is currently in use by many water utilities.[51] There are many examples of combined electric, natural gas and water AMR, but these are primarily by municipal utilities. DRA believes the RF system could be utilized for water AMR in areas where

[51] DRA understands that SDG&E has started a pilot program for water AMR in its service territories, and that the City of Colorado Springs has installed such a system.

PG&E provides natural gas service and where there is metered water service.[52] DRA believes there are very few technical impediments to adding water AMR to PG&E's selected RF system for natural gas usage.

It is possible that some water companies may not be interested in water AMR because they do not believe it would be cost effective. Some water companies have a small number of customers, which could make it difficult to recover costs associated with water AMR. However, there are about twenty water companies operating in PG&E's service territory with greater than 25,000 customers where AMR application could be cost-effective.

DRA concludes that PG&E should further investigate the cost effectiveness of augmenting its SmartMeter Program™ to allow remote reading of customers' water usage while maintaining the privacy of customers' usage information. PG&E should hold workshops, as SCE has agreed to do in its AMI settlement, to explore issues related to AMI for water utilities.

IX. CONCLUSION

In light of the above, DRA respectfully requests that the Commission reject PG&E's Upgrade proposal on the ground that it is not cost-effective as proposed.

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52 It should be noted that SCE currently uses AMR for natural gas and water usage for the City of Long Beach.

Respectfully submitted,

/s/ PAUL ANGELOPULO

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August 29, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document "**OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES** in **A.07-12-009,** by using the following service:

[**X**] **E-MAIL SERVICE**: sending the entire document as an attachment all known parties of record who provided electronic mail addresses.

[ ] **U.S.MAIL SERVICE**: mailing by first-class mail with postage prepaid to all known parties of record who did not provide electronic mail addresses, if any.

Executed on **August 29, 2008**, at San Francisco, California.

/s/ REBECCA ROJO

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Rebecca Rojo

N O T I C E

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* *

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