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Decision 09-03-026 March 12, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

(See Appendix A for a list of appearances.)

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED UPGRADE TO THE SMARTMETER PROGRAM

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DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED UPGRADE TO THE SMARTMETER PROGRAM

1. Summary

By this decision, we authorize Pacific Gas and Electric Company (PG&E) to proceed with its proposed SmartMeter Program Upgrade at a cost of $466,760,000, subject to the conditions specified in this decision, and to increase revenue requirements to recover the related costs.

The principal components of this electric meter upgrade include an integrated load-limiting connect/disconnect switch, a home area network gateway device and an advanced solid state meter. With the authorization of the upgrade to PG&E's previously authorized advanced metering infrastructure program, the devices and functionalities are now comparable to that previously authorized for San Diego Gas & Electric Company and Southern California Edison Company.

Briefly, the decision:

- Adopts PG&E's incremental meter device cost estimates.
- Reduces incremental cost estimates for certain retrofit, demand response program, project management, information technology, operation and maintenance and technology assessment costs, along with related contingencies.
- Determines that, on a present value revenue requirement basis, the upgrade is cost effective.
- Adopts a two-tier peak time rebate for PG&E and defers the design of the incentive and funding of the program to PG&E's November 2009 rate design window filing.

- Denies a request to exclude street light customers from the rate increase.

- Orders PG&E to pursue automated meter reading for water meters, by working with the water utilities in its service territory, either through multi-party workshops or direct dialogue.

This proceeding is closed.

2. Background

The Commission opened Rulemaking 02-06-001 as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment.[1] PG&E's Application (A.) 05-06-0281 emerged from the Rulemaking and was PG&E's proposal for full deployment of an advanced metering infrastructure (AMI).

By Decision (D.) 06-07-027, the Commission authorized PG&E to deploy its AMI project, which included automation of its gas and electric metering and communications network (5.1 million electric meters and 4.2 million gas meters) and consisted of metering and communications infrastructure as well as the related computerized systems and software. Most of the meter inventory was to be retrofitted with communications modules and redeployed.[2] The Commission adopted as reasonable a project budget of $1.7394 billion, inclusive of a risk based allowance, or contingency, of $128.8 million and $49 million for pre-

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[1] *Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing*, filed June 6, 2002 and closed by D.05-11-009.

[2] D.06-07-027 indicates that PG&E's plan was to retrofit 54% of the existing electric meters and 96.1% of its existing gas meters.

deployment costs approved in D.05-09-044. The Commission also adopted PG&E's rate proposal for critical peak pricing (CPP) tariffs.

The authorized AMI project was cost effective in that the present value revenue requirement (PVRR) of the project costs, $2,258.3 million, was more than offset by the sum of the PVRR of operational benefits, which amounted to $2,024.2 million, and the PVRR of the demand response benefits associated with the CPP tariffs, which amounted to $338 million.

Since the approval of PG&E's SmartMeter Program the market in this area has evolved rapidly. PG&E believes that the pace of this development was enhanced by the approval of PG&E's SmartMeter Program which signaled greater opportunities for vendors of advanced metering equipment, communication technology and in-home devices needed to support utility advanced metering initiatives. Further incentive has been provided by the applications of the other major investor-owned utilities (IOUs) in California for AMI programs. PG&E states that the result, since the approval of its original SmartMeter Program, has been substantial innovation and significant reductions in cost.

On December 12, 2007, PG&E filed A.07-12-009, the focus of this decision, requesting authority to further increase rates related to its AMI project (now referred to as its SmartMeter Program) in order to upgrade three elements of its SmartMeter Program technology. The three elements of the SmartMeter Program Upgrade (or Upgrade), are:

- Incorporating an integrated load-limiting connect/disconnect switch into all advanced electric meters;

- Incorporating a Home Area Network (HAN) gateway device into advanced electric meters to support in-home HAN applications; and

- Upgrading PG&E's electric meters to solid state meters to support the above functionality and to facilitate upgrades.

PG&E states that through this SmartMeter Program Upgrade, it will create a foundation for building an infrastructure that will enable and empower new ways of looking at energy use. New possibilities exist in the areas of energy efficiency, customer satisfaction and system reliability.

PG&E estimates $572,453,000 in Upgrade costs that are incremental to those costs authorized by D.06-07-027. The PVRR of the incremental costs is $841,157,000, which is offset by incremental operational, conservation and demand response benefits estimated by PG&E to be $1,063,124,000 (PVRR).

A prehearing conference was held on February 8, 2008, and the Assigned Commissioner's Ruling and Scoping Memo was issued on March 13, 2008. The Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), and the California City-County Street Light Association (CAL-SLA) each issued testimony on June 30, 2008. PG&E and the City and County of San Francisco (CCSF) each issued rebuttal testimony on July 23, 2008. Evidentiary hearings were held from August 4 through August 8, 2008. Opening briefs were filed by August 29, 2008. Reply briefs were filed by September 12, 2008, at which time this proceeding was submitted for decision.

3. PG&E's Request

In its application, PG&E specifically requests that the Commission:

1. Approve PG&E's SmartMeter Program Upgrade for construction and deployment as described and proposed;

2. Allow PG&E to recover the actual costs of the Upgrade without further reasonableness review if the actual cost of the Upgrade is less than or equal to $623 million[3] and to recover additional reasonable amounts, if any, upon appropriate Commission review;

3. Adopt PG&E's proposed balancing account and other ratemaking mechanisms to track actual costs and pre-approved benefits of the Upgrade;

4. Adopt PG&E's proposal of using forecast benefit amounts, as presented in this Application, tied to the actual project deployment schedule, for providing operating benefits of the Project to customers, and also recognizing other benefits associated with demand response and energy conservation;

5. Approve the Upgrade forecast revenue requirements presented in this Application as the starting point for Project rates; and

6. Adopt PG&E's proposal for changing electric rates on January 1, 2009 and on January 1, 2010, based on the approved forecast revenue requirements, combined with balancing account balances that true-up for actual costs and credited benefits estimated for each rate change date, and any other permission and authority necessary to implement the proposed rates.

As part of this proceeding, PG&E also requests authority to implement its peak time rebate (PTR) proposal and recommends a single tier tariff to do so.

4. Positions of the Other Parties

Briefly, the positions of the other parties are as follows:

4.1. DRA

[3] Since revised to $572 million.

DRA recommends that PG&E's Upgrade proposal be rejected, arguing that it is not cost-effective. While DRA estimates that the advanced meters with the HAN gateway device, integrated load-limiting connect/disconnect switch and communication device can be procured at a substantially lower cost than estimated by PG&E and maintains that certain other costs estimated by PG&E related to project management, meter retrofits and technology assessment are excessive, its estimates of benefits do not cover its estimates of adjusted costs. DRA accepts PG&E's estimate of operational benefits and a portion of electric conservation benefits, but for various reasons rejects PG&E's estimate of gas conservation benefits, PTR benefits and Title 24 programmable communicating thermostat (PCT) benefits for use in evaluating the cost effectiveness of the Upgrade. DRA also proposes a two tier PTR rate design as opposed to the single tier proposal by PG&E. DRA also recommends that PG&E should further investigate the cost effectiveness of augmenting its SmartMeter Program to allow remote meter reading of customers' water usage for the larger water companies in PG&E's service territory.

4.2. TURN

TURN recommends that the Commission reject this application, asserting that (1) the operational benefits of the Upgrade project do not justify its costs, and the program is highly unlikely to produce the demand response benefits that PG&E expects; and (2) the AMI system with the HAN technology is expected to obtain the same demand response benefits that would have been obtainable with a cheaper, less risky air conditioner (AC) cycling switch and it would be unreasonable to spend $572 million dollars for such results.

If the Commission proceeds with any part of the application, TURN proposes that failure by PG&E to achieve 65% of the megawatt (MW) savings approved in D.06-07-027 and 100% of the additional PTR and PCT MW savings projected in this application should result in penalty payments to ratepayers.

4.3. CCSF

CCSF opposes PG&E's request for a number of reasons including poor technological choices in the original AMI proposal, little evidence to show the estimated benefits will actually occur, and its perception that the actual deployment of meters is not commensurate with the amount of money spent so far on the project.

With respect to DRA's recommendation that PG&E investigate the possibility of remotely reading water meters for water companies within its service territory, CCSF agrees that, to the extent feasible, water and electric utilities should be cooperating and working together in the best interests of their common customers. Because the City's water utility is in the process of implementing its own AMI system, the City indicates it is willing to work with PG&E to avoid system redundancy.

4.4. CAL-SLA

CAL-SLA opposes PG&E's proposal to increase street light rates for the Upgrade costs, because SmartMeters won't be installed in street lights and there are no demonstrated and proven cost benefits to the street light class.

5. Choice of Technologies

As indicated, there are three principal elements to PG&E's Upgrade request – the HAN gateway device, the integrated load limiting connect/disconnect switch and the advanced solid state meter. The devices are described below. DRA supports the deployment of these particular devices, as long as it is cost effective to do so.

5.1. HAN Gateway Device

The HAN gateway device will enable two-way communications directly into a customer's home. A key feature of the new communications technology will be to give customers near real-time access to their energy usage data. PG&E envisions this technology will enable it to send time and price indicators to the customer's meter, giving the customer the opportunity to participate in demand response, time of use (TOU), and other energy management initiatives. PG&E provides the following support for deployment of the HAN device:

- The emerging home area network technology is integral to the future of energy usage, conservation and management. In the future, appliances and other energy using devices will be more intelligent than they are today. To take advantage of this intelligence, the appliances will need to receive a signal regarding the price and availability of electricity. The HAN gateway device would provide the capability to transmit the information from the meter to these smart appliances, energy management systems and other energy using devices. The HAN gateway device that PG&E would deploy is the bridge between PG&E's network and the customer's home area network. The gateway device will facilitate customers' management of their energy usage via their connection to PG&E's network and the information that will travel among the devices in the residence, the customer's meter and PG&E.

- The HAN gateway device will position PG&E with a platform that has the potential to communicate with programmable communicating thermostats that are expected by PG&E to be required by the California Energy Commission (CEC) through Title 24 in all new and selected existing premises beginning in 2012.

- The HAN gateway device in combination with the solid state meter and AMI will enable PG&E to better respond to load reduction directives issued by the California Independent

> System Operator (ISO). This is because PG&E will be able to confirm the fact that key energy using devices have responded and will aid in the quantification of the amount of demand response achieved. This capability would support the minimization of the discount factor that is currently applied to some demand response programs when PG&E files its resource adequacy plans. Timely and affirmative verification of load reduction will lead to better forecasting, increased understanding of program performance and a reduction in resource procurement.

5.1.1. CCSF's Position

CCSF argues that the Commission should not approve PG&E's Upgrade to the extent PG&E would install HAN gateway devices in all of its electric meters. According to CCSF, the technology PG&E seeks to deploy is not yet commercially available, and PG&E cannot guarantee when its chosen endpoints will be available for deployment at all, let alone in sufficient quantities for PG&E to deploy nearly five million meters on a timely basis. CCSF adds that the industry has still not set standards for HAN connectivity, and it is very possible that PG&E will deploy five million devices that do not meet the eventual standards and will require upgrading again in a few years.

CCSF also states that the HAN system need not be included in the meter, but instead could be separate from the meter. According to CCSF, deployment in this manner, rather than through the endpoints, would insure that the costs of acquiring a HAN network are appropriately allocated to those customers who would chose to purchase such a network because they are likely to benefit from HAN products and services.

Finally, CCSF states that San Francisco residents are not likely to be among those who would benefit from HAN technology for two reasons. First, there is a larger percentage of renters and persons living in multiple dwellings in San

Francisco than there is in the rest of the State of California. According to CCSF, these types of customers generally use less energy than other residential customers, and might not want to incur the expense to purchase HAN-enabled appliances. Second, because of its climate, San Francisco residents are less likely to have central air conditioners, which would be one of the primary sources of reduced electrical use.

Regarding CCSF's first argument, PG&E states that CCSF ignores the fact that the Commission has already found that the time is ripe for SDG&E to deploy HAN devices[4] and the Commission has issued a proposed decision[5] that would authorize SCE to deploy HAN devices. According to PG&E, in order to promote statewide consistency for this developing industry, the timing is excellent for PG&E to work with SDG&E and SCE and to deploy devices with consistent standards. PG&E adds that CCSF's argument also ignores the work proposed by PG&E in the Upgrade to shape the development of this burgeoning industry and to ensure that there is a statewide open standard for HAN communication systems that is secure, upgradeable and extensible.

Regarding CCSF's second argument on the merits of a stand-alone HAN device, PG&E asserts that it lacks evidentiary support, in that CCSF's argument finds its source in the study of SmartMeters conducted by CCSF that was excluded from the record of this proceeding.[6] According to PG&E, while the

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[4] D.07-04-043.

[5] A final decision, D.08-09-039, was issued, and authorizes SCE's deployment of HAN devices.

[6] In an oral ruling, the administrative law judge denied the request of CCSF to leave the record open for the purpose of considering an upcoming study on PG&E's SmartMeter

Footnote continued on next page

administrative law judge clarified that "[m]uch of the information in the contemplated study as it relates to the testimony submitted in this proceeding can be provided by the City to the Commission through the briefing process," there is no testimony submitted in this proceeding on the value of stand-alone HAN devices; and CCSF's argument is thus substantively and procedurally improper and must be rejected.

Regarding the third argument, PG&E states that CCSF ignores the fact that renters have financial incentives to reduce their energy costs, just as owners do. PG&E believes that all customers, whether they are renters or owners, deserve the opportunity to use HAN devices to reduce their energy consumption and that it is good public policy to promote such reductions.

5.1.2. Discussion

This is an appropriate time to authorize deployment of HAN gateway devices for PG&E. PG&E's request to do so is reasonable. We have already authorized such deployment for both SDG&E and SCE, and to do for PG&E would ensure statewide consistency as long as their efforts are coordinated. We feel such consistency is important in providing a basis on which the HAN technology can efficiently develop and for providing a large market force that can be influential in developing appropriate standards. Also, as part of this decision, we authorize funds for PG&E to continue to work with the other utilities is California and throughout the United States to establish standards for HAN technology and applications. In authorizing deployment of HAN devices

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Program that would be conducted by certain departments within CCSF. *See* 5 RT 779-781.

for PG&E at this time, we feel reasonably assured that the utility will be able incorporate this evolving technology in its meter deployment plan.

We are unable to judge the merits of a stand-alone HAN gateway device. As indicated by PG&E, there is no evidentiary record in this proceeding regarding such a device, since this issue was raised by CCSF in its opening brief that was filed on August 29, 2008. The proper time to have raised this issue was June 30, 2008 when intervenor testimony was due. That would have allowed time for discovery and rebuttal testimony and provided the opportunity for cross-examination by other parties during evidentiary hearings. That being said, if a customer has no need for the HAN gateway in the meter, and if a stand-alone HAN system is available, we see no reason why that customer should not have the opportunity to purchase and use such a system separately from the HAN gateway provided by PG&E through its meter. The important point is that all customers should have the opportunity to use HAN devices to reduce their energy consumption, and it is good public policy to promote such reductions. However, for that same reason, customers should have the opportunity to use the HAN gateway through PG&E's meter, and we feel the most cost effective way to provide that access, over the long term, would be through PG&E's meter deployment plan rather than through random retrofits.[7]

To facilitate the HAN concept, PGE should work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness

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[7] Evidence in this proceeding indicates that the incremental costs of installing a HAN gateway device after the meter and disconnect switch have already been installed is

Footnote continued on next page

of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

5.2. Load Limiting Switches

PG&E explains that when it developed its original AMI application in 2005 (A.05-06-028), the most cost-effective option for remote meter "turn-on/turn-off" was to add a "connect/disconnect collar" mounted separately and in conjunction with the electromechanical meter. Thus, PG&E's original project included adding a connect/disconnect collar to 600,000 electromechanical meters. Because of advances in solid state meter and load limiting switch technology, as well as decreases in the relative costs of the components, PG&E now proposes to install integrated load limiting switches for all of PG&E's residential and single phase, 200-amp, self-contained meter customers. PG&E provides the following support for deployment of the integrated load limiting switch:

- It is important to provide all residential electric customers with a load limiting switch, not just the 600,000 envisioned in the original AMI Application, so that the PG&E's customers, the utility and the state of California (State) can benefit from the increased functionality provided by the new switches. The new load limiting switches provide significantly more functionality compared to the collar associated with the electromechanical meters. That is because the switch built into the collar was designed as an on/off toggle, was not integrated into the metrology of the meter and, therefore, provides no real opportunities for load limiting and energy management

nearly nine times the cost of the HAN gateway device. For example, see Exhibit 8WC, the eighth page (unnumbered) of the Appendix 10-1 workpapers.

programs. On the other hand, the load limiting ability of the new switch is created by the joining of a programmable connect/disconnect switch with an intelligent solid state meter and integrating these components with the two-way communications capability delivered by PG&E's AMI system. The switch will enable the development of different options that will allow customers and PG&E to control not just whether the power is on or off, but how much power can be used at any given time, and this combination of technologies results in adjustable load limiting capabilities around which a variety of programs and/or rate offerings can be designed to take advantage of this flexible energy service control tool.

- The increased functionality of the load limiting switch will also help PG&E and the State in designing and implementing improved demand response programs that will reduce overall energy usage, will reduce load on the system and will improve overall reliability of the system. The presence of load limiting switches could help the ISO and PG&E to provide area-wide and system-wide relief during peak usage periods without completely shutting down critical systems. This view is corroborated by the Federal Energy Regulatory Commission (FERC) in their 2007 Assessment of Demand Response and Advanced Metering report which states, "remote connect/disconnect may also be valuable for its ability to avoid extended outages and overloading of transformers at critical peak by allowing grid operators to disconnect customers where lines are stressed. The ability to ensure less energy is used by PG&E's customers in capacity or infrastructure constrained areas will lead to fewer customer outages, fewer required distribution assets and less generation.

5.2.1. CCSF's Position

CCSF states that PG&E appears to be putting forth the ability to limit load to essential services through the endpoints as a means of "keeping the lights on" to some degree, rather than incur rolling brown or black outs, and this explanation would appear to include the belief that this feature will curtail the use of video games and other non-essential electrical uses. CCSF argues that these load-limiting switches reduce loads indiscriminately, and it would be incumbent on PG&E's customers to choose how they will use the reduced amount of electricity that PG&E would make available. According to CCSF, customers, especially small customers, with little in the way of non-essential load, still would have paid the price for instituting measures to control loads used by higher energy users.

CCSF also states that there is no evidence in the record that the software required to effectively manage these load limiting switches is presently available, or even that it is expected to be available any time soon.

It is CCSF's position that, since it appears that PG&E's remote connect/disconnect switch is an investment that PG&E has only proven to have operational value when used with delinquent customers, there is no reason that the Commission should authorize PG&E to install this functionality on all residential meters.

In response, PG&E states that CCSF ignores the evidence provided by PG&E that explains the variety of benefits available from these devices. First, the devices provide PG&E with the ability to remotely connect or disconnect customers. Second, the devices provide PG&E and state officials a platform upon which to design new rate options for customers. Third, the devices would give greater control to the ISO and PG&E to provide area-wide and system-wide relief during peak usage periods without completely shutting down critical systems. This should result in fewer, or shorter, outages. PG&E adds that the operational benefits from the first category alone amounts to over $150 million (PVRR), an amount that has not been challenged.

5.2.2. Discussion

We agree with PG&E that the increased functionality and the potential uses of the integrated load limiting connect/disconnect switches justifies providing all electric residential customers with such switches. This functionality could be used to implement certain demand response programs and to provide area-wide and system-wide relief during peak usage periods. Such opportunities are in the public interest and are not available under PG&E's original AMI program. Also, the integrated load limiting connect/disconnect switch provides significant incremental operational benefits related to field technician labor savings for connect/disconnect services.

Finally, we note that CCSF raised the issue regarding the availability of the software required to effectively manage the load limiting switches in its opening brief. We also note that CCSF does not provide any reason why it believes that the necessary software does not exist or will not exist soon. This issue should have been raised in prepared testimony so that an evidentiary record could be developed through rebuttal testimony and evidentiary hearings. In its testimony, PG&E has acknowledged that modifications and interface changes will be required to create new credit/collection templates, start/stop algorithms, and partial load limiting functionality[8] and has included such costs in its information technology system integration chapter.[9] While nothing is certain, PG&E is taking reasonable steps to ensure the effective operation of the integrated load limiting connect/disconnect switches.

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[8] In this proceeding, PG&E has not proposed to implement any of the load limiting capabilities of these switches, but rather only the connect/disconnect capability.

[9] *See* Exhibit 3, Chapter 4, pp. 4-5 through 4-6.

5.3. Advanced Solid State Meter

In PG&E's original AMI Application, PG&E proposed deployment of electromechanical electric meters for the majority of its residential electric service customers. The remainder of the residential as well as all commercial customers would receive solid state meters. According to PG&E, for deployment to date, this meter mix has worked as intended and, accordingly, has met the objectives of PG&E's original AMI Application. In the current application, PG&E proposes a transition in this mixture to the deployment of solid state ubiquitously. PG&E states that the solid state meter will be the platform for the intelligent, integrated metering solution that will enable PG&E to provide a number of new capabilities including a HAN gateway device (enabling price signals, load control and near real time data for residential electric customers) and load limiting disconnect switches. All of these things, and potentially more features in the future, are possible because of the increased processing power, memory storage, programmability, and upgradeability provided by the solid state meter platform. PG&E provides the following support for deployment of the advanced solid state meter:

- As PG&E and other utilities demonstrate the need for, and interest in, advanced metering technology to support their advanced infrastructure projects, the industry's vision has expanded, the functionality of the new meters has increased and the prices for solid state meters and other integrated components have decreased. The current generation of solid state meters is programmable, have additional data storage capacity and possess processing capabilities that will expand both the usefulness and the reliability of the meter. Unlike electromechanical meters, current generation solid state meters are the only meters that have the native capability to support communication with HAN and the integrated load limiting switch.

- As a result of the advanced processing capabilities and the memory built into the solid state meter, as well as the communications provided by PG&E's AMI communications network, PG&E will be able to upgrade meter functionality remotely by communicating changes to a combination of both the software and the firmware inside the solid state meters, thus taking advantage of how these devices are designed. The capability to upgrade the meter (as well as the AMI and HAN devices) gives PG&E greater flexibility to respond to changes in technologies and marketplace developments and helps to "future-proof" these technologies.

- The increased memory at the meter device will provide a platform for more reliable data integrity. The increased reliability results from the ability to store more data at the meter device, data that can be specifically identified with the residence before it is centralized with other information in PG&E's databases. Because some historic usage data will also reside at the meter device, PG&E anticipates that this will provide an alternate source of data to resolve various customer billing issues.

- Additionally, because of the increased memory at the meter device, PG&E will be able to collect greater amounts of usage data which could support valuable research studies. Such studies could provide useful information to PG&E in support of a variety of operations and maintenance procedures and could be used to develop studies that PG&E anticipates would be valuable to the ISO, other agencies and the State as they work to manage distribution grids and electricity consumption.

No party disputes the technological merits of the advanced solid state meter or PG&E's decision to deploy it ubiquitously as part of the Upgrade. PG&E's decision to do so is reasonable.

5.4. Network Technologies

As part of its original AMI proposal in A.05-06-028,

> PG&E selected Distribution Control Systems, Inc. (DCSI) to provide a Power Line Carrier technology for electric meters and Hexagram, Inc. to provide a fixed network system with radio frequency communication channels owned by PG&E for gas meters. These selections followed a detailed Request for Proposal (RFP) and evaluation process. PG&E's testimony showed that the DCSI system has been deployed by a number of other utilities (none as large as PG&E) to provide a sufficient demonstration of the technology's reliability and functionality. The technology provides two-way communications to each customer's meter. The technology also allows other functions including direct polling to the meter by PG&E which can assist in completing customer service related requests; and it has the potential for direct communication with in-home devices like thermostats and load control switches."[10]

PG&E indicates that it is evaluating the possible implementation of an enhanced communication network, which would be implemented without seeking any additional costs for that network in this application, and would provide greater benefits than the power-line-carrier technology discussed in A.05-06-028.

5.4.1. DRA's Position

While DCSI employs a power line carrier technology, Hexagram's technology is radio frequency (RF) based. DRA understands that PG&E is considering a Silver Springs Networks RF technology to replace the DCSI power line technology for electric customers. DRA does not believe that two separate and overlapping RF networks, one for gas and a separate network for electric are well advised. DRA states that a single RF system by various vendors, including

[10] D.06-07-027, pp. 18-19.

Aclara[11] RF or Silver Springs RF is capable of doing both. DRA is indifferent to the choice of Aclara RF versus Silver Spring RF, provided that the costs of the change and the additional costs of operating and maintaining two RF systems are not borne by ratepayers. According to DRA, a single RF system serving both the gas and electric metering requirements in all but the deep rural areas was the obvious choice from the outset of the PG&E project.

In response, PG&E states that DRA provides no evidence to support the contention that a single RF network is better than dual networks for gas and electric and also contradicts its own prior position on this issue.

PG&E states that the Upgrade seeks no funding for its network technologies, and the costs of managing its networks – including the change to a RF mesh network for electric – will be handled as part of the funding provided in the original AMI case. PG&E also states that despite DRA's opinion in the original AMI case that, "[m]ixed technology systems, tailored to the applications and as proposed by a number of highly competent firms, would ordinarily be a more attractive choice than stretching the capabilities of a single communications technology" and that the choice would ultimately come down to an economic one, DRA now contradicts its former position and attempts to assert that a single technology for the network is always a better choice. PG&E also adds that DRA's witness testified during the hearings that he did not perform any economic analysis comparing PG&E's proposed dual network infrastructure. Therefore, PG&E argues that DRA has no basis for making these claims.

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11 Aclara was formerly known as Hexagram.

DRA has not made a functional distinction between traditional RF based networks such as Aclara RF and RF Mesh based networks used by Silver Spring Networks. By treating the Aclara RF and Silver Spring Networks technology as fungible, PG&E indicates that DRA ignores the key differences in functionality between the two technologies, namely that an RF Mesh system does not have the same economic disadvantages as RF-based systems in rural areas, because it is not limited to moving data from a meter to a data collection unit in a single fixed path and therefore requires a less costly data collection unit infrastructure. PG&E also states that Silver Spring Networks does not have a proven and established product for gas meters and therefore it would not be advisable to use this technology for the gas meters.

5.4.2. Discussion

In its Upgrade request, PG&E is not requesting additional funds for either its electric or gas networks, and we will not authorize any such increases in this decision. We recognize that certain technologies have evolved over the course of PG&E's SmartMeter project making them more cost-effective to employ, and we expect PG&E to manage the project in a way such that the more cost-effective approaches can be merged into the deployment plans. For this reason, we will not impose conditions regarding the specific type of communications network or types of networks that PG&E should employ for its electric and gas AMI systems. We only require that whatever PG&E chooses to do, the selected network(s) must provide the necessary functions in the most reasonable cost-effective manner.

6. Cost-Benefit Analysis

6.1. Incremental Cost/Benefit Analysis

PG&E has presented its estimate of the incremental costs and benefits associated with the Upgrade as detailed in Tables 1 and 2 below. PG&E's estimate of incremental costs is $841 million (PVRR), while its estimate of incremental benefits is $1,063 million (PVRR). By PG&E's estimates, incremental benefits of the Upgrade exceed incremental costs by $222 million, and the Upgrade is thus cost effective. As discussed further on in this decision, other parties disagree with PG&E's definition of incremental costs and benefits, as well as with PG&E's quantification of costs and benefits.

Table 1
PG&E's Estimates of Incremental Costs

	Incremental Costs	
	Nominal	**PVRR**
	(Dollars in thousands)	
Deployment Costs		
Meter Devices (Less HAN and Electromechanical Meter Upgrades)	$ 310,757	$ 486,358
HAN Retrofit	32,032	29,676
Electromechanical Meter Retrofit	37,312	40,431
Information Technology	48,433	52,589
Title 24 Program Costs	-	37,906
Peak Time Rebate Costs	18,342	27,592
Project Management	15,318	17,954
Training	1,697	1,592
Risk Based Allowance	57,371	55,568
Subtotal	$ 521,262	$ 749,666
Operations and Maintenance Costs		
Operations and Maintenance	$ 5,129	$ 49,435
Risk Based Allowance	582	521
Subtotal	$ 5,711	$ 49,956

Other Costs		
Technology Assessment	$ 37,900	$ 35,285
Risk Based Allowance	7,580	6,249
Subtotal	$ 45,480	$ 41,534
Total Incremental Costs	$ 572,453	$ 841,156

Table 2
PG&E's Estimates of Incremental Benefits

	Incremental Benefits	
	Annualized	**PVRR**
	(Dollars in thousands)	
Operational Benefits		
Integrated Connect/Disconnect Switches		
Avoided Field Visits	$ (6,682)	$ (114,702)
Improved Cash Flow	(969)	(11,174)
Reduced Bad Debt	(2,429)	(26,756)
Tax Benefit from Meter Replacement	n/a	(11,799)
Subtotal	$ (10,080)	$ (164,431)
Energy Conservation/Demand Response Benefits		
Electric Conservation	n/a	$ (311,881)
Gas Conservation	n/a	(167,190)
Peak Time Rebate	n/a	(290,222)
A/C Cycling	n/a	(129,401)
Subtotal	n/a	$ (898,694)
Total Benefits	n/a	$ (1,063,125)

PG&E considers any costs and benefits related to its total AMI project (original plus Upgrade) that were not specifically included in the original AMI project cost/benefit analysis to be incremental for the purposes of justifying the cost effectiveness of the Upgrade. For instance, the PTR program will be functional with the completion of the Upgrade. The costs and benefits of the PTR program were not included in the original AMI project cost/benefit analysis. PG&E has therefore included the PTR program in the cost/benefit analysis used to justify the cost effectiveness of the Upgrade. As described above, using this definition of "incremental" and PG&E's estimates of costs and benefits results in the cost effectiveness scenario where Upgrade proposal benefits exceed costs by $222 million.

6.1.1. Positions of the Other Parties

DRA believes that Upgrade benefits that could have been achieved by the original AMI system that was approved by the Commission in D.06-07-027, should be excluded from the cost-effectiveness analysis for the Upgrade. For instance, DRA excludes PTR benefits from the Upgrade analysis because, in its opinion, PTR can be implemented with the functionalities of the meter equipment that was included in the original AMI project. DRA argues that, if benefits could have been achieved by the original system, they are not truly incremental benefits made possible with the Upgrade. Using this definition of "incremental" and DRA's estimates of costs and benefits results in a cost effectiveness scenario where Upgrade proposal costs exceed benefits by $76 million.

TURN and CCSF agree with DRA's definition of incremental. TURN also notes that, as early as May 2005, PG&E stated to the Commission (justifying its original authorization) that its proposed AMI system could accommodate, not only the rates that were identified by the Commission, but also any future dynamic tariffs that might be contemplated by the Commission over time. Thus, according to TURN, it is analytically incorrect to apply demand response benefits to this "AMI Upgrade" because (a) PG&E's original technology choice clearly is able to measure hourly data necessary for implementing a PTR and (b) PG&E has testified to the Commission that its original AMI technology had the technical flexibility to accommodate any future changes in to dynamic rates.

In response, PG&E states that "incremental costs" are costs beyond what were identified in the original project, "incremental benefits" are benefits beyond what were originally identified original and incremental costs should equal total costs, and original benefits and incremental benefits should equal total benefits. PG&E asserts that DRA's definition of incremental is unduly restrictive and unreasonable, because it eliminates any benefits that could have been achieved with PG&E's original AMI technology even though such benefits were not counted in the first case and it undervalues the benefits that will be achieved through the HAN device and IHDs.

PG&E adds that DRA's thesis is further undercut by the fact that the level of conservation and demand response benefits PG&E claims in the Upgrade could not have been achieved without the further expenditures contained in the Upgrade. While the original technology certainly created the foundation for such benefits, further expenditures for IT and the HAN were still required.

PG&E also states that DRA's position is fundamentally unfair in that DRA penalizes PG&E for being a leader in bringing advanced metering to California and implementing its SmartMeter program in two phases and DRA's approach denies PG&E the ability to count benefits that its SmartMeter Program will generate – benefits that SCE and SDG&E are able to count in their respective business cases. PG&E argues that it should not be treated differently than the other California IOUs just because PG&E's project is being deployed in two phases.

6.1.2. Discussion

Parties agree that an incremental analysis is the proper way to analyze the cost effectiveness of the Upgrade. In its application showing, PG&E justifies the Upgrade on an incremental basis, and DRA and the other parties have evaluated

PG&E's request assuming an incremental analysis, but defining "incremental" differently than PG&E, as described above.

There is much to be said for DRA's definition of incremental. Certainly if the Upgrade were cost effective under that definition, all parties would agree that it would be economically justified. However, there are factors that lead us to believe that, for the purposes of this proceeding, DRA's definition of incremental based solely on functionality is unduly restrictive.

First of all, DRA rejects all PTR benefits as estimated by PG&E under the assumption that all PTR related benefits could have been achieved through the original AMI project. DRA makes this assumption based primarily on the time differentiation function of the original AMI project. We agree with PG&E that PTR benefits are augmented by the HAN functionality. [12]

Also, PG&E correctly points out that the levels of conservation and demand response benefits PG&E claims in the Upgrade cannot be achieved without the further expenditures contained in the Upgrade. Much of the PTR program costs and associated IT costs, as contained in PG&E's Upgrade request, are essential for obtaining the conservation and demand response benefits as justified and forecast by PG&E. Those costs were not included in PG&E's original AMI case, so it is highly likely that, without these Upgrade expenditures, the benefits would not be derived to the extent estimated by PG&E, if at all. From that standpoint, PG&E's use of incremental makes some sense in that the realized benefits directly derive from the incremental Upgrade

[12] For instance, TURN indicates that PG&E could have implemented PTR without the HAN functionality, but PG&E would have to spend and additional $5.7 million per year on marketing without HAN to achieve the same awareness level target.

costs, even those benefits that might be associated with the original AMI project functionality. It might make more sense to have assigned or allocated PTR program and associated IT costs to both the original AMI project and the Upgrade. That would be a way to determine the truly incremental PTR costs associated with the Upgrade, assuming that PTR would have been provided as part of the original AMI project. We only note that such an analysis was not done.

Furthermore, DRA's definition of incremental results in PTR benefits not being recognized at all for SmartMeter program cost effectiveness purposes. For PG&E, PTR program benefits were not included in the original AMI case and, under DRA's proposal, would not be included in the Upgrade. We note that the PTR program was recognized as a benefit in the cost effectiveness analyses for both SDG&E and SCE in their AMI proceedings, and we see no reason to treat PG&E any differently. Under PG&E's definition of incremental, all appropriate AMI benefits are included in either the original AMI case or Upgrade cost effectiveness analyses.

In certain respects, DRA's definition of incremental is essentially at odds with the manner in which the Commission evaluated the AMI requests of SDG&E and SCE. Even though both SDG&E and SCE each filed only one application, an incremental analysis based on functionality could have been applied in determining the reasonableness of the requests. For example, based on what was authorized for PG&E in its original AMI application, the Commission could have analyzed SDG&E's and SCE's need for the additional functions (higher functioning solid state meters, integrated load limiting connect/disconnect switches and HAN Gateway devices) based on the specific cost effectiveness of those additional functions. In doing so, the Commission could have determined that CPP, PTR and certain aspects of electric conservation could be achieved with a basic system similar to that in PG&E's original AMI proposal and should not count as benefits to be associated with the proposed additional functionality of the HAN gateway, integrated connect/disconnect switches or advanced solid state meters. The Commission could have sought the minimal functionality, and least cost, that would be necessary to implement proposed benefits. However, the Commission did not go down that path in the case of either SDG&E or SCE. If it had, certain of the newer technologies and additional functionalities may well have been determined not to be cost effective and rejected.

Viewing costs effectiveness as we did for SDG&E and SCE and as proposed by PG&E provides for a certain amount of discretion on our part with respect to ensuring that our actions are consistent with good public policy and the overall long-term interests of the ratepayers. We support the concept of the new technologies and believe it would be inappropriate to reject them for PG&E simply because PG&E made its proposal in two phases as opposed to one phase.

For these reasons, PG&E's definition of incremental is reasonable and is in many ways consistent with the way the Commission viewed cost effectiveness for SDG&E and SCE. We will use it in our cost effectiveness analysis of the Upgrade.

6.2. Total Cost/Benefit Analysis

In its rebuttal testimony, PG&E raised the concept and issue of a total cost benefit analysis, when it evaluated the total of its original AMI case costs and benefits and its proposed Upgrade costs and benefits and compared the total results with those in the AMI cases for SDG&E and SCE.

According to PG&E, on a total basis, its SmartMeter program costs are $3.099 billion (including technology evaluation), while the most conservative benefit figure is $3.426 billion,[13] which results in benefits exceeding costs by 11%. PG&E compares this to SDG&E and SCE where a range of projected benefits resulted in benefits exceeding costs by a range of 6% to 8% for SDG&E and 0.6% to 18.6% for SCE.

6.2.1. DRA's Position

DRA opposes PG&E use of total cost/benefit comparisons, first of all, because there is insufficient information in the record to adequately compare PG&E's per meter costs with those of SCE and SDG&E. Beyond this, there is the significant question of whether applications for major capital expenditures should be evaluated on a total basis that includes the costs and benefits of a prior case. According to DRA, economists generally favor performing cost-benefit analyses on an incremental basis. The reason for this is because, even if a project can be justified on a total basis, if an incremental investment has a negative net present value, going forth with the incremental project dilutes the costs and benefits of the initial project. Economists aim to maximize the net present value, and this requires that each increment stand or fall in terms of whether it adds net present value to the overall project.

Furthermore, DRA states that looking at both AMI cases on a total basis is extremely difficult to do in the post-rebuttal stages of the proceeding, and to now

[13] PG&E states the benefit figure is conservative because it continues to use the figure of $52/kW-yr for the avoided cost of capacity for the initial portion of the project. If the figure were increased to $85/kW-yr as was done for the second portion of the project, the benefits increase to $3.598 billion. PG&E adds that if remote programmability benefits are also included, the benefits figure increases to $4.118 billion.

be asked to look at the case on a total cost and benefit basis is a violation of DRA's due process rights because an entirely different kind of analysis would have been required. DRA states that if it were to evaluate PG&E's case on a total basis, it would need to consider inefficiencies that have been produced by PG&E changing technologies and vendors after deploying more than half a million endpoints, adding that the most obvious inefficiency is the need to discard either entire endpoints or internal parts of endpoints and the additional labor costs involved in doing so. DRA concludes that if the Commission believes that this would be a preferable way to view PG&E's case, then it should reject the current application and ask PG&E to file a new case in which the analysis is presented on a total basis.

In response, with respect to DRA's argument that the costs of the other IOUs are not directly comparable, PG&E states that, even if some allowance were made for the differences, the inescapable conclusion remains that PG&E's overall costs for both phases compare favorably to SCE's and SDG&E's costs. More specifically, according to PG&E, this result further demonstrates that PG&E is managing all aspects of its project – original project, transition and Upgrade - in a reasonable manner.

With respect to DRA's argument that a total cost/benefit analysis does not include inefficiencies, PG&E states that its analysis includes all costs, including for example retrofit costs, one of the inefficiencies that DRA identifies.

6.2.2. TURN's Position

TURN asserts that the Commission should disregard any attempts to analyze the SmartMeter Upgrade project on a total cost basis, because there is insufficient data in the record to accurately engage in such an analysis. According to TURN, because costs and benefits that have been recorded so far are not on schedule with the costs authorized in D.06-07-027, in order to evaluate the Upgrade on a total project basis, PG&E would need to file the costs and benefits that have actually been recorded since the date of implementation of D.06-07-027 to today and reevaluate the total project costs going forward. TURN also asserts there are additional costs that have not been included in either the original AMI or Upgrade filings.

In response, PG&E indicates that it is true that the timing is different, but the fact remains that both costs and benefits were delayed. Further, PG&E indicates that, in spite of delays, it still intends to complete the whole project within the budget established by the Commission and to obtain the same benefits. In answer to TURN's argument that there are additional costs that will need to be added to the project cost, PG&E states that this assertion is wrong and that PG&E has included all known costs in its cost-benefit analysis.

6.2.3. Discussion

We agree with DRA and TURN that the record in this proceeding is insufficient for determining the cost effectiveness of PG&E's SmartMeter program on a total basis, especially when comparing PG&E with SDG&E and SCE. We do note though that PG&E has proposed an incremental analysis as discussed above, which is its principal justification for the Upgrade. It provides the total cost comparisons as additional justification for its request.

In concept, we do agree with PG&E that the original AMI costs and benefits plus the Upgrade costs and benefits would equal the total costs and benefits. However, it is uncertain whether all costs and inefficiencies have been included or not. Certainly the inefficiencies identified for the Upgrade would be reflected and TURN has not provided solid evidence of costs that have been omitted, but because PG&E's Upgrade proposal was not presented on a total basis, those types of issues were not necessarily analyzed in any detail. There is therefore some uncertainty as to whether all costs and inefficiencies are reflected correctly when looked at in total. For that reason, we would not use a total cost analysis as the basis for approving or rejecting the Upgrade. However, we see no reason why a total analysis cannot be used to show whether or not the cost effectiveness of PG&E's SmartMeter program is in the range or generally comparable to that of SDG&E and SCE. Our use of total analysis results will be limited to that.

6.3. Future Upgrade Cases

DRA recommends that the Commission provide clear directives to PG&E on how to present future upgrade cases. That is whether any such request should be presented on a total basis or on an incremental basis. DRA also believes there should be limitations on how frequently PG&E should be allowed to file upgrade applications.

In response, PG&E states that it has no plans for a further project upgrade. PG&E indicates that its goal was to achieve equivalent technology throughout the State. That goal will be accomplished by this decision. PG&E also indicates that the Upgrade will facilitate upgrades of both firmware and software, which means that in the future PG&E will be able to update both the functioning of the endpoint and initiate future programs without the necessity of visiting the endpoint. PG&E asserts that this aspect of the Upgrade should permit the current technology to perform capably well into the future even in the face of major advancements in technology.

With the authorization of the Upgrade and for the reasons cited by PG&E, we do not expect to see any further upgrade applications associated with the SmartMeter Program. We will not however prohibit or limit any such filings or prescribe the manner in which any such filings should be made. Future Commission actions should be guided by the circumstances that exist in the future, not on circumstances as they exist today. However, we expect that any future requests to upgrade the SmartMeter Program should be critically reviewed with the understanding that our interpretation of cost effectiveness in this proceeding is appropriate for the circumstances that exist today and may well be inappropriate for circumstances that exist in the future.

7. Costs

7.1. Meter Devices

In its application request, PG&E forecast $402,656,000 for incremental meter and equipment costs.[14] This amount covers HAN devices and load limiting switches for all customers, as well as the incremental costs associated with an advanced meter. PG&E indicates that it was, at that time, evaluating integrated meter devices proposed by a group of selected vendors and subsequently began to pursue an aggressive bidding process to obtain the best end-point technologies at the lowest possible price. In its May 14, 2008 Supplemental Testimony, PG&E indicated that it was then in the final stages of that process and had received "best and final" pricing from the remaining vendors in consideration. Due, in part, to the refined bids from these vendors, PG&E reduced its estimate for incremental costs associated with integrated

[14] PG&E forecast costs of $606.575 million reduced by the costs approved in its original AMI project for electromechanical meters, remote connect/disconnect collars and real time output devices, which amounted to $203.919 million. The costs do not include that related to the electromechanical meter upgrade which is quantified and discussed separately.

meter devices to $342,789,000.[15] As opposed to its original estimate, this amount also covers the costs of retrofitting solid state meters deployed in 2008 without a HAN device (Ubiquitous HAN or HAN Upgrade) and the cost of HAN repeater devices (HAN Connectivity). According to PG&E, this also reflects a price structure that includes the option for a substantially better warranty on the end-point technologies.[16]

There are a number of issues related to meter devices including DRA's estimate of meter device costs, the HAN retrofit, the electromechanical meter retrofit (also known as the Kern County retrofit), and HAN connectivity.

7.1.1. DRA's Position

The only party to analyze the entirety of PG&E's proposed meter and equipment costs is DRA. Since DRA is supportive of the HAN and service switch, it recommends funding costs associated with this increased functionality. DRA estimates $267.3 million in incremental meter device costs derived from its own cost estimates for advanced solid-state meters that would have the same functionality as proposed by PG&E. DRA's consultant ultimately relied on confidential bids at his disposal from seven vendors. Having signed non-

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[15] In its supplement, PG&E forecast costs of $607,819,000 reduced by the costs approved in its original AMI project for electromechanical meters, remote connect/disconnect collars and real time output devices, adjusted to reflect the estimated cost of the project decision to change from electromechanical meters to base solid state meters, which in total amounts to $265,030,000. The costs do not include that related to the electromechanical meter upgrade which is quantified and discussed separately.

[16] The costs set forth in PG&E's application included a five-year warranty on the end-point technologies, whereas the revised costs include an option to extend the warranty by an additional 15 years.

disclosure agreements to receive this information, DRA's consultant could not divulge the sources of this information or the underlying terms and conditions.

DRA notes that its consultant specifically used the lowest three bids amongst his sample set of seven, and that the average of the whole sample of seven produced a number in the same general range as PG&E's proposed cost. Knowing it could not produce enough benefits to justify PG&E's meter costs, DRA directed the consultant to use the lowest three to generate a "barebones" estimate. DRA also notes that the meters on which its consultant received quotes may have a lower level of functionality than do those that PG&E assumed in its presentation, however DRA states that it is unclear from the record what increased functionality PG&E's meters provide, or why this functionality is necessary.

From its cost estimate, DRA subtracted the funding that PG&E already received in A.05-06-028 for new or retrofitted meters. DRA also excluded all labor and network costs that were previously funded in A.05-06-028 except for labor costs associated with the Kern County retrofit. DRA included the labor costs for the Kern County retrofit because revisiting those meters would have been necessary anyway to provide the enhanced functionality.[17]

With regard to network costs, DRA's consultant states that further cost savings are available by using a single network for gas and electric meters in each geographical area. DRA was however unable to quantify these savings.

With regard to the determination of what meter costs were already approved in A.05-06-028 and should be subtracted from the cost of the advanced

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[17] The Kern County retrofit is discussed in more detail elsewhere in this decision.

solid-state meters, DRA notes that in PG&E's May 2008 supplemental testimony, it assumed funding for a basic Tier 0 solid-state meter for all customers, while A.05-06-028 had only provided funding, for the residential sector, for replacing roughly one-third of the existing electromechanical meters, and merely refurbishing the rest of those meters at a fraction of the cost of a new one. PG&E's supplemental testimony includes a $61.1 million adjustment to its baseline costs for end-point technologies to reflect the estimated cost of the project decision to change totally from electromechanical to base solid state meters.[18] DRA states it did not adequately understand this evolution in PG&E's thinking, and its consultant merely followed what had been authorized in A.05-06-028, which provided funding to replace only one-third of the existing electromechanical meters rather than providing solid-state meters to everyone. DRA believes it would be appropriate to modify its figures to put them on a comparable basis with PG&E's revised numbers, suggesting in errata that PG&E's $61.1 million reduction be used as a proxy for the effects of putting its numbers on a comparable basis.

DRA stresses that the $61.1 million is only a proxy of this reduction, and that a larger reduction can be achieved by directly substituting a blended cost for a Tier 0 basic solid-state meter, for the cost of new and retrofit electromechanical meters in its Table 2-1. According to DRA, doing this would more than compensate for other errors that PG&E alleges. However DRA indicates that it will refrain from further changing its estimates because there are compensating changes that could be made in both directions.

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[18] Estimated incremental Upgrade costs were reduced by the $61.1 million amount.

In response, PG&E states that DRA's original analysis is riddled with errors, which required DRA to make a number of corrections, one of which totaled nearly $200 million. Several additional errors were corrected in errata. PG&E indicates that it pointed out other errors to DRA that went uncorrected, including one that shorted PG&E about $10.5 million.

PG&E states that most importantly, after it pointed out DRA's errors, DRA changed its approach for this cost category and based its new recommendation on confidential pricing data from third parties that were never disclosed to PG&E. According to PG&E, DRA's unwillingness to disclose this third-party data -- on which it based its analysis -- deprived PG&E of its due process rights to examine such data and compare it to the data provided by PG&E.[19] PG&E quotes the following from DRA:

> …If you are asking me should PG&E know the other terms in order to effectively evaluate whether the product they are proposing to purchase is more cost-effective from their perspective than the alternatives I've proposed? I would say, yes, they need more information… .[20]

For the above reasons, PG&E argues that DRA's cost testimony should be given no weight.

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19 Because of PG&E's concerns over the process followed by DRA, PG&E filed a motion to strike DRA's meter and equipment cost analysis. The motion was denied. However, in his oral ruling, the administrative law judge conceded the difficulty of relying on the evidence provided by DRA and indicated that any use of this information by the Commission in this proceeding will take into consideration the possible ramifications of the confidentiality restrictions, and the evidence would be weighed accordingly. *See* 5 RT 612-613.

20 DRA, Levesque, 4 RT 553.

7.1.2. Discussion

DRA's recommended incremental cost for meter devices (the meter, disconnect switch, HAN gateway device and AMI module) is approximately $206 million, while PG&E's proposed amount is approximately $310 million.[21] DRA's total cost estimate is approximately $471 million as opposed to PG&E's estimate of $575 million. With the evidence before us, we have little choice but to adopt PG&E's estimates of meter device costs. It is unfortunate that non-disclosure barriers prevents any detailed analysis of DRA's recommendation, but without some idea of what the differences are and whether those differences appropriately consider PG&E's situation and needs, we cannot adopt costs that are so different from that proposed by PG&E.

PG&E's estimate is based on costs derived from an RFP process. Based on responses to that process, PG&E conducted an evaluation of the integrated meter devices from certain vendors to help identify vendor and meter device technologies best suited to serve PG&E and its customers. According to PG&E, the vendors selected for further consideration were selected following a rigorous vendor selection process in order to ensure that the vendor ultimately selected has sufficient resources, credibility, and expertise to supply the necessary equipment and services to complete their work within an appropriate timeframe and budget. For a project of this magnitude such evaluation is prudent.

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21 The number for DRA incorporates PG&E's $61.1 million adjustment to baseline costs that was reflected in its May 2008 supplemental testimony. The total baseline costs for end-point technologies from PG&E's original AMI decision is approximately $265 million. For comparison purposes, PG&E's number does not include HAN connectivity costs or HAN Upgrade costs other than the HAN gateway device itself and does include new meter devices associated with the Kern County electromechanical meter upgrade.

However such evaluation cannot be performed with respect to the vendors and devices related to DRA's projected costs, due to the non-disclosure restrictions.

DRA's data, which according to DRA shows the average of the bids considered by its consultant as being in the same general range as PG&E's proposed cost, provides some additional assurance that PG&E's RFP approach is reasonable.

It would be inappropriate to impose DRA's proposed costs on PG&E without assurance that the related meter devices provide the necessary functions, without assurance that the vendors are capable of providing the equipment when needed, and without knowledge of the type of warranties that are associated with the costs.

For these reasons, we adopt PG&E's estimate of the incremental costs for meter devices. However, we will require that PG&E provide quarterly reports on the implementation progress of the Upgrade to the Commission's Energy Division and any interested parties. PG&E should consult with the Energy to determine what information PG&E should provide.

7.2. HAN Retrofit

As described in PG&E's testimony, the HAN retrofit[22] involves PG&E deploying 288,000 upgraded meters with load limiting switches and upgrading these meters with HAN gateway devices at a later date. PG&E stated that one of the key principles guiding the company during its transition from electromechanical meters under the existing SmartMeter Program to the upgraded meters proposed in this proceeding was the objective of beginning

[22] The HAN retrofit is also referred to as ubiquitous HAN.

deployment of solid state meters, preferably with load limiting switches and HAN devices, at the earliest strategic point in its deployment schedule. In its May 2008 supplemental testimony, PG&E indicated that it had recently learned that its preferred HAN devices were scheduled to become commercially available in the fourth quarter of 2008. Therefore, PG&E planned to install solid state meters that have a load limiting switch -- but that do not have a HAN device -- during the limited period between the time that PG&E completes the installation of the remaining electromechanical meters (e.g., summer 2008) and the time the HAN devices become available. To support real-time pricing, dynamic pricing, and opt-out programs for all customers, PG&E stated it will be necessary for PG&E to then retrofit these above-described solid state meters with HAN devices. PG&E estimated the net cost increase of such a retrofit will be approximately $30 million.

In support of its decision to proceed with the HAN Upgrade, PG&E's consultant, Lechner, performed an analysis of several meter deployment scenarios comparing lost benefits to reduced costs, if PG&E had suspended meter deployment until HAN devices became available. According to PG&E, the analysis indicates that lost benefits exceed reduced costs, and PG&E acted reasonably in moving forward with meter deployment without the HAN devices.

7.2.1. DRA's Position

DRA excludes all costs associated with the HAN retrofit except those directly associated with enhanced functionality. DRA believes that PG&E could have merely suspended the deployment of solid state meters without a HAN device and avoided the additional costs that PG&E includes. DRA also criticizes PG&E's suspension analysis, stating that the cost-benefit analysis is distorted by three problems: (1) it ignores the present value cost savings of delaying the deployment of the subsequent five million meters; (2) it artificially truncates the stream of foregone benefits for all scenarios to 2011; and (3) it includes different numbers of months of foregone benefits for the four scenarios evaluated.

Regarding the first problem, DRA asserts that Lechner ignored the cost savings from delaying the deployment of some five million meters apparently because he did not find them to be important enough to include. According to DRA, the particular studies that led him to this conclusion are not in the record, but, because of this decision, the only endpoint costs Lechner includes in his analysis are those associated with the 288,000 meters, which he then compares with the foregone benefits associated with over five million meters. DRA states that the result is predictable – the benefits dominate the analysis.

The second problem, according to DRA, is that Lechner truncated the period of analysis such that it would end in 2011, in spite of the fact that the benefits persists for the projected 20-year life of the endpoints for all four scenarios he considered. DRA asserts that had Lechner not truncated the benefits streams, the benefits in nominal terms for each of the four scenarios would have been identical. The only difference would have been in the timing of the benefits.

DRA's third problem has to do with Lechner truncating the benefits of all scenarios to the end of 2011, which resulted in a five fewer months being used to calculate the benefits for the five-month scenario relative to the non-suspension scenario. According to DRA, had he allowed the benefits streams to continue for the lifetime of the equipment, the benefit streams for all the scenarios would have included the same number of months. The only difference would be the point in time when they would have occurred.

In response, regarding DRA's allegation that Lechner's analysis ignores the present value cost savings of delaying the deployment of the subsequent five million meters, PG&E states that Lechner specifically considered the cost implications of suspending five million meters and the analytical result was the basis for his conclusion, and cites the following cross-examination:[23]

> DRA Counsel: Mr. Lechner, in your analysis did you include or consider the impact of delaying the cost of deploying 5 million meters?
>
> PG&E witness Lechner: During the course of my analysis and analyzing the implications of the cost, I considered that, whether that would have an impact on the end result.
>
> Q: What was your conclusion?
>
> A: The conclusion is … as I refined the model on the cost side by contemplating the time value of money under various different delay scenarios, in conjunction with additional escalation, in conjunction with additional inefficiency costs, in conjunction with the additional costs that would be incurred, each scenario that I looked at had no implications, no impact on the overall result, I drew the conclusion that the cost side of this model really isn't driving the equation. It's the benefits side.

Thus, PG&E asserts that, counter to DRA's allegation that Lechner ignored the cost savings from delaying the deployment of some five million meters apparently because he did not find them to be important enough to include, the record shows that Lechner specifically considered the cost implications of suspending five million meters and the analytical result was the basis for his

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[23] 2 RT 271.

conclusion. PG&E emphasizes that the only cost "savings" from a suspension scenario are related to the time value of money associated with deferral, and notes that Lechner specifically considered these "savings," but, unlike DRA, Lechner also considered the significant additional costs associated with suspending endpoint deployment.

PG&E states that DRA's second allegation -- that Lechner's analysis "artificially truncates the stream of foregone benefits for all scenarios to 2011" and that this "inflates" the differential between the lost benefits between PG&E's business case and a suspension scenario -- is wrong both in theory and application, with the following explanation:[24]

> From a theory standpoint, Mr. Lechner properly pointed out during cross examination that in doing a comparative analysis between a continued vs. suspended deployment scenario, it is necessary to compare the same period of time. By comparing the stream of benefits generated by continuing deployment with the stream of benefits generated by a suspended deployment over a defined period of time, Mr. Lechner was able to determine the present value of "lost benefits" caused by a delay scenario. As Mr. Lechner also pointed out during cross-examination, extending the period of time to evaluate lost benefits caused by a suspension scenario does not change the fact that benefits accrue at a faster rate under the continued deployment scenario than they do under a suspension scenario.
>
> From an application standpoint, DRA erroneously attempts to link the benefits associated with meter deployment to the estimated 20-year life of the endpoints and fails to consider the compounding nature of benefits over time. The estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic

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[24] *See* PG&E Opening Brief, pp. 21-22.

> impact of a deployment suspension scenario. Benefits begin to accrue when an endpoint is installed and activated. A large percentage of the operational benefits created by this endpoint activation are due to PG&E's ability to avoid the labor costs of meter readers on activated SmartMeter routes. When an endpoint reaches the end of its useful life, the meter will be repaired or replaced and the benefit stream will continue, uninterrupted (e.g., PG&E will not re-hire its meter readers at the end of the estimated life of a SmartMeter). This is another reason why it is essential to use the same end date for all scenarios in a comparative analysis of benefit streams.

Regarding DRA's third allegation that Lechner's benefits differential is inflated because he used "five fewer months" to calculate the benefits for the five month suspension scenario than for the non-suspension scenario, PG&E states that DRA misses the point of the comparative analysis. It is the timing of endpoint deployment that drives the magnitude of realized benefits, and suspending deployment of endpoints would delay the realization of benefits that would be obtained under a non-suspension scenario. PG&E states that Lechner's analysis properly modeled the stream of benefits associated with PG&E's endpoint deployment plan without a suspension scenario and compared this to the stream of benefits that would result from suspended deployment plans, and comparing the present value of these various benefits streams provides a clear quantification of the impact of suspension benefits realization.

7.2.2. TURN's Position

It is TURN's position that PG&E could avoid this increased cost if it simply waits to deploy its solid state meters until (a) its preferred HAN technology is commercially available or (b) a final Commission decision on this application. TURN states that PG&E has chosen to prematurely move ahead with a large number of solid state meters by the end of 2008, even though PG&E intends to scrap or retrofit all of the meters later, requiring at a minimum, a duplicative expensive field visit from a PG&E employee or contractor, and argues that the ratepayers should not be saddled with the cost of PG&E's unreasonable management strategies.

TURN states PG&E' suspension analyses are flawed for many reasons and should be disregarded. First, the analysis was not completed before this application was filed in December 2007, so TURN states it could not have been used to justify the project management decisions. Second, TURN asserts analytical flaws render the analysis useless. According to TURN, a correct analysis would have taken all recorded costs and benefits up to July 2008 and then analyzed a delay (recognizing all recorded costs and benefits) compared to an updated forecast of remaining costs and benefits, something PG&E did not do. In addition, TURN criticizes PG&E's assumption that all meters are activated and providing O&M and demand response benefits in the same month they are installed. TURN notes that PG&E currently has over 534,000 gas meters installed but only 67,000 activated, and there are no demand response benefits currently and PG&E has been installing meters for at least a year and a half.

CCSF states that it agrees with TURN's reasoning for rejecting the HAN retrofit and TURN's position that ratepayers should not have to pay the additional $34.8 million (with risk allowance) requested by PG&E.

In response to TURN, PG&E states that TURN's suggestion that Lechner's analysis should be rejected because it was performed after PG&E's initial Upgrade filing, ignores the record, noting that PG&E witnesses Corey and Meadows both testified that PG&E had considered the potential costs and benefits of delaying deployment while PG&E evaluated the emerging technology. When PG&E submitted its Application in December 2007, it was in the middle of negotiations with its Upgrade vendors and was continuing to refine its specific technology selections and deployment alternatives. According to PG&E, this was an appropriate time to analyze the detailed implications of various deployment scenarios, including potential suspension of endpoint deployment depending on the availability of PG&E's preferred HAN device identified as a result of the ongoing vendor bidding. PG&E further states that its May 2008 update to its Upgrade Application included the results of its ongoing vendor negotiations and that, had the results of Lechner's analysis been different and concluded a suspension scenario was indeed preferable to continuing deployment, PG&E would have included such a result in its May update.

PG&E states TURN's suggestion that "[a] correct analysis would have taken all recorded costs and benefits up to July 2008 and then analyzed a delay … compared to an updated forecast of remaining costs and benefits" ignores the fact that the costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the comparative analysis because they are exactly the same for all scenarios being compared.

With respect to TURN's argument that Lechner's assumption regarding the timing of benefits relative to endpoint installation is wrong, PG&E states that the identification of benefits with endpoints in the month they are installed was a simplifying assumption applied to each scenario. While this does not calculate the precise timing of benefits realization, it is an appropriate approach to compare the benefit stream of a continued deployment scenario with various suspension scenarios, provided the assumption is consistent among the scenarios, which according to PG&E, it was.

7.2.3. Discussion

PG&E's suspension analysis of the HAN Upgrade appears reasonable. Its consultant compared lost benefits due to suspension to reduction in project costs resulting from the suspension relative to the base case. Relative to the base case, the only cost that would not be reduced due to a suspension is the cost of the HAN gateway device. All of the other costs are associated with the retrofit of the meter. PG&E's consultant added the cost of the HAN device to the suspension costs[25] to quantify the total costs that should be subtracted from the reduced costs due to the suspension before being compared, on a PVRR basis, to the lost benefits due to the suspension. In all three suspension scenarios (three, four and five-month suspensions), the analyses showed the lost benefits exceeding the net reduced costs.

We have evaluated the criticisms made by TURN and DRA with respect to PG&E's consultant's suspension analyses along with PG&E's responses. In general, we find that PG&E has adequately explained and defended the analyses, and we are comfortable in using the analyses as a basis for determining the reasonableness of PG&E's actions.

In particular, we agree that the estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic impact of a deployment scenario. If deployment is suspended for five months, benefits for those five months are lost. At any point in time beyond 2011, when the base and

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[25] Suspension costs include the monthly suspension costs that PG&E is contractually obligated to pay for suspending the installation contract, the monthly costs for suspending PG&E project management office operations, and the labor escalation costs PG&E would incur by installing the meters with HAN devices months later than originally planned.

suspension scenario are compared, the five-month suspension scenario will have five months fewer benefits. That is simply because the benefits go on indefinitely and do not end when the meter has been in place for 20 years and is retired and replaced or is refurbished.[26] We also agree that the costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the comparative analysis because they would be the same for all scenarios being compared.

Lechner's conclusion that the cost of the 5 million meters had no impact on the overall results in his analysis was based on his examination of his model outputs and appears reasonable. DRA had access to Lechner's model and has not indicated that the outputs that Lechner relied on are erroneous in any way.

Also, PG&E has provided sufficient explanation as to why its consultant's suspension analysis was performed after the filing of the application. What is important is that it was performed before this aspect of meter deployment began, and was thus available for PG&E's project management to use in determining whether or not to go forward.

While PG&E's decision to proceed with the HAN retrofit appears to be reasonable, the magnitude of the retrofit cost estimate ($32,026,000 plus a 10% risk based allowance) has not been fully supported and justified. There is little support for PG&E's quantification of the number of meters that would necessarily be installed without a HAN device. Also, the record does not include detail and substantiation of all of the various cost components of the retrofit. For

[26] While any future AMI system may differ from the upgraded SmartMeter Program, the current benefits of the SmartMeter Program will likely be obtainable through any future new systems and will continue.

instance, while the costs include that necessary to physically retrofit a meter with a HAN device, there is no detail as to what that particular cost is, what it was based on, and why it is reasonable. Also, it is not clear whether the communication module that is replaced has any salvage value and if so whether that was factored into the costs. To account for uncertainties and attempt to ensure that ratepayers only fund appropriate costs, we will reduce adopted funding for the HAN retrofit by $5,500,000 (plus $550,000 for the related risk based allowance).

7.3. Electromechanical Meter Retrofit

At the time of the application filing, PG&E had already procured 230,000 electromechanical meters intended for its Kern County region. Approximately 123,000 of these meters had already been installed and the rest were to be installed by mid-2008. Considering the availability of the improved meter devices and the continued ability to achieve the benefits of SmartMeter Program deployment, PG&E believed it would be reasonable to make the transition from electromechanical meters to solid state meters as early as practicable to minimize the potential retrofit of installed electromechanical meters with upgraded meter devices pending the Commission's approval of PG&E's request in this application. PG&E decide the time to make the transition was after completing deployment of the Kern region.

Once all customers have received an advanced meter (i.e., in 2011), PG&E proposes to upgrade the estimated 230,000 electromechanical meters with the new solid state meters so that all of PG&E's electric customers can participate in the new service offerings and increased functionality available with the upgraded meters. PG&E estimates that it will require approximately six months to upgrade these electromechanical meters installed prior to the SmartMeter

Program Upgrade. PG&E has forecast $37,312,000 in costs relating to the retrofit of meters deployed in the Kern region. These costs would provide labor and material sufficient to replace the 230,000 meters deployed in the Kern region without a HAN device or load limiting switch, with a complete advanced solid state meter, integrated load limiting switch and a HAN device.

7.3.1. Positions of DRA and TURN

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

DRA's argument for disallowing most of the Kern County retrofit costs is not based on the idea that the Kern County deployment could have been delayed, it is based rather on DRA's belief that PG&E came to the Commission prematurely with its original application, A.05-06-028, in the first place. DRA states that its support for that application must be qualified, in that such support was based on representations that PG&E made that have turned out to be wrong. Transcript evidence shows that DRA witness Abbott had expressed concerns to PG&E at a meeting in December 2005 about whether the DCSI system would have sufficient bandwidth to handle the signals in an urban area with high density. He was assured by PG&E that it had developed workarounds to this problem. Therefore, he gave PG&E the benefit of the doubt, and in his testimony in A.05-06-028, stated that PG&E's technology choice is "generally reasonable." According to DRA, representations also had been made by PG&E about the ability of the DCSI technology to support the HAN technology, and these did not pan out either. It is because of PG&E's decision to "jump the gun" that DRA does not even include the cost of the base meter in the Kern retrofit.

TURN recommends that the Commission disallow all the costs related to the electromechanical meters in the Kern region by (1) disallowing the $41.03 million requested in this application[27] to retrofit the installed electromechanical meters; and (2) removing $23.2 million from PG&E's original AMI budget, thus making it less possible for PG&E to indirectly recover some of these costs through contingency allowances. TURN recommends the removal of the meter costs from the original AMI budget, because they were stranded by poor management decisions regardless of the outcome of this Upgrade application.

TURN states that despite the fact that PG&E filed a request for authorization of over a half a billion dollars to "upgrade" its AMI project, it persisted in installing meters in the Kern region that it knew it would strand in only four years. While PG&E claims that it did not finally decide it would change its AMI technology until the date that it filed this application in December of 2007,[28] TURN argues that PG&E indicated that it began the process of evaluating solid state meters, integrated load limiting disconnect switches,

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[27] This number includes the risk based allowance associated with the electromechanical meter retrofit.

[28] Exhibit 208, p. 12.

and the availability of home area network technologies in early 2007,[29] and, by May 2007, PG&E indicated that it was interested enough in the new technologies to adjust its meter procurement plan and tell its electromechanical meter supplier that it intended on terminating the contract for buying electromechanical meters.[30] According to TURN, PG&E was not forced to strand this investment. It proactively chose to do so and did so while requesting additional funds to fully deploy an entirely different technology. In TURN's opinion, PG&E's decision to continue installation of electromechanical meters in the Kern region was unreasonable and imprudent, and the Commission should not insulate PG&E from the consequences of its decisions.

In response, PG&E expressed its understanding that DRA would allow about $18.8 million of the requested costs, by adding $6.3 million in labor costs to about $12.5 million for the incremental costs of an advanced solid state meter, the integrated load limiting switch and the HAN device.[31] DRA would not allow funding for the "base" cost of the meter itself or the communications module that would need to be replaced. PG&E further understands that TURN estimates the

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[29] Exhibit 209, Attachment G.

[30] *Id*.

[31] According to PG&E's opening brief, the costs of the Electromechanical Meter Upgrade of approximately $37.3 million (confidential Workpapers Supporting Exhibit 7, WP A-2, line 7) includes approximately $12.5 million of incremental equipment costs. This includes $4.8 million of incremental costs associated with advanced endpoint functionality (230,000 x ($58 - $37)), approximately $5.2 million of costs associated with the integrated load limiting switch (230,000 x $23), and approximately $2.5 million of costs associated with the HAN Gateway Device (230,000 x $11), for the endpoints located in PG&E's Kern Division (Confidential Workpapers Supporting Exhibit (PG&E-7), WP 1-50).

installation costs of the Kern deployment for its proposed disallowance of $23.2 million.

It appears to PG&E that, despite the proposed disallowances, both DRA and TURN want the retrofit to be performed. According to PG&E, what intervenors debate -- and the issue on which their proposed disallowances depends --is whether PG&E should have installed (in the first instance) the DCSI power line carrier (PLC) equipment on electromechanical meters in Kern. For the three reasons described below, PG&E asserts that it was right to do so.

First, PG&E indicates that its deployment of the electromechanical meters in Kern followed the directives of D.06-07-027 to the letter and was strongly supported by DRA in that case. PG&E points out that (1) the meters deployed include the technologies approved in D.06-07-027, (2) no party has alleged that PG&E has somehow strayed from the letter or intent of D.06-07-027 in deploying these meters, and (3) the deployment has been successful and the meters are working as intended, generating operational benefits as meters are activated.

Second, PG&E states that the argument that PG&E should have delayed installing the Kern meters, as an alternative to incurring the proposed retrofit costs has no merit, because it ignores the evidence in the record that continued deployment was beneficial for ratepayers. PG&E explains that when it became apparent the Upgrade technology might be becoming commercially feasible, PG&E considered a short-term suspension of electric meter deployment, but determined this would not be in the best interest of its customers. PG&E concluded that delaying implementation would serve to increase overall costs as vendor commitments had already been made and a suspension would result in further delays to the benefits.

Third, regarding DRA and TURN suggestions that if PG&E had installed solid state meters in Kern, then a retrofit to accommodate the HAN device would not be necessary,[32] PG&E states that a retrofit would still be necessary and the original deployment would have been more costly. This is because the use of electromechanical meters in the original deployment plan resulted in approximately $36 million in cost savings when compared to using basic solid state meters. PG&E also states that these basic solid state meters that were available for deployment at the time of the original AMI case would not support a HAN device and thus would need to be replaced now anyway, a point that DRA conceded during hearings.[33]

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[32] PG&E cites DRA, Exhibit 108, Exhibit 2, Chapter 3, p. 3-3, line 11 and TURN, Exhibit 208, pp. 12-13 as the basis of the suggestions.

[33] DRA, Abbott, 4 RT 463.

7.3.2. Discussion

Electromechanical meters have been deployed in the Kern region, and, as a result of PG&E's Upgrade request, the electromechanical meter costs will become stranded once these meters have been replaced. We see the fundamental issue to be whether these stranded costs should be addressed as part of the costs of the original AMI program or as part of the costs of the Upgrade. As discussed further in this decision,[34] we determine that the stranded costs related to the electromechanical meters should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project. Therefore, for purposes of this proceeding, we need not determine whether PG&E should or should not have deployed electromechanical meters in the Kern region, or whether PG&E came prematurely to the Commission with its original AMI application.

Our result is similar to that of DRA in that we include costs for the upgraded system, but exclude costs related to the original meter and communications device. Based on PG&E's representation of DRA's recommended cost for the electromechanical meter retrofit, we will adopt, as reasonable, an amount of $18.8 million for that purpose.

Because of the manner in which this issue is resolved, it would not be appropriate to remove $23.2 million from the original AMI budget as proposed by TURN. It appears that amount represents the stranded costs that should be absorbed through the risk based allowance or contingency.

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[34] *See* Section 7.12.2.

7.4. HAN Connectivity

PG&E states that one challenge in effectively deploying HAN technologies is the variety in configuration of customers' premises. In some residences, the signal from the HAN device may need to travel long distances because of a meter located away from the home. Even for homes with attached meters, it is possible that appliances and devices such as thermostats, pool pumps or water heaters may be placed in locations that are difficult for the signal to reach. For example, water heaters may be located in basements or garages and pool pumps could be in external structures.

According to PG&E, currently, there are two predominate HAN gateway technologies in the marketplace, PLC technology and RF technology. Each of these technologies has strengths and weaknesses in dealing with the challenges created by the diversity of structure types and distances. For example, PLC technology is better at traveling long distances and has the ability to communicate with some devices that are not plugged into an electrical outlet such as a thermostat, while RF technology is better able to reach devices that may not be able to receive PLC communications.

To compensate for the variations in functionality of different HAN gateway technologies and to take advantage of the best available solutions, PG&E proposes a combined RF and PLC solution. This combination of approaches will serve more types of homes than one approach or the other. PG&E would likely deploy a PLC-based solution to customers living in multi-dwelling units. This is because the HAN signal travels into the home through the electric wiring instead of via radio signal that can frequently be blocked or attenuated. Therefore, for the HAN gateway, PG&E proposes to use a combination of Homeplug (PLC) and Zigbee (RF) devices – whereby the PLC solution would be used to enhance reliable connectivity for large, multi-storied and multi-unit dwellings, and the RF solution would likely be deployed to other types of residential electric customers.

Based on ongoing research and discussions with DRA, PG&E believes that it is prudent to deliver a standardized and common RF based HAN signal into all customers' premises.[35] According to PG&E, this means that for the approximately 40% of premises that were expected to receive a Homeplug device, all of those premises will require some type of bridging or augmentation device to bring an effective signal from the meter location to an interior wall of the customer's premises.

However, at the present time, there are still a number of uncertainties regarding the best approach to extend the connectivity of the HAN devices at the meter to an interior wall of a customer's premise. PG&E states that, although much work in the industry and in standards development is occurring, there is not yet a standard approach to reliably deliver HAN connectivity on a universal basis, including translation or bridging devices. PG&E and the others in the industry are currently evaluating several approaches to address this challenge. Therefore, while it is premature to settle on a specific solution and lock in to a defined approach for an extended period of time, PG&E believes its recommendation is appropriate given the stated goals related to the home area network and reflects a thoughtful consideration of the known technical

[35] For example, regardless of what technical solution PG&E uses for a particular HAN device in the meter (RF or power-line based), the customer would be provided a single or common RF based protocol once the signal is made available within the customer's premises.

challenges of each HAN technology and the state and direction of the HAN standards and industry.

PG&E has developed its estimate of costs to extend HAN functionality from the electric meter location to an interior wall of a customer's premises using the following assumptions:

(a) 40% of customers' premises with installed Smart Meters will require a bridging, translation or another augmentation device to bring RF connectivity to an interior wall of the customer's premises.

(b) During the period covered by the revenue requirement request in this case, 15% of the above-described customers' premises will require a bridging, translation or another augmentation device to bring RF connectivity to an interior wall of the customer's premises during the project period, considering customers' demand for HAN functionality. The remaining customers would obtain the bridging, translation or another augmentation device in later years.

(c) PG&E set an allowance of $50 for each bridging, translation or other augmentation device for either the provision of such a device or to provide a rebate to customers seeking to install their own devices.

By doing the above, PG&E states that it would deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises. However PG&E cautions that no utility can guarantee that the HAN signal would be available throughout all areas of the customer's premises or property. Under PG&E's proposal, additional signal enhancements within a customer's premises to extend the connectivity of the HAN device from an interior wall to other locations within the premises would be the responsibility of the customer or the provider of the HAN enabled device with which the customer desires to establish a connection.

For HAN connectivity, PG&E seeks $16,891,000 in incremental costs. In total, the HAN connectivity related PVRR amounts to $59,123,000 under PG&E's proposal.

7.4.1. DRA's Position

DRA recommends Homeplug deployment be set at 30% rather than the 40% requested by PG&E. According to DRA, while PG&E's Homeplug estimate is based on the "nature of dwelling types in its service area," that is, the ratio of single family homes to multiple family homes, it does not take into account that some multiple family homes are duplexes that are not much larger than a single family home. DRA states that PG&E has provided no data on the typical broadcast footprint (in feet of dispersion) of the Zigbee interface, and PG&E has adopted the most conservative assumption possible, that is, that all multiple family homes will require a HomePlug interface. DRA likens this to asking for an extra cushion on top of its normal risk allowance.

In response, PG&E states that the net effect of DRA's recommendation would be to reduce PG&E's costs by approximately $4 million[36] and argues that DRA's recommendation is not supported by any analysis or documentation and is made solely as a way of reducing project costs. PG&E cites the following from the evidentiary hearing transcript:[37]

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[36] By changing the percentage split of ZigBee/HomePlug from 60%/40% to 70%/30%, the weighted average cost of the HAN Gateway Devices would be reduced by $0.75 and result in a decrease of approximately $4 million.

[37] Reporter's Transcript, p. 548, line 13 to p. 549, line 9.

PG&E Counsel: What does DRA want to do?

DRA Witness Levesque: 70/30. [Meaning 70% ZigBee and 30% HomePlug.]

Q: Did you do any analysis of PG&E's system to come up with that percentage?

A: The foundation for that change was in one sentence of what if it were 70/30. And the reliance upon would 70/30 make sense was based entirely on subjective opinion of number of households, number of apartments and small apartment buildings the size of a population of the City of San Francisco. And that was in a communication with DRA that gave me that information.

I have no supporting, specific documentation for the 70/30. And I don't know if there is empirical evidence in the marketplace today as to whether HAN will produce 62/38 or 70/30.

Q: When you say what-if scenario, was that an effort to get the price down?

A: It was an effort to understand the magnitude of what a change would be of -- if HAN were 10% more effective, what that might do for pricing.

Q: The effect of raising the percentage of [ZigBee] effectively reduces the amount of money PG&E gets; right?

A: That is correct.

Accordingly, PG&E asserts that DRA's recommendation has no proper evidentiary basis, PG&E's proposal for a 60/40 split in the deployment of ZigBee and HomePlug devices is the only proposal on record with a proper evidentiary basis, and PG&E's proposal is the most appropriate for promoting HAN receptivity for customers.

7.4.2. TURN's Position

TURN argues that the request should be rejected, because extended HAN connectivity costs are directly related to PCTs associated with PG&E's Title 24 program, and PCTs will not be incorporated into the next round of Title 24 building standards. PG&E will not be recruiting customers until 2013, outside the forecast period for this application. Therefore, TURN asserts that HAN connectivity costs should also be excluded from the program.

TURN also argues that HAN bridging device technology is not well known at this time, and is in the infant stage of development. According to TURN, the Commission should therefore not authorize this request and expose ratepayers to further risk of stranded technology and costs. TURN also questions the efficacy of this type of investment given that customers in multi-family dwellings are the least likely customers to be able to take advantage of HAN to alter energy usage since they rarely have the ability to install HAN-enabled appliances. Furthermore, because these customers generally have a lower energy usage than residential customers that live in single-family dwellings, TURN asserts they have less energy to conserve, reduce, or shift and are therefore poor candidates for providing demand response.

In response to TURN, PG&E states that regardless of whether a landlord or tenant owns an appliance, the person who pays the energy bill – typically the tenant – has the incentive to reduce his or her energy costs through the information available from the HAN repeater device. According to PG&E, studies have shown that tenants may have even more to gain from the information available from the HAN. This is because such tenants are deprived of the ability to control their energy use through hardware choices and their best means of control is through their use patterns and the information available through the HAN.

7.4.3. Discussion

First of all, we are in agreement with PG&E's general direction in attempting to deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises. To do this, it is reasonable to use both RF and PLC technologies as proposed by PG&E.

With regard to whether the HomePlug or PLC technology should be applied to 30% of the residences as proposed by DRA or 40% as proposed by PG&E, we will adopt PG&E's 40% proposal. The basis for DRA's proposal stems from a hypothetical analysis involving cost sensitivity based on a 30% assumption. There is no evidence as to the reasonableness of using 30% to reflect what might actually occur.

With respect to TURN's argument that HAN connectivity costs should be excluded because PG&E will not be recruiting Title 24 PCT customers until 2013, we decline to do so, because HAN connectivity relates to not only PCTs but also to other devices such as in home displays. In PG&E's supplemental testimony, the proposal for HAN connectivity was expanded to all customers, not just to Title 24 PCT customers.[38]

Regarding TURN's argument that customers in multi-family dwellings are the least likely customers to be able to take advantage of HAN to alter energy usage and PG&E's response, the determination of who will use the HAN

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[38] *See* Exhibit 7, p. 8.

technology, and to what extent they will use it, is fairly subjective at this point. From a policy perspective, we feel it is important that customers that wish to use the technology are, to the most reasonable extent possible, able to do so.

We are however somewhat hesitant to authorize additional funds to provide a single or common RF based protocol once the signal is made available within the customer's premises. As PG&E itself acknowledges there is not yet a standard approach to reliably deliver HAN connectivity on a universal basis, including translation or bridging devices. TURN argues ratepayers should not be exposed to the risk of stranded technology and costs, and PG&E's request regarding HAN connectivity should be rejected. On the other hand, we believe HAN connectivity on a universal basis makes sense for such purposes as advancing and developing the HAN technology in an efficient manner. With the expectation that it may be necessary in some form, we will authorize PG&E's HAN connectivity request. We expect PG&E to adapt the implementation of HAN connectivity over time consistent with approaches and solutions that are being addressed and developed, currently and in the future, by those in the industry that are addressing these issues. It is PG&E's responsibility to achieve HAN connectivity in the most cost effective manner within the costs and risk based allowances provided by this decision. PG&E should understand that we will be extremely reluctant to saddle ratepayers with stranded assets and costs associated with any cost overruns related to HAN connectivity.

7.5. Information Technology

PG&E estimates that it will incur incremental information technology (IT) costs resulting from the additional scope functionality of the SmartMeter Program Upgrade. These include IT costs to support the PTR Program, HAN functionality, the AC Program, the Load Limiting Functionality and IT project management. Briefly,

- In order to accommodate its proposed PTR program, PG&E states that it will be necessary to modify its Customer Care and Billing (CC&B) and Customer Service On-Line (CSOL) systems. To estimate the cost of these efforts, PG&E used its standard four-phase IT model: pre-build, develop, test, and support. The estimated labor cost of this incremental scope increase is $4 million, which is based on PG&E's average, daily, internal and external labor rate of $1,200. PG&E expects to incur these PTR-related costs from mid-2008 to mid-2009.

- To support the HAN functionality, PG&E proposes to establish reliable and secure two-way communication between PG&E's network management systems and the HAN gateway devices. It will also confirm the ability to address an Internet Protocol (IP) addressable device behind the meter and receive a response. PG&E anticipates it will perform the HAN infrastructure and integration work in 2009 at an estimated cost of $23.1 million, which includes $4.6 million of non-labor costs and $18.5 million of labor costs.

- Starting in 2013, PG&E proposes to use HAN capability to provide AC Program functionality for Title 24 compliant programmable communicating thermostats (PCT) as part of the SmartMeter Program Upgrade, in order to enhance and expand PG&E's current SmartAC Program. PG&E states that operating the AC Program on the HAN network (likely in parallel to the current vendor-provided SmartAC Program) for all Title 24 PCTs requires PG&E to: (1) provide in-house services similar to those currently performed by vendors for the SmartAC Program (i.e., program enrollment, deployment, customer service, and load/event management); (2) utilize the two-way AMI network/HAN; and (3) integrate a PG&E-hosted load management system with the AMI infrastructure. To estimate the costs of using the HAN network to communicate with new PCTs, PG&E reviewed the program's current business and technical requirements and estimated the software and labor resource needs required to build the system internally. PG&E anticipates it will incur these incremental AC Program costs in 2011. PG&E estimates the incremental cost of the upgrade to be $14.8 million, which includes $2 million of software costs and $12.8 million of labor costs.

- PG&E estimates it will incur additional costs to integrate the load limiting connect/disconnect switches for all its single phase residential meters with a maximum of 200 amps. Modifications and interface changes will be required to create new credit/collection templates, start/stop algorithms, and partial Load Limiting Functionality. To estimate the cost of these efforts, PG&E used its standard four-phase IT model: pre-build, develop, test, and support. The estimated labor cost of this incremental scope increase is $3.7 million, which is based on PG&E's average, daily, internal and external labor rate of $1,200. PG&E expects to incur these costs from mid-2008 to mid-2009.

- PG&E states the Upgrade will require additional IT project management efforts to support the additional IT work discussed above. PG&E anticipates it will need three additional FTEs from mid-2008 to mid-2011 at an estimated total cost of $2.8 million.

7.5.1. DRA's Position

As discussed further on in this decision, DRA opposes consideration of the PTR program as part of the Upgrade, because DRA feels the PTR program could be implemented in conjunction with PG&E's originally authorized AMI system. For this reason, DRA excludes all PTR benefits and the majority of PTR related costs including $4 million (PVRR) in IT costs associated with the PTR program. DRA states that, if the PTR program is funded in another proceeding, the associated IT cost could be considered there.

DRA also notes that an unnecessary duplication of IT costs has occurred because of PG&E's choice to implement a communication system as part of its

SmartAC program that is duplicative of the HAN communication system. However, because DRA is supportive of the HAN technology, it did not exclude the IT costs associated with HAN communication.

With respect to DRA's exclusion of $4.0 million in PTR related IT costs, PG&E states that the adjustment is a corollary to DRA's position that benefits for the PTR program should also be excluded from the cost/benefit analysis for the Upgrade, and accordingly, if the benefits of the PTR program are included – as PG&E believes they should be – the IT costs for the PTR program should be included as well.

7.5.2. TURN's Position

Similar to DRA, TURN asserts that PG&E's original AMI technology was capable of implementing PTR on a wide scale, and reduces both costs and benefits as they relate to the Upgrade. This includes exclusion of the $4.0 million in IT costs for the PTR program.

TURN also excludes $14.8 million in IT costs requested by PG&E in conjunction with the proposed use of the HAN functionality to communicate with Title 24 building standard compliant PCTs. TURN states that PG&E itself has withdrawn other costs associated with the Title 24 PCT program. Specifically, PG&E assumed in the application that the CEC's proposed Title 24 building standards would begin in 2009, but the CEC later postponed its recommendation. As indicated in its supplemental testimony, PG&E now assumes the standard will be implemented in 2012 and that PG&E will begin recruiting customers in 2013. TURN states that PG&E reduced its Title 24 PCT program cost request by $5.0 million[39] because 2013, the year PG&E begins the program, is outside of the forecast period for this application and argues that the Commission should similarly reduce PG&E's request for the related IT costs.

TURN states that PG&E's current Smart AC Program is the result of a settlement with PG&E, DRA, and TURN that was adopted by the Commission in D.08-02-009. That settlement provided PG&E with sufficient funds to implement a 305 MW direct load control program by 2011. The settlement directs PG&E to come back to the Commission in the second quarter of 2009 with an additional application to extend the program to 2020 - after PG&E has completed and reported certain measurement and evaluation studies required in that settlement. According to TURN, any funds used to supplement the program or change recommendations to that program are supposed to be contained in the application PG&E is directed to file with the Commission in the second quarter of 2009. TURN states that the Commission should require that PG&E honor its end of the TURN/DRA/PG&E settlement and reject any costs for the Smart AC program that conflict with that settlement.

Finally, TURN asserts that PG&E requests ratepayer funds to duplicate processes that it readily admits are already being provided by its vendors. As stated in its application, PG&E wants to "provide in-house services similar to those currently performed by vendors for the Smart AC Program" and operate the program "in parallel to the current vendor provided" program. According to TURN, this is operating a redundant program and a wasteful use of ratepayer funds.

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[39] Reduced costs are related to program administration, marketing, customer incentives and the call center.

In response, with respect to TURN's Title 24 PCT related adjustment, PG&E states that TURN's primary argument, that since PG&E has delayed incurring approximately $5 million in administration and marketing costs associated with the Title 24 PCT program until 2013 or later -- due to the delay in the expected date of the new regulations from the CEC -- so too the IT costs should be removed, has no merit. According to PG&E, the administration and marketing costs associated with the A/C program are distinct from the IT costs. They are for different purposes and are to be expended at different times. PG&E states that under its proposal, the IT work for the A/C program would be performed in 2011, which is still prudent due to the fact that the CEC Title 24 regulations are now expected to be implemented in 2012.

Regarding TURN's other arguments on this issue, PG&E states that first, there is no conflict with the SmartAC settlement, in that, at the time of the settlement, PG&E had notified parties of the possibility that it might file an upgrade to its SmartMeter Program and the settlement expressly envisioned this fact. On this point, the Commission explained,

> [T] he settlement requires PG&E to analyze how to fully integrate the AC Program with its AMI. Integrating the AC Program with AMI will likely increase the value of both programs and expand opportunities for customers to engage in demand response. Therefore, 90 days after the Commission acts on PG&E's pending AMI application (A.07-12-009), PG&E should provide a report to Energy Division, DRA and TURN explaining how PG&E intends to integrate the AC Program with AMI.[40]

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[40] D.08-02-009, p. 13.

PG&E argues it is disingenuous for TURN to suggest that there is conflict with the settlement when the settlement itself expressly envisioned that the AC program could be integrated with the Upgrade. PG&E adds that integration of the AC Program with AMI is what this IT expenditure is designed to do and the costs are neither redundant nor wasteful.

7.5.3. CCSF's Position

CCSF states that PG&E may well have underestimated the true cost of the Upgrade. While the hardware to be installed is the most visible element of PG&E's upgrade, it is common practice in joint development efforts of this kind that hardware engineering often leads software engineering. According to CCSF, many of PG&E's chosen hardware components reflect relatively early stage technology, and some of these components do not yet have software necessary to drive them, or to coordinate their individual functions into the larger web of grid and data management systems. To CCSF, this absence of the necessary software suggests that there will likely be significant systems integration challenges, the complexity and cost of which PG&E may well have underestimated. CCSF is concerned, therefore, that PG&E will at a later date seek to recover even more than the nearly $3 billion the Commission will have approved if this upgrade is authorized.

In response, PG&E states that CCSF makes no acknowledgement of the substantial amount of testimony that PG&E has submitted in the area of IT, which addresses not only the IT hardware, but also the software and system integration needs associated with the Upgrade. PG&E states that it understands and has already articulated the types of risks that CCSF purports to have discovered.

7.5.4. Discussion

As discussed further in this decision, we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade.[41] For that reason, it is also appropriate to include the $4.0 million in IT costs related to the PTR program in rates, as requested by PG&E.

Regarding TURN's proposed adjustment for Title 24 PCT related IT costs, PG&E's argument -- that assigning the costs to 2011 is still reasonable because the CEC Title 24 regulations are now expected to be implemented in 2012 -- is not persuasive. In its application filing, PG&E proposed to spend $6,728,000 in 2010 and $8,105,000 in 2011.[42] Also, it expected to begin recruiting AC customers starting in 2011 and estimated the number of customers for that year to be 16,000 with increasing amounts thereafter (e.g., 47,000 new customers in 2012).[43] In its supplemental testimony, PG&E indicates that it now expects to begin recruiting AC customers in 2013 and estimates the number of customers for that year to be 18,000 with increasing amounts thereafter (e.g., 52,000 new customers in 2014).[44]

PG&E has provided no specific reasons to justify why the IT related costs need to be incurred prior to or in 2011 and why they cannot be shifted commensurate with when the expected recruitment of Title 24 PCT customers is expected to begin. Without such justification, we conclude it is reasonable to shift the costs. We will do so by shifting these costs to 2013 and 2014, principally

[41] *See* Section 10.2.4.

[42] Exhibit 3-4W, p. WP 4-1.

[43] Exhibit 3-5W, p. WP 5-3.

[44] Exhibit 7-W, p. WP 1-71.

to remove such cost recovery from this decision. There is significant uncertainty as to when this program will begin,[45] and we prefer not to authorize related costs at this time. The Title 24 PCT program costs have already been moved by PG&E to 2013, outside the timeframe for cost recovery authorized by this decision. Those costs will have to be recovered in a separate proceeding. PG&E should seek recovery of the related IT costs at the same time.

We do agree with PG&E regarding TURN's allegations of conflicts with the SmartAC program. It is clear that, in D.08-02-009, the Commission expected the SmartAC program would be integrated with the Upgrade. Also, in that decision, the Commission welcomed PG&E's commitment to incorporate Title 24-compliant PCTs into its project and expressed a concern regarding the settlement's 40% limitation on PCT installations.[46] Further in this decision, we address issues related to the inclusion of the Title 24 PCT program in determining costs and benefits associated with the Upgrade.

Finally, we understand CCSF's concerns regarding what may be significant systems integration challenges. However, while nothing is certain, we feel that PG&E's IT proposal is a reasonable means for overcoming any related problems. This is consistent with our authorization of the same advanced metering technologies, with the same integration challenges, for SDG&E and SCE.

7.6. Title 24 PCT Program Costs

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[45] *See* Section 10.4.3.

[46] *See* D.08-02-009, pp.13-14.

PG&E explains that customers with Title 24 compliant PCTs will need to be identified and recruited for participation in the SmartAC Program and there are costs associated with that activity.[47] In addition, the initiative will be reaching out to customers with existing air-conditioning systems for an early change out of the thermostat with a Title 24 compliant PCT. Administrative costs and minor other costs for software and call center support are also included in incremental costs for the program.

Some of the outreach activities considered by PG&E include using new customer connect records for identification of likely new construction sites and purchasing permit records to target market to permitted retrofits. Customer acquisition costs of $53 per participant and $25 sign-up incentives are based on the current SmartAC Program estimates.

Due to PG&E's revised assumed timing of the Title 24 PCT program from 2009 to 2012, costs will occur outside of the time period that PG&E is requesting the related rates as part of this application. For costs through 2030, PG&E estimates costs with a PVRR of $37,906,000.

DRA and TURN have not forecasted the PVRR of any Title 24 PCT program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither Title 24 PCT program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade. As discussed elsewhere in this decision, we have included the benefits of the Title 24 PCT program in evaluating the cost effectiveness of the Upgrade. For that reason, it is also appropriate to include an estimate of the costs through 2030 on a

[47] A description of the PCT program and the associated benefits is provided in Section 10.4 of this decision.

PVRR basis for use in the cost effectiveness analysis. However, consistent with our adjustments for reduced participation to the expected benefits of the program, as discussed in Section 10.4.3 of this decision, we reduce the costs by related marketing and incentive amounts. We adopt Title 24 PCT program costs of $26,174,000 on a PVRR basis, as opposed to PG&E's estimate of $37,906,000.

7.7. Peak Time Rebate Program Costs

The PTR program[48] does not require customers to enroll, however awareness of a critical peak event (the day and time period that PTR as well as CPP will be in effect) is critical to achieve both customer bill rebates and DR resources. PG&E estimates that approximately 50% of residential customers will need to be aware of critical peak events in order to achieve anticipated PTR benefits. According to PG&E, awareness is not an indication of a committed effort. Instead, it provides a proxy for "participation" in the determination of average benefits. PG&E has developed a general strategy for an estimated $7.5 million annual marketing campaign to achieve an average of 50% residential awareness rate of an event without any enabling technology. The media strategy calls for two phases to achieve the objective:

1. Education phase: This includes a pre-summer media and PR effort to raise general awareness of the program; and

2. Event phase: Media and PR during events focused on immediately notifying customers an event is in effect.

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[48] Descriptions of the PTR program and PTR benefits are provided in Sections 10.1 and 10.2 of this decision.

The day of the event activities will include newspaper, spot radio, TV and geo-targeted online efforts. The level of media available is constrained by the fact that events are not known more than 24 hours in advance.

PG&E will begin the PTR program in 2010 and will not have the SmartMeter Program Upgrade technology and features, including interval billing, fully deployed in the PG&E service territory that year. As a result, the marketing campaign will be limited geographically in 2010 and is estimated to cost $3.4 million. Years 2011 and 2012 are estimated at the full $7.5 million annual cost for the two-phase education strategy. Years 2013-2030 have a lower annual estimated cost of $1.8 million due to the assumption of a transition to a more direct method of event notification through in-home displays and enabling DR technologies the customer will choose to install.

DRA and TURN recommend no PTR program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither PTR program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade. As discussed further in this decision, we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade. For that reason, it would also be appropriate to include the $18.3 million in PTR program costs, in rates, as requested by PG&E. However, since this decision approves a two-tier PTR incentive structure that will be detailed by PG&E in a November 2009 rate design window filing,[49] it would be more appropriate to address the costs of such a program at the same time, and we will order PG&E to do so.

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[49] *See* Section 10.1.2.

While PG&E's current PTR program cost estimate of $18,342,000 is for a single tier PTR incentive structure, we will use the related PVRR of the PTR program costs, which amount to $27,592,000, for the purpose of evaluating the cost effectiveness of the Upgrade.

7.8. Project Management Costs

PG&E has forecast $15.3 million in additional project management costs associated with the Upgrade. According to PG&E, these costs are associated with additional project management efforts that will be required as the industry continues to evolve and offer new technologies. PG&E specifically cites additional project management efforts that will be required to deal with the added technological complexity of the HAN, ubiquitous load limiting switch and the advanced solid state meters and to manage additional vendors and the associated issues in contract administration and management of warranties, supply chain issues, costs and benefits realization, and performance metrics.

7.8.1. Positions of DRA and TURN

DRA excluded incremental project management costs completely from its business case, because it believes that what PG&E received in the original case was sufficient. DRA explains that while PG&E asserts that there is additional complexity associated with managing multiple technologies, in its original case, PG&E argued for the need for multiple technologies, one for gas and one for electric, and included the cost to manage the deployment of and operation of these multiple technologies. Since the Upgrade proposes to eliminate the PLC technology, deploying only the Aclara RF technology, and PG&E anticipates introducing a second technology, Silver Springs, DRA asserts that PG&E would still be managing only two technologies as proposed in its original case.

TURN argues that PG&E has not adequately justified its request to increase its project management costs, and the Commission should reject PG&E's request. According to TURN, while PG&E states that the additional funds are supposed to pay for in-house labor costs associated with the increased costs of dealing with more vendors resulting from this "AMI Upgrade" and external professional services to help with in-house project management, risk assessment, and evaluation of PG&E's program management process, with the exception of retrofitting meters with yet unavailable HAN devices and re-deploying solid-state meters to replace stranded electromechanical meters, in general, PG&E is installing the same number of gas and electric meters that were authorized in A.06-07-027. TURN further states that PG&E may have a handful of additional vendors to administer but PG&E has not met its required burden of proof demonstrating that there is a linear function between administering a few more vendors and its proposed increase to program management costs. TURN adds that the rate at which PG&E has been spending its project management and risk allowance funds without installing many meters has led TURN to believe that PG&E's request is premised on the fact that PG&E has squandered its original budget.[50]

In response, PG&E states that it has provided substantial evidence regarding how the additional complexity of the industry and the new project technology will add to its project management costs, and intervenors cannot legitimately ignore the evidence presented by PG&E – that clearly shows a

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50 TURN cites evidence that indicates that, while PG&E has already spent 79% of its authorized project management budget, it has only installed 4% of its forecast electric

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correlation between project management costs and increased numbers of vendors within an increasingly complex industry -- and instead rely on alternate theories that would correlate project management costs with the numbers of meters or networks being deployed.

7.8.2. Discussion

As discussed further in this decision,[51] we determine that PG&E's project management costs associated with the Upgrade should be considered as original AMI program costs, specifically under the risk based allowance. Therefore, for purposes of this proceeding, we need not determine an appropriate measure or theory to guide our determination of incremental project management costs, or whether PG&E's project management to date has been imprudent.

7.9. Operation and Maintenance Expense

PG&E has forecast $5.1 million in operation and maintenance (O&M) costs. These costs include O&M costs related to the load limiting switch, the HAN device and IT. The only category of these costs challenged by intervenors is that relating to expected calls to PG&E's call centers concerning the HAN device. These call center costs – forecast at $455,000 per year through 2010 – are tied to expected rates of HAN adoption.[52] That is, the higher the rate of HAN adoption, the higher the expected call center costs.

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meters and 11% of total gas meter installations. Further, it has only activated 2% of its electric meters and only 1% of its gas meters.

[51] *See* Section 7.12.2.

[52] In rebuttal testimony, PG&E revised its forecast of call center costs in outlying years, but the forecast through 2010 remains the same as set forth in the December 2007 testimony. *See* PG&E, Exhibit 8, p. 3-19, Table 3-1.

DRA's benefit calculations reflect the use of a lower HAN adoption rate than assumed by PG&E. DRA modified PG&E's annual HAN technology adoption rate by a ratio of 21 to 30, which is equivalent to a scalar adjustment of 0.7. This adjustment results in the projected annual adoption rate increases from 0.1% in year 2012 to 21% in 2024. DRA recommends reducing PG&E's call center costs by 70% to reflect the fewer calls that will be received as a result of DRA's lower HAN adoption rate.[53] DRA's adjustment results in a $319,000 reduction in O&M costs.

As discussed further on in this decision,[54] we have adopted DRA's proposed HAN adoption rates, which were derived by applying a 0.7 scalar to PG&E's proposed adoption rates. Therefore, we will apply the same 0.7 scalar to PG&E's proposed call center costs, resulting in an adopted call center estimate of $319,000, which is $136,000 less than projected by PG&E.

7.10. Technology Assessment Costs

In PG&E's original AMI decision, the Commission stated:

> While we recognize that PG&E's AMI deployment meets our functionality requirements as set forth, new technology may emerge that offers PG&E and its customers increased reliability and performance enhancements. We expect PG&E to monitor market place developments so, whenever feasible, it can upgrade its AMI system and offer its customers technology upgrades. (D.06-07-027, p. 52.)

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53 DRA does not explain the apparent discrepancy of recommending adoption of 70% of PG&E's HAN adoption rates but recommending only 30% of the call center costs related to the HAN adoption rates.

54 *See* Section 9.1.4.

In response to this statement, PG&E states that it has closely monitored the advancements in AMI technology advancements. In its application, PG&E proposed technology assessment and pilot costs of $15.4 million through 2012. These costs include approximately $9 million in staffing and other recurring costs and $6.4 million for a pilot test of new technologies.

Considering recent technology developments in communication networks supporting the transfer of information between a utility and its customers' premises, PG&E indicates that it has embarked on a program to identify, evaluate, and test the latest emerging technologies that it may be able to incorporate into its SmartMeter Program Upgrade.

In its May 2008 Supplemental Testimony, PG&E included additional technology assessment costs of $22.5 million for HAN standards development. This consists of $12.5 million for demonstration facility/laboratory testing environment, $5 million for labor for HAN standards support, and $5 million for devices that would enable home computers to function as in-home display devices.

PG&E states that it will continue to work with the other utilities in California and throughout the United States to establish standards for HAN technology and applications and encourage customers to take advantage of the benefits supported by HAN-enabled functionality.

The total of PG&E's technology assessment request is $37.9 million.

7.10.1. DRA's Position

DRA states that given that PG&E's technology assessment request came in response to a Commission directive to monitor the market, DRA has proposed that this program be partially funded. DRA recommends an amount of $9 million (direct nominal dollars). DRA indicates that this figure would allow for the monitoring of emerging technologies. DRA excludes the cost of a technology laboratory, a demo facility for HAN devices, HAN standards work, development of a Zigbee device that can be plugged into a computer, and an ongoing pilot test of the Silver Springs Network.

DRA does not believe there are sufficient benefits in PG&E's business analysis to cover these costs. If the Commission disagrees, DRA would suggest moving up to a figure of $15.4 million, which is what PG&E included in its initial application and testimony in December 2007. That figure would only cover the monitoring of new technologies and the Silver Spring pilot, which is currently being carried out by PG&E anyway.

According to DRA, much of the added work that PG&E proposes is more properly done by organizations such as the Electric Power Research Institute, by national research laboratories, or by consortia jointly financed by several utilities. Furthermore, no other California utility has received an authorization to perform AMI-related research and development work at the same level as what PG&E has requested.[55] DRA states that while SCE may have received more pre-deployment money than PG&E, adding $37 million will clearly put PG&E higher than SCE.

In response, with respect to HAN standards, PG&E cites the cross-examination of DRA's witness who stated it was not unreasonable of PG&E to request the funds for one pilot during the construction of this project. He indicated there might be value to a pilot but objected to the notion of

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55 DRA indicates that SCE received a total of $67 million in pre-deployment funding ($12 million in A.05-03-026 and $45 million in A.05-12-026). PG&E received $49 million,

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establishing the timing and cost in this proceeding. PG&E argues that DRA has not provided any evidence regarding what timing or magnitude of testing is more appropriate than that provided by PG&E, and the only record evidence on this issue supports PG&E's proposal.

With respect to pilot testing, PG&E similarly cites the cross-examination of DRA's witness who stated that he agreed that PG&E should be involved in the HAN standards development process but does not agree that PG&E's cost estimate is the right number. PG&E again argues that DRA has not provided any countervailing evidence regarding what level of commitment is more appropriate than that proposed by PG&E, and the only record evidence on this issue supports PG&E's proposal.

7.10.2. TURN's Position

Regarding PG&E's application request of $15.4 million, TURN recommends that the Commission reject the total amount.

TURN states that when the Commission authorized PG&E's full pre-deployment funding request in A.05-03-016 it did so in part because it felt that PG&E's AMI project was farther along than the other two electric utilities and that PG&E was past the technology assessment phase and required pre-deployment funding to essentially keep its AMI deployment on track. According to TURN, requesting the additional funds to evaluate AMI technology is akin to re-asking the Commission for pre-deployment funding, and PG&E is too far along in its AMI deployment to continue wasting ratepayer money to evaluate new AMI technologies.

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and when the $37 million in technology assessment costs are added to $49 million, the result is $86 million.

TURN also states that D.06-07-027 already requires PG&E to regularly assess AMI technology and to report back to the Commission on its assessments as one of the requirements for receiving authorization of its proposed $1.7 billion funding request, and the Commission has therefore already funded PG&E's technology assessment activities with that $1.7 billion authorization.

Regarding PG&E's supplemental testimony request of $22.5 million, TURN recommends that the Commission authorize $2 million to provide input to and obtain information from private sector projects that will ultimately develop HAN standards.

It is TURN's position that developing HAN standards and functionality to enhance the commercial availability of home area networks is the job of private industry not the ratepayers. Private industry will benefit from selling HAN devices to customers and, therefore, private industry should have the responsibility of developing the technology. In addition, TURN asserts that HAN devices contained within a customer's home are the property of the customer and are not necessarily wholly devoted to managing the energy usage of appliance end-uses. TURN adds that, in the context of an application to redo a multi-billion dollar project a few years after it was authorized, the Commission should not fund extraneous exercises such as this.

In response, PG&E notes the cross-examination of TURN's witness who stated (1) he could not say he had the expertise to understand exactly what was going on in the HAN industry; (2) he did not know how a standard is developed for HAN; and (3) he did not know whether or not a pilot was necessary. PG&E asserts that TURN's recommendation for this cost category is arbitrary and put forth by a witness who acknowledged that he has no specific knowledge or understanding of PG&E's technology evaluation requirements, and, therefore, TURN's recommendation should be rejected.

In response, TURN states the depth of its witness's knowledge of HAN standards development is irrelevant, given that TURN does not believe any of the specific tasks related to its proposed disallowances are necessary for upgrading PG&E's existing AMI system with new meters.

7.10.3. Discussion

PG&E's request has not been fully justified and appears to be excessive.

With respect to its application request of $9.0 million for staffing and recurring costs, PG&E indicates that it is actively evaluating broadband over power line (BPL) and medium-band over power line (MPL) network options along with Internet Protocol (IP) solutions as an approach to expand its network bandwidth and create a more open communications framework. In our previous discussion on network technologies, we gave PG&E latitude on the type of networks to be deployed, with the understanding that it would be within previously authorized budgets. It is not clear that these currently considered communication networks are deficient in particular respects. It is not clear how BPL, MPL or IP would be incorporated into the currently proposed AMI structure.

PG&E did indicate that the backhaul technology is in rapid development and there may be a time when new methods of data transport become commercially viable for deployment. However, while this may warrant continued monitoring, it does not necessarily warrant extensive evaluation processes as proposed by PG&E.

PG&E has not provided convincing evidence that its proposed technology assessment expenditures related to communication networks are necessary or reasonable. However, since there is potential value in having PG&E monitor market place developments, we will authorize $4.0 million for that purpose.[56]

With respect to the $6.4 million pilot testing request, it appears to be related to a network technology that is currently being considered and which may be deployed as part of the Upgrade. There is value in pilot testing to ensure that the proposed network can be integrated into the AMI and will work as intended. We will authorize the requested amount.

With respect to HAN standards development costs, we are in general agreement with the positions of DRA and TURN. Laboratory testing and product demonstrations should first be the responsibility of those in private industry who will in the end profit from the various HAN related devices. Also, some of the work might be done by organizations such as the Electric Power Research Institute, by national research laboratories, or by consortia jointly financed by several utilities. We see no justification for saddling PG&E's ratepayers alone with these laboratory testing and product demonstration costs. However, PG&E has alternatively proposed that for $21 million of its proposed costs, ratepayers would provide half of the amount and PG&E would obtain the remainder from other private or public sources to defray costs that exceed the ratepayer share.[57] We see merit in PG&E's proposal as it relates to laboratory testing and product demonstrations. It is reasonable that ratepayers provide at

[56] For technology assessment, there is no evidence as to what costs might be reasonable for monitoring purposes as opposed to evaluation purposes. The $4.0 million amount for monitoring purposes is based on the assumption that monitoring costs and possibly some evaluation costs would be substantially less than the $9.0 million proposed by PG&E for essentially evaluation purposes.

[57] *See* PG&E Reply Comments on Proposed Decision of ALJ Fukutome, pp. 1-2.

least some of those costs related to protecting PG&E's system from such potential problems as security breaches, interference with bill reading and interruption of customers' service, which can be avoided by first testing devices in a lab that replicates PG&E's system. We will allow $6 million (plus the associated risk based allowance) for this purpose with the understanding that PG&E can use those ratepayer provided funds to the extent that it matches those funds from other sources. Any unspent funds should be credited back to ratepayers.

With respect to the $5 million for labor for HAN standards support, there is value in having PG&E provide input to and obtain information from private sector projects and to interact with developers and other utilities as HAN standards are developed, and we will provide funds to do so.

With respect to the $5 million for devices that would enable home computers to function as in-home display devices, the purpose of these costs is unclear. The funding is for a device that would enable IHD functionality on a home computer but it is included under technology assessment. We are not clear as to whether the device itself is being tested or whether the customers' use of the device is being assessed. If it is the former, we would exclude the costs as being the responsibility of those in private industry who will, in the end, profit from the device. If it is the latter, we see no reason why the device should be free or discounted when, under PG&E's Upgrade proposal, the cost of the IHD is the customer's responsibility. For these reasons, we will not adopt funds for this category.

In total, the adopted technology assessment costs amount to $15.4 million.

7.11. Training Costs

PG&E has included incremental training costs of $1,697,000 for installation vendor software training, Field Automation System training, and customer call center training. No party disputes any of these costs, and they will be adopted.

7.12. Risk Based Allowance

PG&E estimates $506,920,000 in Upgrade costs and on top of this adds an additional $65,533,000 as a risk based allowance or contingency. PG&E indicates that it followed the same approach in calculating its risk based allowance for the Upgrade as it followed in its original AMI application. In D.06-07-027, for that proceeding, the Commission authorized $128.8 million for a risk based allowance on top of $1,610.6 million of estimated project costs. In the Upgrade, the risk based allowance increases costs by 12.9%, while in the original AMI application, the risk based allowance increased costs by 8.0%.[58]

7.12.1. TURN's Position

TURN recommends that the risk based allowance be limited to 7.5%, based on what was authorized in D.06-07-027.[59]

PG&E argues that its risk based allowance estimates are dependent on the category of cost and the specific risk associated with that category of cost. According to PG&E it followed the same procedure as in the original AMI application. That is, certain risk factors were assigned to specific cost categories based on PG&E's perception of what that risk factor should be. The 8% number is a result of assigning different risk factors to different cost categories and

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[58] This overall percentage is calculated by dividing the total authorized risk based allowance by the total authorized costs less the authorized risk based allowance.

[59] TURN calculates the percentage by dividing the total authorized risk based allowance by the total authorized costs.

looking at the results in total. The overall risk based allowance percentage calculated for the Upgrade is higher than that of the original AMI request because the Upgrade has higher amounts of expenditures in the higher risk categories than did the original AMI request.

7.12.2. Discussion

No party appears to object to the concept of a risk based allowance or contingency. Consistent with the outcome of PG&E's original AMI decision, we will adopt the use of such a factor for the Upgrade. We understand that elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts were such things as "the types of equipment that PG&E is proposing to deploy; the maturity levels of the industries that will be providing equipment; vendor experience with similar projects; the timing and scope of the deployment efforts; the current phase of the different contract life cycles; the number and types of vendors that will be managed during the project; equipment failure rates; and other project based factors."[60] We therefore consider these elements as the types of things that should be covered by the risk based allowance for both the original AMI project and the Upgrade.

Consistent with the manner in which the risk based allowance adopted in D.06-07-027 was calculated, we will adopt a risk based allowance for the Upgrade based on the risk profiles of the specific categories of Upgrade costs. That PG&E's estimated overall Upgrade risk based allowance factor of 12.9% is higher than the 8.0% allowance for the original AMI project is a result of PG&E's

[60] *See* Exhibit 8, p. 10-10.

analysis of risk for specific categories of Upgrade related costs as opposed to its analysis of risk for specific categories of costs for original AMI project. We agree with PG&E's position that the analysis of risk for the Upgrade should consider the risk profiles specific to the Upgrade, rather than that of the original AMI project.

Because of the manner in which TURN's recommended risk based allowance factor is derived, there are no specific evaluations of, or agreements or disagreements with, the specific risk factors that PG&E has assigned to the various cost categories. However, it is not surprising that overall risk related to newer technologies included in the Upgrade, in particular the currently evolving HAN technology, and the information technology system integration might have higher risk factors than that for the more traditional technologies that were included in the original AMI project. A review of PG&E's proposed risk factors does not cause any specific concerns with the magnitude of the factors or with the cost categories to which they are applied. We will therefore adopt PG&E's proposed risk base allowance methodology along with the specific factors themselves and the categories of cost to which they are applied.

In adopting PG&E's broad application of the risk based allowance methodology to its cost estimates, for both the original AMI project and the Upgrade, we feel it is vital to fully consider the implications of the risk based allowance concept. Specifically, we must consider if, and to what extent, it can be assumed that the risk based allowances for the original AMI project should cover specific requested Upgrade costs. Also, going forward, we must be vigilant in identifying future costs related to the Upgrade that should be covered by the risk based allowance that we are adopting today, rather than covered by additional rates adopted in another proceeding where such costs might be raised, such as in a future general rate case (GRC).

Regarding future costs that may be related to the original AMI project or the Upgrade and which are raised in separate proceedings for the purpose of additional rate recovery, they are only speculative at this time. We can only note that, in order to get such additional rate recovery, PG&E has the burden to show that such costs are neither covered by the specific costs adopted in either proceeding nor by the risk based allowances adopted in either proceeding.

Regarding requested Upgrade costs that should be covered by the risk based allowance adopted in D.06-07-027 for the original AMI project, two requested Upgrade costs are of concern. They are the incremental project management costs and certain of the costs related to the Kern County electromechanical meter retrofit.

For project management, PG&E requests additional cost recovery for activities related to the newer technologies and an increased number of AMI vendors mostly caused by the added Upgrade functionalities. However, PG&E itself, as described above, includes "the types of equipment that PG&E is proposing to deploy … and the number and types of vendors that will be managed during the project" as elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade, and we see no reason why it should be any different for the original AMI. It follows that these activities are of the type that should be covered by contingencies such as the risk based allowance. It is reasonable that the additional project management costs requested by PG&E as part of the Upgrade should instead be covered by the risk based allowance adopted in D.06-

07-027.[61] The requested amount of $15.318 million ($17.914 million PVRR) will be excluded from the adopted Upgrade costs.

For the electromechanical upgrade, it is reasonable to include the incremental costs of the advanced solid state meter, the integrated load limiting connect/disconnect switch, the HAN gateway device and the installation cost as part of the Upgrade costs. These are the specific costs necessary to provide the functionalities of the Upgrade project and are reasonable. However, the electromechanical upgrade also includes the costs needed to install the approximate 230,000 electromechanical meters that are being replaced by the upgraded devices. The question to consider is whether the stranded costs related to the premature retirement of the electromechanical meters should be absorbed through rates established for the original AMI or through rates established for the Upgrade. The decisions to deploy the electromechanical meters were made by PG&E in conjunction with the original AMI authorization. It is appropriate that the consequences of those decisions should be reflected as part of that same authorization.

Also, as indicated above, PG&E has identified changed timing and scope as elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade, and we see no reason why it should be any different for the original AMI. Changed scope (i.e., advanced meters with higher functionality) is the driving factor that resulted in the electromechanical meters and associated equipment becoming obsolete. It

[61] This adjustment does not apply to information technology project management, which has been estimated by PG&E to be $2.8 million, plus the associated risk based allowance. That amount is included in this decision as an authorized cost.

follows that the costs imposed by the premature retirement of the electromechanical meters are of the type that should be absorbed through the risk based allowance. Those costs were imposed as part of the original AMI project and it is reasonable to assume the related stranded costs should be covered by the risk based allowance authorized by D.06-07-027 for the original AMI project. We will therefore exclude $18.5 million ($20.0 million PVRR) related to the Kern County electromechanical meter retrofit from the adopted Upgrade costs.

8. Operational Benefits

Operational benefits include (1) the elimination of labor costs currently required for manually turning on or off a customer's electrical usage at the premises; (2) bad debt reduction resulting from earlier collection of outstanding balances and earlier shut-off; and (3) cash flow savings from these earlier collections and shut-off. Also, PG&E has identified a tax benefit from meter retirement that is included under this category of benefits.

8.1. Field Technician Labor Savings

PG&E proposes to install integrated load limiting connect/disconnect switches in the solid state meters for all single phase residential meters with a maximum of 200 amperes (amp). While deployment of these switches could begin in the latter half of 2008, for purposes of its benefits analysis, PG&E expects that activation of these switches will occur once enabled through PG&E systems in July 2009.

Electric field technicians typically perform four types of connect/disconnect services at premises with a single-phase residential meter with a maximum of 200 amps: customer move-out, customer move-in, Shut-off for Non-Payment (SONP), and reinstatement of SONP (RSONP). PG&E

estimates that it will realize a total of approximately $6.9 million in incremental operational benefits during 2009 and 2010 that relate to the savings from the elimination of labor costs currently required for manually turning on or off a customer's electrical usage at the premises. That is, PG&E offsets the overall O&M labor savings from the integrated load limiting connect/disconnect switches with the O&M labor savings for the 600,000 disconnect collars it included in the original AMI Application.

No party has challenged either PG&E's inclusion of field technician labor savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.2. Reduced Bad Debt Savings and Cash Flow

According to PG&E, the integrated load limiting connect/disconnect switches will also help PG&E reduce bad debt and improve the timing of cash flow. Each month, approximately 41,000 PG&E residential customers are eligible to be SONP. Due to manpower constraints, only an estimated 13,000 of these 41,000 SONPs (i.e., 32%) are physically turned off each month by sending a field service representative to the premises. The remaining 28,000 (i.e., 68%) are not shut-off and continue cycling for another month. Further, there are two categories of SONPs: (1) those that ultimately remit the balance due; and (2) those that do not and for whom their owed balance must be written-off as bad debt. Based on historical data, PG&E collects approximately 92.2% of SONP balances; the remaining 7.8% are written off.

8.2.1. Reduced Bad Debt Savings

For the SONP balances that are ultimately written off (i.e., 7.8%), the benefit of performing the turn-off remotely is that the turn-off is done more quickly, which results in a lower balance to be written-off as bad debt. The incremental benefits of the load limiting connect/disconnect switch vary, however, depending on whether that SONP would have been processed during a given month. PG&E forecasts that it will realize a total of $1.7 million in bad debt savings in 2009 and 2010.

No party has challenged PG&E's inclusion of bad debt savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.2.2. Improved Timing of Cash Flow Savings

For the SONP balances that are ultimately collected (i.e., 92.2%), the benefit of performing the turn-off activity remotely is that the turn-off is done more quickly, which results in making a collection sooner. That is, the benefit is the time value of money associated with the collections. PG&E forecasts that it will realize a total of $0.7 million in the improved timing of cash flow in 2009 and 2010.

No party has challenged PG&E's inclusion of these cash flow savings as a benefit or PG&E's quantification of these savings. We will include the undisputed amount as part of the benefits adopted by this decision.

8.3. Tax Benefit from Meter Retirement

Since PG&E proposes to replace all existing electromechanical meters with solid state meters, PG&E will need to retire the existing electromechanical meters. PG&E explains that for tax purposes, there will be a loss on the retirement that will be recognized to the extent that the remaining (i.e., undepreciated) tax basis of the assets exceeds the net salvage value, after subtracting the cost of removal. Since for purposes of this calculation, PG&E assumes that the salvage value and removal costs are approximately equal, the loss on retirement would be equal to the remaining (i.e., undepreciated) tax basis of the asset. The associated benefit is the time-value of money associated with receiving a current deduction for the loss on retirement, instead of waiting for the depreciation deduction over time, based on the tax-life of the asset. PG&E compared the present value of the tax benefit associated with the expected depreciation stream of the assets (assuming they remained in service) with the present value of the tax benefit associated with the expected loss on retirement of assets, to derive a net benefit of approximately $11.8 million.

8.3.1. TURN's Position

According to TURN, tax retirement benefits are actually an accounting treatment and not an increase in efficiency or a savings in operational expenses. Essentially, the tax benefits only mitigate the stranded costs that will arise from PG&E retiring all of its existing electromechanical meters. TURN does not consider this to be a "benefit" of the project.

In response, PG&E states that, regardless of the categorization of these benefits, there is no debate regarding the savings to ratepayers that result from these tax benefits. These savings rebound to the benefit of ratepayers through lower requested revenue requirements both in this case and for future proceedings where the tax savings are realized. According to PG&E, whether these tax benefits are categorized as an operational benefit that reduces costs to ratepayers or as an accounting treatment that reduces project costs, the end-result is the same. PG&E argues that TURN's distinction is one of semantics and should be disregarded.

8.3.2. Discussion

No party has challenged PG&E's calculation of this tax retirement benefit. Whether it is identified as a benefit or a reduction to costs, the net effect with respect to a benefit/cost analysis will be the same, and, in either case, that net effect should considered in evaluating the cost effectiveness of the Upgrade. For the purposes of this proceeding, it is reasonable to include the undisputed amount of this tax benefit as a "benefit," and we will do so.

8.4. Remote Programmability

In rebuttal testimony, PG&E raised the issue of a remote programmability benefit. PG&E states that the upgraded meter and communication device will have enhanced processing, storage, and remote programmability benefits that will allow the meters to be upgraded remotely via a network download. According to PG&E, this type of capability will have tangible operational benefits and presents the following example:[62]

> PG&E states that in the next 20 years we can expect computing power needs at the endpoints to increase at a high rate, and that one of the needs and drivers for this computing power is the issue of data, device and operational security. According to PGE, the upgraded meter and communication devices have the ability to be remotely programmed, much like today's modern computers, and the capability to transmit or implement security or functionality patches will be critical to ensuring a reliable and secure network over time.
>
> PG&E believes the benefits associated with the ability to implement this one capability alone through the remote downloading of the necessary software updates and security upgrades to meter endpoint platforms capable of taking advantage of those downloads are significant. According to PG&E, the benefit arises because the ability to remotely reprogram an advanced meter allows PG&E to avoid the need for a field visit to each meter needing reprogramming.

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[62] *See* PG&E, Exhibit 8, pp. 3-17 - 3-18.

> Based on a cost of about $20 per meter, PG&E estimates the cost of reprogramming all of PG&E's 5.4 million electric meters would be $108 million (nominal). PG&E goes on to state there are several reasons that system-wide software upgrades or patches are likely to be required over the 20-year system life. First, there is the issue of security discussed above. Second, there are likely to be several software updates over the course of 20 years. Seven-year replacement intervals are to be expected for many types of software. Furthermore, in between replacements, software and security patches are frequent.
>
> For these reasons PG&E determines it is reasonable to assume that it would have to perform system-wide software patches or replacements at least every three years. Assuming modest labor escalation and system growth, PG&E estimates the incremental benefit of installing endpoints and systems robust enough to handle these expected upgrades remotely to be at least additional $520 million (PVRR) over the 20-year life.

In its opening brief, PG&E states that the significance of this very important addition to the project should not be overlooked.

8.4.1. DRA's Position

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

DRA states that it should be obvious that the pre-AMI meters had no security problems other than a minor amount of energy theft. The meters were mechanical and did not include any components that could be reprogrammed. Hence, no truck rolls were required to change software for the entire stock of meters. DRA also states that the situation is similar with the DSCI system examined in A.05-06-028, since the DCSI system is relatively impermeable to security threats.[63] DRA notes that had there been a security problem, the business case evaluated in A.05-06-028 would have had to include an additional $520 million to cover the cost of such truck rolls, adding there was no money included for this purpose.

DRA asserts that PG&E’s argument collapses into nothing more than a solution to a problem created by the enhanced functionality added by the AMI upgrade. It was not a problem with the system examined in A.05-06-028, or with the pre-AMI meter stock. Thus this benefit does not belong in the benefits stream.

8.4.2. TURN’s Position

TURN also asserts that the Commission should reject the use of this benefit for cost effectiveness purposes. TURN first states that the inclusion of this operational benefit in rebuttal testimony is procedurally incorrect as PG&E raised the issue for the first time in rebuttal and the issue was not responsive to any party’s testimony. TURN then states that the benefits cannot be justified as an incremental benefit of the SmartMeter Upgrade, since the purported costs could not and were not included in the original AMI application. According to TURN, in order to claim a $520 million benefit of avoiding reprogramming costs, PG&E would have needed to be burdened with those costs in the first place,

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[63] *See* PG&E, Vahlstrom, 1 RT 133.

either before the AMI program ever existed or, at least, as part of the original AMI filing. However, the old electromechanical (non-AMI) meters did not require reprogramming nor did the DCSI electromechanical AMI meters require such servicing.

8.4.3. Discussion

We agree with DRA and TURN on this issue and will not reflect remote programmability as a benefit in the Upgrade cost effectiveness analysis. As both parties indicate, the need for reprogramming the advanced meters is caused by the added functionality of the programmable meter itself. The $520 million in potential costs are just that. They are potential costs that never existed. They are avoided because the meter that necessitates the costs can accomplish the task remotely. To assign this purported benefit as an incremental benefit in the cost effectiveness analysis of the Upgrade is illogical and inappropriate.

9. Conservation Benefits

PG&E asserts that the SmartMeter Upgrade Program with the HAN gateway device will enable PG&E to offer a set of information tools to residential customers that will allow for increased energy conservation. That is, the feedback of information on energy usage will increase energy awareness, resulting in a modification of energy usage behavior. PG&E cites a study that reviewed over 100 DR programs and showed residential customers who were provided with daily feedback on their electric usage via the Internet or in-home displays reduced their energy consumption by an average of 11%.[64] Another

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[64] King and Delurey, Efficiency and Demand Response: Twins, Siblings, or Cousins? Public Utilities Fortnightly, March 2005, p. 57.

study that focused on general energy conservation, instead of DR reductions, found feedback on consumption resulting in energy savings ranging from 0% to 20%.[65] The author concluded that "feedback is an essential element in effective learning" and that feedback will have a significant role to play in raising energy awareness and in bringing about reduced consumption on the order of 10%.

PG&E's HAN gateway device will allow a customer purchased device with compatible communications technology to receive near real time information on the customer's energy use. According to PG&E, in most cases today, even with the next day web presentment of interval data (hourly for electric and daily for gas) included in PG&E's original AMI business case, customers evaluating their energy use or efficiency options will use survey or audit tools that must rely on average appliance consumption assumptions. PG&E asserts that (1) getting the consumption rate shortly after turning on appliances like the dishwasher or laundry equipment would have a more immediate impact; (2) customer interest in more detailed information can be inferred by the fact that plug in devices are appearing in retail stores to measure plug load; and (3) near real-time feedback in combination with interval data on the web will provide a powerful diagnostic tool for customers interesting in managing their energy use for financial, environmental or societal reasons.

PG&E estimated conservation benefits starting in 2012 using the following assumptions:

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[65] Darby, Sarah, "Making it obvious: Designing feedback into energy consumption." Proceedings of the 2nd International Conference on Energy Efficiency in Household Appliances and Lighting. Italian Association of Energy Economists/EC-SAVE programme, 2004 and The Effectiveness of Feedback on Energy Consumption, Environmental Change Institute, April 2006.

- A technology adoption curve adapted from historic cell phone annual adoption rates;

- Adoption rates begin at 2% in 2012, top out at 30% in 2024, and remain flat until 2030;

- An average of 6.5% energy conservation for both electricity and natural gas annually for a customer with an in-home display device;

- Average usage per customer is based on PG&E's share of the CEC's 2008-2018 demand forecast;

- Energy forecasts for 2019 through 2030 are extrapolated from the average annual growth rate in the 2008-2018 forecast; and

- PG&E's share of the CEC demand forecast is estimated based on PG&E's 2006 FERC Forms 1 (electric) and 2 (natural gas) sales as a percent of the CEC's area recorded 2006 sales.

9.1. Electric Conservation Benefits

For the time period 2012 – 2030, PG&E estimates an electric conservation level of 10,194 gigawatt-hours (GWh) resulting in a PVRR benefit of $311,881,000, as quantified in the application. That amount would be $384,067,000 if updated for more current energy costs recently incorporated into the E3 model for the 2009-2011 energy efficiency program cycle. PG&E recommends that the Commission should consider the updated amount.

9.1.1. DRA's Position

DRA's estimate of electric conservation benefits is $209 million. DRA's analysis of the upgrade's potential electric energy conservation benefits hinges on three issues: (i) a comparison of the daily information feedback that customers can achieve through PG&E's approved AMI system, as opposed to the real-time feedback that the upgrade potentially provides; (ii) a different annual adoption rate of information display technology; and (iii) a double counting of energy efficiency benefits issue between this application and the energy efficiency program proceeding.

DRA accepts that direct information feedback has potential to deliver conservation benefits, however DRA distinguishes between the effects of real time versus day-late information. DRA argues that day-late information feedback conveyed via the personal computer can be achieved with the already approved AMI system. Furthermore, it is DRA's position that day-late presentation of usage information affects space conditioning usage, as it provides customers with insight into energy used for heating and cooling. DRA cites the work of Lou McClelland and Stuart Cook of the Institute of Behavioral Science at the University of Colorado that concluded, "…conservation actions taken by households with [display monitors] primarily affected energy uses other than heating and cooling."[66]

Using the California Energy Commission 2006 Update to the Residential Appliance Saturation Survey results for the PG&E service territory, DRA calculates that approximately 9.5% of the residential load is attributable to space heating and cooling, with the other 90.5% of residential energy sales attributable to base energy usage. DRA applied the 90.5% scalar adjustment to PG&E's annual residential sales forecast, which discounted the portion of residential sales forecast due to space heating and cooling load, leaving only the base energy

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[66] McClelland and Cook, 1979, "Energy Conservation Effects of Continuous In-home Feedback in All-electric Homes," Journal of Environmental Systems, 9 (2), pp. 169-173.

load in the benefit calculations. This results in a PVRR reduction of $30 million to PG&E's application benefit estimate.

DRA also disagrees with PG&E's use of the cell phone adoption rate to determine such a rate for in-home information display devices, and instead used an adoption rate of compact fluorescent lamps (CFLs), which it considers to be a more analogous historic adoption rate of residential energy efficient technology. DRA made use of a report that examined the effect of customer preference on cost potentials of residential lighting.[67] In the report it was calculated that, by 2005, a cumulative 25% of all residential light fixtures are assumed to be using CFLs. DRA then modified the HAN technology adoption rate by a ratio of 21 to 30, or a scalar factor of 0.7, resulting in adoption rates from 1% in 2012 to 21% in 2024 and a further PVRR reduction of $84 million to PG&E's application benefit estimate.

It is also DRA's position that, if customers do adopt HAN-enabled information feedback technology and conserve electric energy, the energy savings associated with the SmartMeter Upgrade should not be used to justify both the SmartMeter Upgrade cost and the shareholder incentive that PG&E would inevitably earn as the result of the Commission's D.07-09-043 on the shareholder risk/reward incentive mechanism for energy efficiency programs. DRA explains that the electric energy conservation benefits justify dollar-to-dollar the Upgrade project cost and the associated return on equity, and, if not properly accounted, PG&E shareholders would earn another 12% on the same

[67] "Market Failures, Consumer Preferences, and Transaction Costs in Energy Efficiency Purchase Decisions" by Jayant Sathaye and Scott Murtishaw for the Lawrence Berkeley National Laboratory, 2005.

energy saving benefits. Therefore, DRA proposes that 12% of the energy conservation benefits be deducted, to reflect the shareholder incentives PG&E could have earned if the energy savings attributable to the SmartMeter Upgrade were not separately identified from those due to energy efficiency programs. This results in a further PVRR reduction of $24 million to PG&E's application benefit estimate.

Lastly, DRA agrees with PG&E's position that updating the estimate of electric conservation benefits for more current energy costs recently incorporated into the E3 model for the 2009-2011 energy efficiency program cycle is appropriate. This results in a PVRR increase of $35 million to DRA's estimate of electric conservation benefits.

In response to DRA, PG&E argues that DRA's 9.5% adjustment related to space heating and cooling should be rejected. Regarding the 1979 study by McClelland and Cook used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage, PG&E states that a careful review reveals that: (1) it contains no actual data on day-late feedback and space heating and conditioning; (2) its statements about a reduced effect of real-time feedback on those end-uses are inferences; and (3) its interpretation of customer usage differences associated with real-time feedback supports a positive relationship in the study's summer months. PG&E also points out that there is nothing to indicate that day-later feedback was involved or studied, and the only information feedback described in the article was real-time. According to PG&E, lacking actual data, the authors inferred that the monthly differences between the test and control groups' energy consumption "suggest" that the monitors had a greater effect on uses other than heating and cooling. That interpretation, however, is attenuated in PG&E's opinion, given the study's lack of any identified day-late data collection or day-late feedback.

PG&E also asserts that most customers' access to their usage data via the web will be too infrequent to produce conservation benefits DRA claims for day-after information. The evidence indicates that 50% of customers indicate an interest in checking their usage via the internet once a month and, in the Statewide Pricing Pilot, 77% of customers visited the website at some time during the program. According to PG&E, that frequency is no better than the monthly bill that customers receive, and even if day-late feedback were sufficient to produce energy conservation benefits for space heating and conditioning, the majority of residential customers essentially will not use the AMI system's web-presentment next-day functionality for that purpose. According to PG&E, for many of these customers, the Upgrade HAN and IHD will be a better way of providing usage feedback that the customer will frequently see.

PG&E also disagrees with DRA's use of the percentage of residential light fixtures with CFLs to determine an IHD adoption level of 21%. PG&E does not object to the idea of using CFL data to develop IHD adoption levels, but maintains that CFL lamp penetration for fixtures is not an appropriate metric. PG&E argues that since a single household will have multiple light fixtures, it is not appropriate to assume that the percentage of light fixtures is an appropriate proxy for the number of households adopting IHDs, especially in light of the fact that most research to date was done with a single in-home display device per household. PG&E believes that the CFL household adoption is more analogous to the household adoption of IHDs than DRA's use of CFL lamps in fixtures.

While the report used by DRA provided the basis for its estimated assumption about the percentage of all fixtures assumed to be using CFLs, PG&E

refers to a second report cited by DRA entitled "Compact Fluorescent Lighting in America: Lessons Learned on the Way to Market" that reports on an on-site survey of California CFL usage.[68] This report indicates that 57% of homes in the 2004-2005 California Case Study had one or more CFLs installed. PG&E also notes that the 2005 update to the California Statewide Residential Lighting and Appliance Saturation Study found 57% of all homes had one or more CFLs installed, and the 2004 Residential Appliance Saturation Survey for PG&E found 51% of households with at least one CFL. Based on these studies, which show similar household penetrations for CFLs at over 50%, PG&E asserts that its 30% IHD adoption level is conservative and should not be adjusted downward.

PG&E also opposes DRA's recommendation to reduce electric conservation benefits by 12% due to the shareholder risk/reward incentive mechanism for energy efficiency programs, for two reasons.

First, PG&E indicates that even under the current mechanism, the utilities only claim energy efficiency for their energy efficiency program applications under the incentive mechanism; they do not make claims for energy conservation savings. With respect to the Upgrade conservation benefits, PG&E states there is insufficient information to differentiate between energy efficiency program benefits versus other energy conservation. Hence, DRA's adjustment would be too large, even based on their theory.

Second, the scope and structure of the incentive mechanism for 2012 and beyond is unknown at present. In D.07-09-043, the Commission directed the Energy Division to prepare a report by February 2011 so the Commission can

[68] Portions of the report were entered into evidence as Exhibit 22.

consider possible modifications to the incentive mechanism in time for the 2012-2014 program cycle. PG&E indicates there will be many factors to consider, such as the Assembly Bill (AB) 32 framework as well as how the Commission defines the accounting rules for that period. PG&E agrees that there should be no double payment, and that the effect of the SmartMeter upgrade should be factored into the Commission's proceeding when it finalizes the energy efficiency goals for the 2012 and beyond period for the utilities. However, PG&E asserts that the coordination of Upgrade conservation benefits with the energy efficiency incentive mechanism framework for 2012 and beyond should occur when the Commission establishes that framework.

9.1.2. TURN's Position

TURN notes that even though the display is an essential component of the notification protocol for the PTR rates and PG&E also relies upon the device to achieve sizeable conservation benefits, initially PG&E did not include any cost for this device in the application. Rather PG&E assumed that the homeowner will purchase it voluntarily. PG&E presented no evidence as to the cost of this device, and also lacks evidence that the customer will save enough energy to make purchase of the device cost effective. TURN also notes that, while in its supplemental testimony PG&E included $5 million to "promote the specification and adoption of consumer in-home devices" using a proxy price of $20 for an in-home device, no evidence has been provided that $20 is sufficient for an in-home display device of the type PG&E envisions.

According to TURN, evidence shows that devices that provide the benefits PG&E claims will result in conservation cost far more than PG&E indicates. For example, the Kill a Watt device for $25 will only display one device at a time, provides a readout only at the plug, could be hard to use behind a refrigerator, washer, dryer or any other bulky appliance, and is not designed for 220-volt appliances. A more powerful device, such as the Blue Line Powercost to monitor full house usage, is considerably more expensive at $140. According to TURN, only a device such as this is capable of monitoring more than one or a few devices plugged into the same power strip, and only a device of this cost level can monitor heating and cooling systems.

The lack of reasonably priced devices to achieve the benefits PG&E claims causes TURN to question the reasonableness of PG&E's energy conservation benefit.

In response, PG&E states that its data request response[69] on IHD costs ranging from $25 to $235 confirms that the customer would purchase the display himself/herself. PG&E further states that it expects that future costs of simple IHDs will drive even lower and that IHDs costing less than $5 will become available. PG&E elaborates that some customers may want a very simple device that only provides one or two pieces of information, while other customers may want to have more features—for which they will be willing to pay. Also, the existing devices do not use HAN and must have a means of capturing interval load from the meter and displaying the information, such as with a "clamp on CT." In the future, HAN will perform the job of capturing the interval data, relieving the IHD of that function. With HAN, the IHD will only need to perform the receiving and display function, which will contribute to lower IHD costs. PG&E concludes that, as the technology and market develops, the costs of

[69] See Exhibit 203.

IHDs may also be expected to decline, just as the cost of solid state meters has come down significantly between its original AMI case and this case.

9.1.3. CCSF's Position

CCSF agrees with DRA's position that instead of relying on adoption rates for cellular telephones to determine HAN adoption rates, PG&E should have relied on adoption rates for CFLs.

Also, CCSF claims there is no evidence to support PG&E's assumption that its customers will use real time pricing information obtained from IHDs to change their electricity usage patterns. CCSF apparently argues that if customers are not using historical usage information available through web-presentment in the AMI project, there is no reason to think that they will use real-time information from IHDs.

In response, PG&E states there is solid evidence that IHDs do elicit significant conservation by showing customers how much energy they are using. According to PG&E:[70]

> This is because displaying current energy usage in the home will reduce the effort required by customers to monitor their energy usage and correlate energy use changes associated with behavioral changes. Numerous research studies confirm that 'direct feedback,' such as that provided on demand by the customer through the HAN gateway device and a receiving in-home display device, provides more energy conservation than 'indirect feedback' such as monthly bills plus historical feedback. [Footnote: Darby, Sarah, 2004. 'Making it obvious: Designing feedback into energy consumption." Proceedings of the 2nd International Conference on Energy Efficiency in Household Appliances and Lighting. Italian Association of Energy Economists/EC-SAVE programme.]

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[70] Exhibit 3, p. 5-8.

Also, while PG&E and DRA disagree on the IHD impact on space heating and conditioning, PG&E notes that DRA acknowledges that, for other end uses, IHDs do promote energy conservation with respect to over 90% of electric use.

9.1.4. Discussion

To begin, we do not agree with DRA' adjustments for space heating and cooling or for double counting related to the shareholder risk/reward incentive mechanism for energy efficiency programs. Regarding the space heating and cooling adjustment, even if heating and cooling conservation can be accomplished through day-ahead notification, we have previously noted that we will use PG&E's definition of "incremental" for this proceeding. Therefore, since conservation benefits were not quantified in the original AMI proceeding, the conservation benefits we are considering for the Upgrade can result from either the results of the functionality of the original AMI request (day ahead information) or of the Upgrade and the HAN (near real time information). Also, in general, we agree with PG&E's response regarding the 1979 study by McClelland and Cook used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage. In light of PG&E's criticisms, that study does not provide persuasive evidence to support DRA's conclusions on this issue.

Regarding potential double counting related to the shareholder risk/reward incentive mechanism for energy efficiency programs, we note PG&E's assertion that the incentive mechanism relates to energy efficiency and not conservation and that its conservation benefits for the Upgrade include both. Since neither PG&E nor DRA separated energy efficiency from the conservation benefit estimate, we cannot properly apply a factor to prevent potential double counting of energy efficiency. Therefore we will not reduce PG&E's estimate of electric conservation benefits by 12% as recommended by DRA. Instead, when the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, PG&E should ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the Upgrade.

Regarding PG&E's estimate of 30% IHD penetration as opposed to DRA's estimate of 21%, we note that the estimates are based on new technology acceptance curves for different products (cell phones and CFLs). At this point, we have no way of knowing for sure which estimate is better. Both are educated guesses that are not substantially different. However, we will adopt DRA's lower value of 21%. We prefer to be conservative with respect to estimating this benefit partly because of the speculative nature of the forecasts and partly due to TURN's legitimate concerns regarding the cost of the IHD devices. Whether costs will be a significant impediment to customer acceptance is unknown. As does PG&E, we expect the prices of such devices to decline as the technology and market develops, but the economics have not been fully analyzed by any of the parties.[71] There is uncertainty. Therefore, we feel that a reduction to PG&E's estimate of electric conservation benefits is reasonable.

With respect to CCSF's criticism regarding PG&E's assumption that customers will use information obtained from IHDs to change their electricity usage patterns, we feel there is sufficient evidence, as noted by PG&E, to determine that such devices do have that effect. CCSF has not cited any studies

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[71] TURN has not proposed a methodology for quantifying this effect.

or produced any persuasive evidence to rebut those conclusions. Therefore, we will not adjust the estimated electric conservation benefit for that reason.

Finally, both PG&E and DRA recommend that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade, and we agree that it is reasonable to do so.

Based on the above discussion, we will adopt an electric conservation benefit amounting to $268,847,000 (PVRR).

9.2. Gas Conservation Benefits

For the time period 2012–2030, PG&E estimates a gas conservation level of 10,194 billion British thermal units (BBTU) resulting in a PVRR benefit of $167,190,000.

9.2.1. DRA's Position

DRA questions the effect of the electric metering system upgrade on gas conservation, quoting PG&E's statement that the proposed SmartMeter Program Upgrade does not affect PG&E's gas meter infrastructure.[72] DRA also states that PG&E justified its gas system technology and network provider in its original AMI case by stating that its technology provided functionalities that:[73]

> Allow one-way or two way radio communication capability directly to each premise with PG&E gas service; use highly reliable and powerful licensed radio frequency communication channels owned by PG&E; provide 100% coverage for all gas customers in one system; has proven module battery backed by the best proposed warranty; provide daily gas usage with the potential for hourly data for selected customers; provide customer level tamper detection

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[72] PG&E, Exhibit 2, p. 2-5.

[73] A.05-06-028, Exhibit 8-1, p. 1-7.

information; and enable messaging for smart thermostats, in-home displays, and home automation.

It is DRA's position that, since PG&E's gas AMI system was approved in D.06-07-027 and the SmartMeter Upgrade does not pertain to the gas AMI system, PG&E's $167 million claimed benefit of gas conservation is not contingent upon the approval of the SmartMeter Upgrade, and consequently the overall project benefit should be reduced by $167 million.

In response TURN argues that DRA errs in its description of the gas AMI system, and also misses the importance of HAN-enabled in-home information on energy conservation in general.

First, PG&E states that it clarified in rebuttal testimony that its request for the gas AMI system did not include equipment and technology required for in-home gas information display capabilities.

Second, PG&E states that the importance of HAN-enabled IHD is the increased awareness of energy usage occurring at the time in the customer's home. That awareness can extend beyond electrical consumption displayed on the IHD. According to PG&E, experience with residential customer surveys indicates many customers do not clearly differentiate electric and gas consumption by their appliances. PG&E points out that for these customers, the increased awareness of energy use occurring right then-and-there in their homes may encourage immediately cutting back on energy consumption, including gas use. For those customers who are aware of gas versus electric consumption, PG&E states that near-real time HAN enabled IHD information on electric use from motors or fans associated with gas appliances also could support reducing gas consumption by those appliances. Consequently, PG&E asserts that assuming no connection between HAN IHD near-real time information display and gas conservation as DRA has done, takes an overly restricted view of the effects of immediate energy usage feedback on residential customer behavior.

9.2.2. Discussion

We are not convinced that any gas conservation benefits should be attributed to PG&E's original AMI project or to the Upgrade. The IHD shows electricity usage, not gas usage. By looking at the IHD, there is no way to tell if gas usage is high or low or possibly whether any gas is being used at all. If a customer reduces gas usage (e.g., space heating, water heating, drying clothes, or cooking), it is probably for economic reasons. That economic incentive is likely a result of a gas bill or an examination of gas rates rather than a customer looking at an IHD and noting electricity usage patterns.

With respect to customers that supposedly do not clearly differentiate electric and gas consumption by their appliances, there is no record evidence indicating what proportion of the customer base that might be. Furthermore, there is no record evidence indicating whether such customers would be the type that would even purchase an IHD. We cannot accept PG&E's reasoning on this issue as sufficient support for its gas conservation benefit estimate.

PG&E hypothesizes that near-real time HAN enabled IHD information on electric use from motors or fans associated with gas appliances could support reducing gas consumption by those appliances. We only note that a fan being on is one thing, knowing what the gas usage is and whether it is high or low is another thing. Also, it is fairly easy to know whether one's gas space heater is on. If heat is coming out of the vent, gas is probably being used at that time. The same can be said regarding a gas stove. If one is cooking, gas is being used. Neither PG&E's original AMI project nor the Upgrade is necessary to make those determinations. While the IHD can display near real time electricity usage and customers can view that information to determine whether they should cut back or not, the IHD does not display such information for gas. We do not feel that customers' decisions as to whether they should limit or curtail gas usage are significantly enhanced by the presence of IHDs that only display electricity usage patterns.

Therefore, we will assign zero gas conservation benefits in our cost effectiveness analysis of the Upgrade.

10. Demand Response Programs

10.1. PG&E's PTR Program Proposal

PG&E's proposed PTR program would offer new monetary incentives to encourage residential customers to reduce their peak period usage on up to 15 event days per summer. PG&E states that the PTR program is being proposed in part to allow for a consistent residential DR program offering across all three major California investor-owned utilities, and in part to achieve additional DR participation from residential customers who might not otherwise be reached by residential CPP rates alone. By PG&E's proposal, the PTR program will be available to customers starting in summer 2010.

The PTR program would be established as an overlay to the customer's otherwise applicable residential tariff (OAT) by applying bill credits of $0.60 for each kilowatt-hour (kWh) reduced during an event day. The energy reduction from each event will be measured against a customer-specific reference level (CRL) that is calculated for each customer. The proposed peak period times are from 2:00 p.m. to 7:00 p.m. According to PG&E, this approach is similar to those currently under consideration for both SDG&E and SCE, but has been adapted to comport with PG&E's adopted residential CPP program -- the residential CPP and PTR programs offered to PG&E's residential customers would match both in terms of operating hours (2:00 p.m. to 7:00 p.m.) and pricing level ($0.60 per kWh). PG&E also anticipates initiating CPP calls and PTR events on the same summer peak days.

According to PG&E, due to AB 1X,[74] residential customers currently cannot be placed on a mandatory rate schedule or overlay that can result in higher bills for Tier 1 and Tier 2 usage. PG&E argues that the limitations created by AB 1X mean that dynamic pricing programs that could potentially increase customer bills (e.g., CPP) may only be offered to residential customers on a voluntary basis.[75]

PG&E states that until the AB 1X restriction is lifted, PTR will be a preferred choice for maximizing DR from residential customers.[76] Because there is no downside risk, PG&E recommends that all residential customers be automatically enrolled in PTR once they are fully connected to the network, unless they are enrolled in CPP. PG&E reasons that automatic enrollment in PTR overcomes the hurdle of inertia (i.e., maintaining the status quo) that comes with recruiting customers onto a new program. In addition, the positive

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[74] AB1X refers to Assembly Bill No. 1 from the 2001-2002 First Extraordinary Session as codified by Water Code section 80000 et seq. Water Code section 80110 protects the rates of residential customers for usage up to 130% of baseline quantities "until such time as the [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation's retail end use customers…."

[75] In D.06-07-027, the Commission ruled that residential customers may waive their AB 1X protections to participate in voluntary tariffs that give customers an opportunity to lower their bills.

[76] According to PG&E, an affirmative waiver of AB 1X protection for the PTR program would be unnecessary because (unlike with CPP) there is no potential for charges to increase for usage billed at Tier 1 or 2 rates; customers who do not earn a rebate simply continue to pay their normally applicable rate.

reinforcement provided by a "carrots only, no sticks" approach facilitates customer acceptance, since it will guide them towards understanding dynamic rates without the possibility of a higher bill.

As with the CPP program, PG&E proposes to restrict eligibility to individually-metered bundled service customers. Master-meter accounts would be excluded from the program because it would not be possible to determine load reductions for individual tenants. Net-metered accounts would be excluded from PTR because these customers' loads are served by a combination of their own equipment and utility generation, and it would not be possible to evaluate demand reductions for such customers independently of changes in output from their customer-owned generation equipment. Finally, direct access and community choice aggregation customers would be excluded from PTR (just as they are excluded from participating in CPP), because the generation portion of their service requirements is provided by third parties.

PG&E has evaluated potential interactions between the CPP and PTR programs, with the expectation that customers may want guidance in helping choose between these two demand response participation options. Its analysis shows that customers who are believed to have significant central air conditioning (CAC) usage would divide almost equally between finding CPP vs. PTR participation most advantageous. Also, nearly 90% of customers who are not believed to have significant CAC usage would be better off on CPP than under PTR. Nonetheless, PG&E does not expect high levels of initial CPP enrollment from customers without CAC, because non-CAC customer savings under CPP would still be relatively modest and because PG&E's marketing efforts for CPP will be focused on customers with significant CAC loads.

PG&E explains that customer bill savings associated with the PTR program will be attributable to two factors: "structural" savings, and savings attributable to actual demand reduction efforts undertaken in response to PTR calls. Structural savings are sometimes referred to as "free rider" savings. In the context of the PTR program, these are rebates that customers would receive as a consequence of ordinary variation in their daily energy usage (e.g., if they happen to be on vacation on the day a PTR event is called, but were home during the period reflected in their CRL allowance). Customers will realize additional bill savings under the PTR program if they initiate real demand reduction efforts in response to PTR calls. In practice, each customer will realize a combination of bill savings under PTR (structural and demand response), although such effects must be estimated statistically and could never be measured independently for each household.

PG&E proposes to estimate the structural component of PTR savings for the residential class, using the best available load research information when rate updates are prepared for January 1 rate changes each year. This structural savings estimate would then be treated as an external adder to the residential class cost allocation for the purpose of setting generation rates, so as to prevent non-residential customers from having their own rates affected by the cost of the free-rider portion of rebates received by residential customers. (The first such estimate would be prepared in the fall of 2010 and will then be reflected when rates are set for January 1, 2011.) After providing for this adjustment for the structural component of the rebates, PG&E proposes that all actual rebates be recognized as reductions to revenues from generation rates. This approach is based on an assumption that the demand response component of PTR bill savings will be in reasonable accord with procurement cost savings that can be attributed to the program.[77]

10.1.1. DRA's Position

DRA recommends that approval of the proposed PTR program should be separated from a review of PG&E's proposed AMI Upgrade system. DRA recommends that the Commission approve the PTR program with modifications in the 2009-2011 Demand Response Programs and Budget Application.

Regarding program design, DRA recommends that the Commission adopt a two-level incentive structure to minimize free-ridership, as DRA recommended for SCE and SDG&E's PTR program proposals, and as adopted by the Commission for SDG&E's PTR program in D.08-02-034. Furthermore, PTR program measurement and evaluation should conform to the demand response load impact protocols adopted in D.08-04-050. Specifically, DRA emphasizes the ex post assessment of free-ridership and the distribution of load impact across customers.[78]

PG&E opposes DRA's proposal to address PTR in PG&E's 2009-2011 demand response (DR) program case. According to PG&E, the 2009-2011 DR

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[77] According to PG&E, this approach will reduce revenue accruing to the Utility Generation Balancing Account (UGBA) by the demand response component of PTR bill savings (total PTR rebates net of the free ridership adjustment), simply because the UGBA is the generation-related account to which revenues accrue residually. This may produce a modest mismatch between generation-related accounts, since PTR-related procurement savings would most likely be realized as reduced costs in the Energy Resource Recovery Account (ERRA). PG&E states that while this is a factor which PG&E and the Commission might wish to weigh when reviewing future UGBA and ERRA balances, it would not affect total generation rates or the division of costs between different groups of customers.

[78] DRA's recommendation is detailed in Exhibit 108, Ex. 5, Ch. 5B.

case is a consolidated proceeding for PG&E, SCE and SDG&E and it needs to move forward expeditiously to allow the next cycle's DR programs to proceed in time for customers (primarily commercial and industrial) to know what will be offered and to decide whether they will participate. PG&E states that adding the DRA PTR proposal to that case would unreasonably delay the timetable and expand the scope of the 2009-2011 proceeding.

PG&E notes that the SDG&E and SCE PTR proposals have been moved to those utilities' respective GRCs, but if PG&E's PTR were moved to Phase 2 of its next GRC, implementation would be delayed beyond summer 2010, the program start date. PG&E also notes that the Commission specifically stated that PG&E's Upgrade case is an appropriate forum to consider PTR.[79]

With respect to DRA's proposed program design, PG&E states that DRA's proposal is flawed conceptually and lacks critical details. In the absence of any presentation of these details, the DRA recommendations should be rejected.

DRA's description of its higher and lower PTR incentives raises the potential for the higher PTR incentive to exceed avoided cost, which PG&E cautions should not be allowed to happen. PG&E is also concerned about practical issues for establishing, enforcing and monitoring a two-tier incentive program. For instance:

- How will the required technology measures be identified (and updated)?
- How will individual customers' adoption of such measures be known and confirmed?

[79] *See* D.08-07-045, Conclusion of Law 23. D.08-07-045 addresses the dynamic pricing phase of PG&E's last Phase 2 GRC.

- How would continued on-going operation of installed measures on the customers' individual premises be monitored?

PG&E also notes the additional costs to implement, market and administer a DRA two-tier, technology enabled PTR program, beyond what PG&E has requested for a single-tiered PTR incentive.

10.1.2. Discussion

We believe the PTR program will encourage residential customers to reduce their peak period usage on peak days. We also agree that the program is allowable while the AB 1X rate protections remain in place. However, the PTR program should be regarded as a transitional program that the Commission intends to review when the AB 1X rate protections change.[80]

As discussed in other parts of this decision[81] the costs and benefits of PG&E's proposed PTR program will be considered in the cost effectiveness analysis of the Upgrade. We would also prefer to address the program design as part of this proceeding. As DRA indicates a two-tier design has been adopted for SDG&E.[82] Also, a two-tier settlement proposal for SCE has been deferred to

[80] D.08-07-045 orders PG&E to "file an application proposing a default CPP rate for residential customers 30 days after any change in the law that changes the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers. If the Commission approves a decision that interprets the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers, then PG&E shall file an application proposing a default CPP rate for residential customers not later than 90 days after the Commission decision goes into effect and is no longer subject to rehearing or judicial review."

[81] See Sections 7.7 and 10.2.4.

[82] *See* D.08-02-034, p. 22.

SCE's Phase 2 GRC proceeding.[83] We are therefore reluctant to move forward with PG&E's single tier proposal. In other sections of this decision, we emphasize consistency in how we treat the IOUs. We see no reason to stray from that principle in this instance and will adopt a two-tier design for PG&E. However, we do acknowledge that the details of DRA's proposal are lacking and there are a number of practical considerations that would need to be addressed. For that reason, we will defer the PTR program design to PG&E's November 2009 rate design window filing, where we will require PG&E to propose a two-tier PTR incentive design and the associated PTR program costs for such a design. This will allow PG&E time to (1) work with DRA and other parties to work out program details and costs; (2) consider the adopted design for SDG&E along with any solutions to practical considerations, if any; and (3) monitor and evaluate what has happened or will happen in SCE's Phase 2 GRC with respect to implementing a two-tier PTR program design. Hopefully, this cooperative effort will allow time for the Commission to adopt and implement a two-tier design for PG&E in time for the anticipated Summer 2010 start of the program. If it turns out that this is not possible, PG&E's PTR program should instead be implemented in 2011. PG&E's rate design proposal should be consistent with the rate design guidance adopted in D.08-07-045.

10.2. PTR Benefits

The PTR benefits are calculated by PG&E with the same price elasticities as the CPP program using the model developed from the AMI business case in A.05-06-028. The model in this application assumes a total participation rate on

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83 *See* D.08-09-039, p. 38.

both PTR and CPP of 50 percent of the residential customer sector based on PG&E's proposed awareness marketing. Estimated CPP participation is subtracted out annually and the residual MW reduction is estimated as the incremental DR benefit attributable to the PTR program. PG&E forecasts avoided capacity of 6,307 MW through 2030. PG&E values the avoided generation capacity costs at $85/kW-yr.

10.2.1. DRA's Position

In considering the demand response benefits PG&E attributes to the Upgrade proposal, DRA argues that the Commission should consider the metering functionalities needed to implement the proposed PTR program, and compare that to the added functionalities offered by the Upgrade. Specifically, if PTR implementation does not depend on the added functionalities, particularly the HAN gateway and the integrated service switch, then the PTR costs and benefits should not affect the Upgrade cost-benefit analysis.

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

(1) Notify customers the day before a peak event day, and

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

DRA examined Commission records and PG&E's original AMI application prepared testimony exhibits, and concluded that the listed requirements for the proposed PTR program can be met with the already authorized AMI system, without the added Upgrade functionalities. DRA recommends that the $290 million PG&E includes in its benefits calculations for PTR should therefore be excluded.

In response to DRA, as well as TURN who makes essentially the same recommendation, PG&E states that both DRA and TURN completely fail to recognize the value of HAN and IHDs to reach more customers and communicate most effectively with them, which is necessary to achieve the desired result of an effective PTR program.

10.2.2. TURN's Position

TURN believes that any benefit from PTR rates is not incremental to the hardware requested in this application but could be obtained (albeit at higher marketing and IT cost) from the functionality specified for existing hardware. In the event that demand response benefits from PTR are considered, it is TURN's position that those benefits, as estimated by PG&E, have been significantly overestimated. TURN provides three basic reasons for this position.

First, TURN calculates an AC adjustment factor to incorporate its assertion that AC loads will be decreasing over time as more efficient air conditioners are installed according to federal regulations. According to TURN, the movement from an average SEER[84] rating of SEER 10 to SEER 13 at the end of 20 years means that the stock of CAC units will result in less demand per unit over time, thus a smaller starting point from which to undertake demand response. TURN argues that use of its SEER rating adjustment is more appropriate than PG&E's position of no AC adjustment.[85]

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[84] SEER is the Seasonal Energy Efficiency Rating, defined by the Air Conditioning and Refrigeration Institute. Higher SEER ratings are more energy efficient.

[85] TURN states that while its witness, Ms. Schilberg, conceded upon cross-examination that the AC adjustment factor could involve a slightly smaller derate than appears in TURN Ex. 211, p. 16, the AC adjustment factor was erroneously omitted from its adjustments to the expected PCT MW. TURN states that it considers these two factors

Footnote continued on next page

Second, TURN argues that PTR demand response calculated with the use of unadjusted CPP elasticities will overstate response from PTR rates.

From a theoretical perspective, TURN argues that *a priori* one would expect customers to consume less under a CPP rate than under a PTR rate. That is because under a CPP rate, the charge on each kWh consumed during the peak period on an event day is the OAT plus the CPP adder of 60¢/kWh. So if the OAT is 16¢, a customer would be charged 76¢ for each kWh consumed during the peak event (a "stick," accompanied by a "carrot" of tariff reductions on other kWh consumed). Under a PTR rate, the customer is charged the OAT on each kWh consumed during the event peak period (e.g., 16¢), but receives a credit of 60¢/kWh for each kWh saved compared to a reference level. TURN states that while the marginal incentive to save a kWh is the same between the CPP and PTR rates, the marginal price to consume a kWh is far higher under the CPP rate (76¢) versus the PTR rate (16¢). TURN interprets this to mean that the consequence of peak consumption under CPP rates is likely to be more attention-getting for the customer, and that expensive consumption will run into the customer's budget constraint. On the other hand, the customer under PTR rates faces no adverse consequence from continuing to consume, and that extra consumption at the lower OAT does not impact budget constraint."

TURN also argues that quantitative evidence supports the theoretical understanding that CPP customers will save more energy than under PTR rates. According to TURN, the only study that examines both rates, using the same incentive for CPP and PTR on the same days (same weather), is the Ontario

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to be offsetting, and this decision assumes that TURN's total SEER related adjustment is reflected in its PTR adjustment.

study.[86] In that study customers under PTR rates saved 30% less than CPP customers. TURN states that although the statistical results do not enable a conclusion that the CPP and PTR savings rates are statistically different from each other, the lower PTR value supports TURN's theoretical understanding and is evidence that must not be discarded lightly. For these reasons, TURN recommends that it would be reasonable to adjust the CPP elasticities downward by 30 percent for PTR purposes.

TURN also argues that evidence from customer surveys supports its position that PTR customers will save less than CPP (SmartRate) customers. In citing a recent PG&E study,[87] TURN states the survey shows that 22% of customers were interested in signing up for CPP rates, and that they are "more involved in energy than the average customer –they are more motivated to conserve, they want more control, and they are more receptive to getting help from PG&E to reduce their energy use further…tend to be under 55 years old, higher educated, more affluent, with families, with higher than average energy bills…" Also, although 47% of customers said they would sign up for PTR (SmartRebate), they are "less interested in controlling their energy use, they are less likely to think they can reduce their energy use weekday afternoons without too much inconvenience, and they are less likely to want to think about or track their energy use. SmartRebate customers also differ demographically from those who say they would sign up for SmartRate. Both groups tend to be customers

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86 IBM Global Business Services and eMeter Strategic Consulting for the Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report" July 2007.

87 Hiner & Partners, Inc., "Pacific Gas and Electric Company 2007 Rate Option Survey," August 2007.

who are under 55 years old, but in nearly all other respects customers interested in SmartRebate are very much like the average of all customers. They do not stand out in any respect other than being somewhat more likely to be on the CARE rate." According to TURN, it is clear from the customer surveys that those signing up for the PTR rate will be far less interested than CPP customers in saving energy and thus will not produce the same savings that can be expected from CPP customers.

Also, TURN expects that participation in PTR will fall off over time, because (1) customers value financial savings, and the small savings available will not maintain participation in the long run; (2) a disadvantaged customer needs to reduce energy by more than 15% before even earning a rebate on at least one-third of the event days, which will defer many customers; and (3) default PTR customers are not committed to demand response.

TURN also disagrees with PG&E's assumption that its notification strategy will reach 50% of the residential customers regarding critical peak time events for PTR and CPP rates combined. TURN indicates that while PG&E expects to provide direct notification to customers of event days via devices such as in-home displays beginning in 2013, PG&E expects that market adoption of the in-home display will reach 3% of customers by 2013 and top out at 30% of customers in 2024. TURN argues that even at maximum penetration (30%) the in-home displays cannot be relied upon to assure 50% awareness for PTR/CPP rates in the near future.

TURN also states that the fact that PG&E intends to make 50% of its customers "aware" of critical peak events is not an assurance that 50% of its customers will behave as did customers who were enrolled in the SPP pilot. While TURN did not make an additional adjustment for this factor, it states that this is another source of overestimates in PG&E's projections, which the Commission should keep in mind in judging the merits of PG&E's demand response benefits.

Also, as a consequence of PG&E's 50% participation assumption, TURN understands that PG&E implicitly assumes 45% of its non-CAC customers will participate in PTR.[88] TURN states that expecting these customers to participate in PTR for the next 20 years is not supportable because (1) non-CAC customers have small usage; (2) financial savings from demand response are small; and (3) non-CAC customers are unlikely to have in-home display devices. TURN states that PG&E has no basis for assuming demand response of 104 MW from non-CAC customers in 2012, up to 129 MW in 2027. Since SPP data show that roughly 26% of participants identified non-financial reasons for their participation, TURN expects that participation in PG&E's PTR program is like to be a maximum of 26% of non-CAC customers, rather than the 45% PG&E assumes (adjustment factor = 58%).

In summary, TURN expects a maximum of 142 MW from PTR in 2012 (55% of PG&E's 260 MW estimate), and 162 MW in 2025 (49% of PG&E's 328 MW estimate).

In response, with respect to TURN's assertion that increases in federally mandated SEER from 10 to 13 would increase the energy efficiency of CAC units while higher saturations of "more efficient" CAC units would reduce the peak demand response potential from future CAC installations and retrofits, PG&E states that TURN's argument ignores a well-established body of evidence that

[88] Exhibit 211, p. 18.

SEER is not a reliable predictor of energy performance in California or of demand reduction. PG&E states that the CEC report cited by TURN for the increase in SEER ratings is replete with statements about the inadequacy of SEER ratings in California. For instance, the CEC report states: [89]

> Current HVAC appliance performance testing is conducted to national standards. Standard ratings for the seasonal energy efficiency ratio (SEER) are conducted at a maximum temperature of 82° Fahrenheit and treat dehumidification as equal to sensible cooling. In the hot dry climates of California, outside air temperatures over 95° Fahrenheit with 35% relative humidity is common. The current standards provide inaccurate assessments of energy requirements during peak periods in California and the Southwest.
>
> Peak energy use is further amplified by the natural tendency of designers and contractors to provide a larger capacity system than necessary, resulting in excessive and inefficiency cycling of the compressor. Increased cycling of a direct expansion air conditioning system reduces overall efficiency through cycle start-up losses which occur until the cold liquid refrigerant returns to the evaporator coil. The results of over sizing single-speed units include increased electric peak and, in some cases, increased energy consumption.

PG&E indicates that the bottom line of the CEC report cited by TURN is that:[90]

> [T]he state should investigate a new efficiency metric for residential and nonresidential direct expansion, air cooled air conditioning system that appropriately rates performance in hot and dry California climate zones.

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[89] See PG&E, Ex. 25, p. 24.

[90] *Id.*, p. 25.

PG&E also states that Exhibit 218 that was introduced by TURN echoes the findings of Exhibit 25, wherein it states, "Neither SEER nor EER is a sufficiently reliable indicator of cooling energy performance (consumption or demand) for California."[91]

With respect to TURN's proposed 30% reduction in SPP elasticities, PG&E states that the standard error for both the CPP and PTR Ontario study results was 8%, and:

> Thus, the difference between the two values is less than one standard deviation, which is much less than the two standard deviations required to demonstrate that the difference is statistically significant. Put another way, the empirical evidence from the Ontario pilot does not support the claim that the impacts estimated using the SPP demand models should be reduced by 30%—indeed, the empirical evidence shows that there is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population.[92]

PG&E also points out that the Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the demand models from the SPP (after controlling for air conditioning and climatic differences between the Anaheim and SPP samples), and the convergence of the Anaheim PTR results and the SPP model results corroborate the Ontario study's finding of no significant difference between PTR and CPP impacts.

With respect to TURN's argument that non-CAC customer usage is small and savings will be small, PG&E argues that, while the average PTR benefit for a

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[91] Exhibit 218, p. 25.

[92] PG&E, Exhibit 8, p. 9-3.

non-CAC customer may be small, there are a range of customers both above and below the average with many distributions possible. PG&E indicates that if the average benefit were $1.50 per month, there could be scenarios where half the customers reduced load enough to get a $3.00 saving or where 25% of the customers respond sufficiently to get a $6.00 bill savings. Moreover, if the customers are in tiers 4 or 5, their savings could even be greater.

With respect to TURN's assumption that a customer must purchase an IHD to participate in PTR, PG&E indicates that it has budgeted funds to provide continued support of education and event notification, such as public service messages and press releases. Thus, according to PG&E, although IHDs are critical as an additional notification channel, a portion of PG&E's customers (particularly in high density urban areas like the San Francisco Bay Area) may learn about PTR events through other media. PG&E does agree that a large percentage of customers will participate for environmental or societal reasons, but does not agree that participation for non-CAC customers should be limited to only that group.

10.2.3. CCSF's Position

CCSF agrees with DRA that PTR implementation is not dependent on real time communication with customers. According to CCSF, using PG&E's website or the media to send out notices of a PTR event could be just as effective as PG&E providing notice through its customers' IHDs, and the added functionalities provided by the HAN are not an additional benefit of PG&E's proposed AMI upgrade.

The City also agrees with TURN, that there is no evidence to support PG&E's claim that its customers will respond to PTR rates in the same way they do to CPP rates.

10.2.4. Discussion

With respect to DRA's position, as indicated previously in this decision, we are accepting PG&E's definition of "incremental" for purposes of determining Upgrade costs and benefits. Since PTR benefits result from PG&E's SmartMeter project and were not quantified in PG&E's original AMI proceeding, we will do so now as part of determination of the cost effectiveness of the Upgrade.

With respect to TURN's recommended adjustments, in the event that PTR benefits are considered, we agree, to an extent, that demand response related to PTR will likely be less than that estimated by PG&E.

PG&E has provided persuasive evidence to justify its position that SEER is not a reliable predictor of energy performance or of demand reduction in California. We interpret that to mean, for instance, if a customer upgrades from a unit with a SEER 10 rating to a SEER 13 rating, which reflects a 30% increase in the rated efficiency of the equipment, the customer will probably not realize a 30% reduction in demand or 30% energy savings. Demand reduction and energy savings will likely be lower. However, we do not interpret this to mean there will be no energy savings or reductions in demand at all. For example, in Exhibit 218, Figure 12 shows median savings, ranging from 6% to 33%, associated with upgrading from a lower SEER system to a higher SEER system under different upgrading scenarios, although the number of units achieving expected savings is low (from 8% to 29%). Therefore, even though the climate and other factors particular to California are not the same as that assumed for SEER purposes, it is reasonable to assume that as manufacturers attempt to make more efficient systems to comply with upgraded SEER levels, there will be some effect of demand reductions and energy savings in California. We will reduce TURN's proposed adjustment by 50% to reflect this effect.[93]

With respect to TURN's proposed 30% elasticity adjustment, we are convince by PG&E's arguments that there is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population, and the Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the demand models from the SPP. We will therefore not adopt TURN's recommended adjustment. This is consistent with our actions in SCE's AMI proceeding where a similar TURN proposal was rejected and where we stated:

> Current evidence does not provide a definite picture of customer behavior under a PTR rate, since such rates are not currently in widespread use. However, based on existing evidence it is reasonable to conclude that the elasticity of customer electric demand under a PTR rate may be comparable to under a CPP rate. Similarly, though it is not possible to be certain how customers will react to a PTR rate on a long-term basis, it is reasonable to apply economic theory to this question and assume that long-run elasticities will not be lower than short-run elasticities. Over the long run, for example, customers may have access to more enabling technology allowing them to respond more easily to PTR rates and increase their resulting demand response. For these reasons, the elasticities used in the settlement agreement business case, which are based on elasticities calculated from CPP rates and are assumed to remain stable over time, are reasonable for the purposes of

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[93] TURN assumed a 30% increase in efficiency when moving from SEER 10 to SEER 13. Based on the information in Exhibit 218, Figure 12, and the general concerns related to using SEER for such purposes, a 15% increase in efficiency appears reasonable.

> estimating future energy savings from PTR rates and their associated benefits.[94]

With respect to TURN's non-CAC customer participation adjustment, we understand TURN's concerns regarding limited savings. While PG&E demonstrates that a non-CAC customer might realize significant savings under the PTR program under certain scenarios, there is no evidence as to suggest what the expected scenario might be and what savings would result from such a scenario. We do agree that there will likely be a response beyond that of those who would participate for environmental or societal reasons and assume for purposes of this analysis that it is halfway between that estimated by TURN and that implicit in PG&E's forecast. This results in a non-CAC customer participation rate of 35.5%.

Based on the above discussion, we adopt PTR savings through 2030 in the amount of 5,714 MWs as opposed to PG&E's forecasted amount of 6,307 MWs. This results in a PVRR benefit of $262,941,000 as opposed to the PG&E's $290,222,000 estimated amount.

10.3. TURN's Demand Response Guarantee Proposal

In TURN's opinion, the implementation of a PTR rate is likely to undermine customer participation in the CPP rate which was approved in D.06-07-027, and there is a danger that the benefit stream upon which approval of the initial AMI project was based will not be fully realized. Also, TURN estimates demand response benefits that are 40%-49% of the MW that PG&E projects, reducing projected benefits by at least $222.5 million. For these reasons,

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94 D.08-09-039, p. 30.

TURN believes there is a significant probability that not only will the benefits of this application not be realized, but also the benefits approved in D.06-07-027 will be diminished. It is TURN's position that failure to fully realize the projected demand response in both projects – the initial AMI project and the Upgrade-- doubly harms ratepayers by not only saddling them with costs that are not accompanied by benefits, but also requiring ratepayers to purchase expensive power at peak times to replace the unrealized demand response. TURN also indicates that, because demand response and conservation benefits account for 85% of the Upgrade benefits, failure to achieve 100% of these amounts has a large impact on the benefit/cost ratio.

In light of these considerations, TURN recommends that, if the Commission proceeds with any part of PG&E's Upgrade application, PG&E should be required to adhere to the following guarantee:

> Failure to achieve 65% of the MW savings approved in D.06-07-027, and 100% of the additional PTR and PCT MW projected in this application (see Table below) should result in penalty payments to ratepayers. The penalty should equal one-half of the annualized cost of a peaking powerplant adjusted for losses (and for reserves if applicable at the time) multiplied by the unachieved savings for each year of underachievement.

In summary, PG&E opposes TURN's penalty proposal as inappropriate in this case. First the time, effort, expertise and focus needed to address the complex issue of shareholder risks and rewards for demand response is beyond the scope of this proceeding. Second, TURN's penalty-only proposal is arbitrary and has no sound justification. And third, as the Commission did not adopt this type of mechanism in its original decision on PG&E's AMI application, it would be unreasonable to introduce a penalty mechanism now, two years later.

PG&E adds that forecasts of avoided costs, other costs, benefits, and the metrics for measuring them out into the future should be expected to change over time, with more experience. For instance, the Commission may institute new programs that take advantage of the upgraded elements of PG&E's SmartMeter system to obtain new benefits.[95] PG&E points out that the Commission has extensive review and approval oversight for demand response, where it can take corrective steps that may be appropriate at the time. PG&E also notes that future increases in the economic value of the demand response could produce values exceeding those estimated in this case, even if the forecasted MWs are not achieved. So, under TURN's MW approach, PG&E could be penalized even though the value of the demand response achieved was higher than forecast in the case.

10.3.1. Discussion

We will not adopt TURN's demand response guarantee proposal. First of all we have adjusted PG&E's PTR and Title 24 PCT program benefit estimates to what we feel are reasonable levels, in light of the record of this proceeding. Also, a similar issue was addressed recently in SCE's AMI proceeding, where TURN proposed that the Commission should also adopt a penalty mechanism under which SCE would be required to pay a penalty in the event that it failed to reach 65% of its forecast demand response. TURN recommended a penalty mechanism equal to one-half of the annualized cost of a peaking power plant

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[95] PG&E points to the requirements for PG&E's February 2009 rate design window filing contained in D.08-07-045 that suggest that the Commission has more dynamic rate options in mind.

adjusted for losses and multiplied by the unachieved savings. In resolving the issue, the Commission stated:

> As discussed above, any forecast of costs and benefits that goes out far into the future is subject to great uncertainty. We approve the settlement agreement based on the best available current information, but many of the rates and programs assumed for the purposes of the business case have not been adopted by the Commission, and must ultimately be considered on their merits when specific proposals are made. Similarly, we have used the best available estimates for program participation in the business case analysis, but because CPP and PTR rates are not currently in widespread use for residential customers in California, these estimates, too, are subject to uncertainty. Future information on customer behavior in response to these or other dynamic rates may provide more accurate information on participation rates and demand elasticities, but we must analyze the settlement agreement based on the information available today. For these reasons, it is not reasonable to penalize SCE for failing to meet the forecasts made in the business case.
>
> It is, however, reasonable and desirable to determine how closely the demand response, conservation, and load control forecasts, and forecasts of associated benefits, match the forecasts made here. The collection of data the actual demand response achieved with the AMI system will provide us with valuable information on customer behavior, and enable us to track progress towards state energy policy goals associated with AMI, DR, and related issues. For this reason, in addition to approving the settlement agreement, we require SCE to report to the Commission on the energy savings and associated financial benefits of all DR, load control, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers. SCE should work with Energy Division develop a reporting format for this information, and should file annual reports in April of each year in R.07-01-041 or a successor proceeding until April 2019. If no successor proceeding exists, SCE should send these reports to the Director of the Energy Division and serve the service list of the most

> recent Commission demand response rulemaking. To the extent possible, SCE shall base its estimates of energy savings on the Commission's adopted load impact protocols contained in D.08-04-050 or successor protocols adopted in the future.[96]

The reasons expressed by the Commission for rejecting TURN's penalty proposal in SCE's AMI proceeding are applicable here. We have reviewed the record in this proceeding and have adopted what we consider reasonable estimates based on that record. It would not be appropriate to penalize PG&E, if the adopted demand response does not materialize.

Similar to what was required for SCE in D.08-09-039, PG&E should report to the Commission on the energy savings and associated financial benefits of all DR, load control, energy efficiency, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers. If not already included, these requirements are supplemental to the PG&E's reporting requirements mandated by D.06-07-027. PG&E may request recovery for the cost of this reporting requirement in appropriate cases.[97]

10.4. PG&E's Proposed Title 24 PCT Program for Residential Customers

In its December 12, 2007 application testimony PG&E indicated that new Title 24 building code air conditioning standards were expected in 2009. The new standards would require all new homes and retrofits requiring building permits for central air conditioning and heating to have Title 24 compliant PCTs

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[96] D.08-09-039, pp. 52-54.

[97] If PG&E requests such recovery, it must fully justify the costs and the incremental nature of the costs.

installed. PG&E would then target residential customers with the new PCTs for participation in PG&E's SmartAC Program. PG&E would also create a program to encourage existing air conditioning customers to initiate early retrofit of their standard thermostat with Title 24 compliant PCTs. However, the CEC withdrew its Title 24 building code air conditioning standards recommendation shortly after PG&E filed the application. PG&E now assumes the standard will be implemented in 2012 and that PG&E will begin recruiting new construction and permitted replacement/retrofit customers in 2013. PG&E states that all of these customers will be seamlessly integrated into PG&E's existing SmartAC Program, although the temperature set points, event notifications, and the ability for customers to override events will be communicated through the HAN gateway.

Under PG&E's proposal, PG&E's existing SmartAC Program will continue to operate as designed including the option as an enabling technology for a pricing program. All eligible SmartAC customers will be able to enhance their participation in CPP or PTR with the enabling technology provided on the SmartAC Program, including those joining the program through the proposed Title 24 PCT program. PG&E will offer to adjust participating customer air conditioning on the event days.

The Title 24 PCT program assumes the SmartAC Program will continue, but IT costs associated with the implementation via the HAN gateway device and using internal customer tracking systems are included by PG&E in this proceeding. Additional assumptions by PG&E include:

- All new residential construction with AC would have a Title 24 compliant PCT installed (based on the Residential Appliance

Saturation Study (RASS),[98] 75.5% of new homes are assumed to have AC);[99]

- 38,000 or 38% of the expected number of 100,000 major home remodels assumed to have AC (based on the RASS);

- Only 70% of heating, ventilation and air conditioning (HVAC) replacements or retrofits would be done with building permits, and that only the permitted retrofits would have Title 24 compliant PCTs installed;

- 25% of residential customers with a Title 24 PCT will enroll in the program based on a $25 incentive and the opportunity to lower peak time energy usage and save money on critical event days;

- The average number of AC units per customer is 1.08 based on recent SmartAC Program experience;

- Average of 0.75 kW per PCT consistent with PG&E's existing SmartAC Program impact estimates;[100] and

- A 15-year life of the PCT.

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98 California Statewide Residential Appliance Saturation Study Update to Air Conditioning UECs Using 2004 Billing Data Final Report, prepared for California Energy Commission (400-04-010), KEMA-XENERGY, May 2006.

99 New construction annual population estimates are calculated by applying climate zone growth rates and population counts consistent with those included in A.05-06-028, PG&E-4, Table 2-4 and 2-5, p. 2-10.

100 PG&E states that consistent with the SmartAC impact estimates is the assumption the 30% of residential customers will also participate in a dynamic pricing option, and therefore the average technology impact of 1.1 kW is expected to eliminate double counting of demand benefits with CPP or PTR.

In addition, for the early retrofit of existing air conditioning systems with Title 24 compliant PCTs, PG&E will target 30,000 customers a year with an enrollment cap of 250,000 customers. Since PG&E's current SmartAC Program is approved for up to 305 MW of demand response, the Title 24 PCT benefits claimed for Upgrade are only for demand response MW amounts above the 305 MW level.

PG&E's Upgrade demand response benefits include reductions of 3,738 MWs from 2013 through 2030 for demand response from Title 24 PCTs. Using an avoided capacity cost of $85 per MW, PG&E calculates PVRR benefits of $129,401,000.

10.4.1. DRA's Position

DRA states that PG&E has already counted the participation of new customers in its SmartAC program and has thus excluded Title 24 PCT benefits from its cost effectiveness analysis of the Upgrade.

Also, DRA questions whether PG&E can "seamlessly integrate" the HAN functionality with its SmartAC program operation as it claims. DRA states that operating the SmartAC program through the HAN interface does not mean that PG&E can replace the 900 MHz paging system approved for its SmartAC program, and quotes the following from PG&E's Upgrade testimony:

> Separate communications systems are likely to be necessary due to the possibility that customer-owned equipment installed under the current SmartAC program may not be able to communicate with the new HAN network.[101]

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[101] PG&E, Exhibit 3, p. 4-4, footnote 2.

Consequently, DRA argues that PG&E may not be able to operate all AC units participating in its SmartAC program through the HAN interface.

DRA notes that, as approved in D.08-02-009, PG&E has a communication system to remotely control PCTs. To promote interoperability, the CEC also considered requiring the PCTs to incorporate "communication expansion ports," to allow for remote control of the PCTs via other communication systems, such as the 900 MHz paging system for which PG&E received ratepayer funding in D.08-02-009. According to DRA, even if the CEC were to revert to mandate Title 24 PCT in new construction, its focus on technological interoperability (which both DRA and PG&E have publicly supported) would likely persist. In DRA's opinion, the Upgrade would not add an incremental functionality to PG&E's existing demand-side management system, beyond what PG&E could already achieve with its functionality claims in the AC Cycling and the original AMI applications.

In response, regarding DRA's double counting argument, PG&E notes that DRA's witness acknowledged that the AC Cycling settlement provided for up to 400,000 devices to provide 305 MW of demand response, including additions to cover attrition to maintain 400,000 devices in the program.[102] PG&E also indicates that its testimony also recognized that the A/C settlement was to install 305 MW of dispatchable demand response from 2007- 2011, with a cost/benefit analysis for the 15-year life of the program technologies. However, PG&E asserts that CAC cycling beyond the A/C settlement scope is needed to address increased demand from new construction over the Upgrade period. According

[102] DRA, Lee, 5 RT 718-719, 723.

to PG&E, its Upgrade cost/benefit analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement.

Regarding DRA claims that technological interoperability issues with Title 24 PCTs may interfere with PG&E's ability to operate AC units through the HAN interface, PG&E notes, as did DRA, that the CEC has considered requiring the PCTs to incorporate other communication systems. PG&E states that industry participants certainly are promoting HAN communication to CEC staff for this purpose, and the fact that the two southern California investor-owned electric utilities will have HAN systems, plus PG&E if the Commission approves this application, may move the market, making HAN communication a sensible element of Title 24 PCTs.

10.4.2. TURN's Position

TURN states that the PCT devices should be attributed zero benefits in this application, because PCTs are not incremental to the hardware requested in this application. PG&E already has a SmartAC program involving PCTs that can achieve demand response without the necessity to approve this application.

Also, TURN asserts that PCT demand response will be significantly less than anticipated by PG&E for the following reasons:

- Although PG&E assumes that PCT program participants will save on average 0.75 kW per hour per event, data from PG&E's 2007 SmartAC program (which offers either a one-way communicating PCT or AC cycler) predicts only a 0.48 KW impact for PCTs.

- Based on data from a ramping strategy that sets back the thermostat by 4° at the beginning of the event period, evidence from DOE modeling shows that a residential thermostat's impact on savings goes from 0.42 kW/ton in the first hour (2:00 p.m.) down to 0.25 kW in the fourth hour (6:00 p.m.). There is a snapback or rebound effect after the event ceases and the AC unit attempts to recover to its normal temperature setting. The full impact of the demand response does not last for four hours, as would be required for most resources that comply with resource adequacy (RA) requirements.

PCTs measured in PG&E's 2007 SmartAC program also sometimes showed a reduction in savings in the last hour. As shown in Ex. 206, p. 5-36, Figure 5-3 shows lower per-unit average kW reduction in the last hour in three of the six scenarios examined (two ramping strategies, three days each).

- Evidence from marketing surveys as well as marketing efforts supports a conclusion that it will be difficult for PG&E to achieve 25 % participation of PCT owners to receive temperature setbacks under its PCT program.

  TURN cites the 3.6% response rate from a marketing solicitation, stating that this result gives little confidence that PG&E would obtain 25% market penetration for its PCT program. TURN asserts that this is a long way from 25%.

  TURN also cites Greenberg research as evidence that PG&E would have difficulty reaching 25% participation. That research shows that customers with newer systems were negative about direct load control, feeling their equipment installation was a significant enough contribution to the energy shortage. TURN argues that the fact that the PCT is installed does not address at all the customer's reluctance to have it activated and to participate with temperature setbacks in the PCT program.

- For the 30,000 customers per year expected to voluntarily purchase PCTs and enroll in PG&E's PCT program, TURN states that the retail cost of the PCT device could be a barrier to participation. TURN states that PG&E did not provide an estimate of the cost of a two-way communicating PCT, and TURN calculated an estimate of between $90 and $120.

Also, TURN cautions that, in the event that the CEC does mandate PCTs, the cost to the homeowner of such a mandate will need to be offset with the benefit, e.g., the savings due to demand reduction. According to TURN, under this scenario PG&E cannot also count the value of the same demand reduction, as that would be double counting one benefit against two sets of costs in two different proceedings. TURN further states that PG&E's own assumption of only 25% of PCT customers actually participating in the demand reduction program lowers the likelihood that such a PCT mandate could even be cost-effective at the CEC.

TURN points out that alternatively PG&E could assume that no Title 24 mandate occurs, and include in the Upgrade project both the cost of a PCT as well as the benefit of the PCT demand reduction. This is the approach taken by SCE in its recent AMI proceeding (A.07-07-026), where SCE included a $50 charge for a PCT (in case there is no Title 24 mandate) and also included the benefit of the PCT demand response. PG&E states that, in the Upgrade, PG&E has not included a cost for the PCT as SCE did, and thus inclusion of the PCT DR benefit is not legitimate.

TURN asserts that its evidence justifies the following recommendations:

- The "Title 24" MW should be zero, even if PCTs are mandated elsewhere. A device could only be mandated if it were considered cost effective by the mandating agency, in which case the "benefit" of demand reduction will double count what PG&E proposes here. Otherwise the same benefit will be used to justify two sets of costs in two different venues. This reduces PG&E's projection by 40 MW in 2015 and 154 MW in 2025.

- For voluntary PCTs (PG&E's "non-construction" category), TURN expects the MW to be reduced by 33%, based on recent Smart AC evidence. This reduces PG&E's projection by 11 MW in 2015 and 41 MW in 2025. The cost of the PCT device, purchased by the customer, would need to be included in the TRC test. The high cost of a PCT device, relative to what PG&E proposes as an incentive to join the program, also causes TURN to doubt PG&E's projection for participation, although TURN has not imposed a separate adjustment for that factor.

Thus, for the years through 2030, TURN's projections are roughly 28%-37% of the annual PCT MWs that PG&E projects.

In response, regarding TURN's statement that the PCTs are not incremental to the "hardware" requested in the Upgrade case adding "PG&E already has a SmartAC program involving PCTs that can achieve demand response," PG&E states that TURN's later statement is not true for the Title 24 PCTs, as discussed in PG&E's response to DRA. As to the first statement, PG&E argues that TURN misses the point by asserting that PCTs should somehow be incremental to Upgrade equipment. According to PG&E, what matters is the Upgrade equipment's functionality with Title 24 PCTs. PG&E anticipates that the additional HAN functionality will be used with PCTs in the future for operation of CAC cycling during events for all three California investor owned electric utilities; and it is HAN's functionality that facilitates demand response with Title 24 PCTs which supports inclusion of the PCT benefits in this case.

In response to TURN's assertion that PCT demand response will be significantly less than anticipated by PG&E, PG&E provided the following reasons for rejecting TURN's analysis:

- Regarding TURN's attack on PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, PG&E indicates that the KEMA study referenced by TURN analyzed performance during the first summer of PG&E's A/C cycling program (2007) with 5,000 customers in the Stockton area. Differences between the demand reductions produced by switches versus PCTs were recorded, but those differences were primarily driven by how the program was operated, not by technology. PG&E witness Alexander reported that there were two ramping strategies with PCTs, both designed to overcome limitations of a single set point increase at the beginning of an event. Those strategies did not achieve the same load impacts as with switches. There are additional strategies that will be used in 2008. PG&E witness Alexander expects future ramping strategies and greater experience will lead to PCT load reductions comparable to switches. PG&E argues that it is not reasonable to discount potential PCT benefits based solely on the results of the limited operations of the startup program in a compact geographic area.

- With regard to TURN's questions of whether the demand response benefits from PCTs will last for four hours, PG&E states that TURN used a figure from PIER Buildings Program SCE Codes & Standards Program Workshop held early in 2006 to illustrate a steep drop in PCT impact near the end of the fourth hour. However, that table is the product of a DOE 2.2 model simulation, where the program is told to end by 6:00 p.m. Hence, according to PG&E, the model should be expected to produce a sharp drop in its simulated demand response by 6:00 p.m.

  In response to TURN's statement regarding RA requirements, PG&E notes that demand response can count for RA if it is available for 48 hours per summer, or qualify as a two-hour resource if not more than 0.89% of the RA need. In effect PG&E is reserving the right for the PCT (and possibly other DR programs under consideration here) to provide a smaller value to ratepayers (only two hours rather than four hours per day). However PG&E states it has made no showing that the PCT program is the only two-hour resource that the company will consider, and that the 0.89% of capacity from two-hour resources is not already oversubscribed (in which case the RA value of two-hour PCT savings would be zero)

While TURN refers to Figure 5-3 in the KEMA report for the proposition that PCT demand response drops off, PG&E points out that what the KEMA report really shows is a positive relationship between the temperature and the demand reduction for PCTs, as well as the program in general, based on summer 2007 data. Moreover, according to PG&E, KEMA's analysis of the summer 2007 data found no statistical difference between the PCT drop-off and the switches. (Reporter's Transcript, p. 221, lines 5-18.)

- Regarding TURN's attack on PG&E's 25% participation assumption, PG&E states that the KEMA process evaluation cited by TURN was performed at the program's infancy, when participation had yet to reach 5,000. However, in less than a year, the program has grown to over 75,000 customers with the $25 incentive, and PG&E indicates that is well on its way to achieving the 25% market penetration target.

  In addition, PG&E states that TURN's use of the Rate Option Positioning Research performed by Greenberg Brand Strategy in 2007 (Greenberg study) is inapplicable for Title 24 PCTs. The statement from the Greenberg study referenced by TURN reports that focus group participants with newer air conditioning systems were negative about changing equipment they had just installed. According to PG&E, this point is irrelevant for Title 24 PCTs required for new construction and permitted retrofits, because the PCTs would already be installed to comply with state building code standards. That code standard would neutralize the issue over time, and would help with several other customer concerns.

Regarding TURN's double counting argument related to how the CEC might conduct future analysis for new initiatives within its jurisdiction, PG&E states it is speculative and indicates that the CEC analysis TURN cites was done several years ago and includes assumptions of questionable relevance now. Also, PG&E states the CEC will have a number of input options that are not used in the Total Resource Cost (TRC) test at the Commission. For instance, the CEC might include customer bill savings and incentives from DR or rate programs in its analysis, although they are not part of a TRC analysis at this Commission. PG&E concludes that, since the CEC does things its own way, there is no way to know today what a future CEC analysis will depend upon.

10.4.3. Discussion

The threshold issue is whether or not to include PCT benefits in the cost effective analysis for the Upgrade. PG&E has produced evidence from which it can be concluded that its cost effectiveness analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement. We do not see double counting as alleged by DRA.

Also, we are not convinced by TURN's double counting argument involving future CEC actions. TURN has not listed the costs that would or might be assumed in such CEC actions that would need to be compared to a benefit such as demand reduction, and we do not know what they would be. There is also no evidence as to what the magnitude of those costs might be. Therefore, we have no way of knowing whether or not any future CEC assumed costs would significantly affect the cost benefit analysis as it applies to the Upgrade. We can only conduct our analyses with the information available and take factors such as CEC actions into account when they are known and relevant. It would therefore not be appropriate to completely dismiss the use of Title 24 PCT benefits in the Upgrade cost effectiveness analysis, as proposed by TURN.

For these reasons, we will include the PCT benefits in the Upgrade cost effectiveness analysis. However, while we will consider Title 24 PCT benefits as proposed by PG&E, we do agree with TURN that PG&E's estimates of MW savings may be excessive.

First, there is no certainty that the Title 24 regulations will be implemented in 2012, if ever. While PG&E assumes that date, there is no real evidence to substantiate it. There apparently was significant opposition to the regulation to the extent that it was eventually withdrawn. Whether such opposition can be overcome either in the short term or the long term is uncertain in our minds. If new construction and permitted retrofits are excluded from the benefit analysis for any length of time beyond 2012, the benefits will be reduced significantly.[103] PG&E projects some voluntary participants for this program. Whether the amount of voluntary participation will grow, if the Title 24 PCT regulations are not enacted, is uncertain.

There is also some uncertainty as to whether technological interoperability issues with Title 24 PCTs may interfere with PG&E's ability to operate AC units through the HAN interface.[104]

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103 As TURN indicates this issue was not as critical in evaluating SCE's AMI proposal, because SCE included both the cost of a PCT as well as the benefit of the PCT in its PCT demand reduction analysis. PG&E does not provide for the cost of the PCT, although it does provide a $25 rebate for this program.

104 In its Comments on the Proposed Decision of ALJ Fukutome, DRA noted the recent CEC Draft Committee Report on Proposed Load Management Standards, dated November 2008. In that report, the CEC proposed that communication of DR events with DR enabling technology be communicated through a Radio Data System and via the internet. In reply comments, PG&E states that in comments posted on the CEC website, PG&E and other utilities have identified major problems with the draft technical standard, and the Draft Technical Report recognizes the importance of the utilities' AMI systems that meet the CPUC's minimum functionality requirements to meeting the CEC's goals.

Regarding PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, PG&E gives a reasonable explanation of why 0.48 KW/hour savings may be low but provides no convincing evidence to justify its assertion that different ramping strategies will necessarily result in 0.75 kW/hour savings.

Whether PG&E's 25% market penetration rate will be reached is debatable. PG&E states that participation has grown to over 75,000 customers with the $25 incentive, and indicates that is well on its way to achieving the 25% market penetration target, but does not indicate where it is now and how much further it needs to go to meet the target.

We accept PG&E's explanations related to PCT duration and RA credits, but TURN's proposed reduction in PCT demand response due to the cost of the PCT for voluntary participants has some merit. PG&E has produced no estimate of what a PCT device would cost, while TURN estimates costs to be in the range of $90 to $120, which is significantly higher than the $25 rebate.

Given the above discussion, it is reasonable to reduce PG&E's forecasted benefits for the Title 24 PCT program by some amount. However, the state of the evidentiary record does not facilitate the quantification of what that amount should be. Demand response benefits are difficult to quantify because they depend substantially on future customer behavior to changed circumstances. Parties can speculate on what that behavior might be based on limited studies or theories but what will actually happen is far from certain. For these reasons, we will instead split the difference between TURN's estimate of Title 24 PCT program benefits and that of PG&E. We calculate that amount to be a PVRR of $83,427,000 as opposed to PG&E's estimate of $129,401,000.

11. Adopted Incremental Costs and Benefits

Table 3
Adopted Estimates of Incremental Costs

	Incremental Costs Nominal (Dollars in thousands)	Incremental Costs PVRR (Dollars in thousands)
Deployment Costs		
Meter Devices (Less HAN and Electromechanical Meter Upgrades)	$ 310,757	$ 486,358
HAN Retrofit	26,532	24,581
Electromechanical Meter Retrofit	18,800	20,372
Information Technology	33,600	49,793
Title 24 Program Costs	-	26,174
Peak Time Rebate Program Costs	-	27,592
Project Management	-	-
Training	1,697	1,592
Risk Based Allowance	44,139	46,724
Subtotal	$ 435,525	$ 683,186
Operations and Maintenance Costs		
Operations and Maintenance	$ 4,993	$ 42,886
Risk Based Allowance	562	503
Subtotal	$ 5,555	$ 43,389
Other Costs		
Technology Assessment	$ 21,400	$ 18,995
Risk Based Allowance	4,280	3,445
Subtotal	$ 25,680	$ 22,440
Total Incremental Costs	$ 466,760	$ 749,015

Table 4
Adopted Estimates of Incremental Benefits

	Incremental Benefits Annualized (Dollars in thousands)	Incremental Benefits PVRR (Dollars in thousands)
Operational Benefits		
Integrated Connect/Disconnect Switches		
Avoided Field Visits	$ (6,682)	$ (114,702)
Improved Cash Flow	(969)	(11,174)
Reduced Bad Debt	(2,429)	(26,756)
Tax Benefit from Meter Replacement	n/a	(11,799)
Subtotal	$ (10,080)	$ (164,431)
Energy Conservation/Demand Response Benefits		
Electric Conservation	n/a	$ (268,847)
Gas Conservation	n/a	0
Peak Time Rebate	n/a	(262,916)
A/C Cycling	n/a	(83,427)
Subtotal	n/a	$ (615,190)
Total Benefits	n/a	$ (779,621)

11.1. Conclusion

The adopted costs and benefits result in a PVRR net benefit of $(30,606,000). By this adopted analysis, the Upgrade is cost effective. However, we note that, when compared to the total Upgrade incremental PVRR cost of $749,015,000, that net benefit is small (only 4.1%). It is insignificant when considering the uncertainties in estimating the PVRR of the Upgrade costs and benefits, especially the conservation and demand response benefits. Changes in only a few assumptions could make the Upgrade cost ineffective or substantially more cost effective. Despite the narrow margin of cost effectiveness reflected in this decision, we feel it is reasonable to authorize PG&E to proceed with the proposed SmartMeter Upgrade, subject to the conditions and costs specified in this decision and will do so. Our judgment is influenced by the results of the cost effectiveness analysis and following additional factors:

- In PG&E's original AMI proceeding, benefits exceeded costs by $104.4 million (4.6%). When looked at on a total basis, it is even more likely that the ratepayers will not be harmed by implementing the Upgrade.

- As described previously by PG&E, on a total basis, the SmartMeter Program compares favorably with what was authorized for SCE and SDG&E. While our adjustments to PG&E's estimates may make that comparison less favorable, it is worthwhile to note that PG&E's costs and cost effectiveness are still in the range of the other two IOUs.

- Authorizing the Upgrade results in a common statewide technology platform for the three IOUs. In general, reasonable consistencies in system components and functionality will facilitate the implementation of consistent demand response and conservation programs, which is desirable.

- The upgraded technology will provide for a technology platform that offers common functionality for PG&E customers, for utility program offerings, and for vendor development of tools, applications, and the expanding market for home energy management devices. Consistency in the marketplace will provide vendors a common set of functionality against which to develop interoperable products that adhere to common standards.

- It is likely that there are other benefits that have not been quantified by PG&E or other benefits that can be realized through the upgrade technology that may arise in the future.

12. Cost Recovery

12.1. General Proposal

Regarding cost recovery of the Upgrade, PG&E proposes the following ratemaking treatment:

- Rates will be set initially to recover forecasted project costs, including the incremental costs and benefits of the SmartMeter Program Upgrade; with true-up to actual costs achieved through the existing SmartMeter Balancing Account – Electric (SBA-E).

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

- Costs associated with the SmartMeter Program Upgrade incurred prior to a Commission decision of this application and recorded in a memorandum account, upon approval of the advice letter filed concurrently with this application, will also be reviewed in this application, and as a result of that review, these incurred costs will be deemed reasonable and will be transferred to the SBA-E for recovery.

- Incremental benefits or cost reductions will also be reviewed in this proceeding, and specified pre-approved forecasted benefits will be incorporated into rates through the SBA-E as associated project milestones are met.

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

As ordered in D.06-07-027,[105] PG&E indicates that it will present testimony in its next GRC concerning the continuation of the balancing accounts as an alternative to traditional ratemaking treatment.

No party has challenged PG&E's general cost recovery proposal as described above. It is reasonable and will be adopted. However, parties have challenged certain aspects of PG&E's allocation methodology, as well as the benefits recognition proposal, as discussed below.

12.2. Generation/Distribution Allocation

PG&E proposes to recover the SmartMeter Program Upgrade costs from customers in the same manner as adopted in D.06-07-027 for other SmartMeter Program costs. That is, the total revenue requirement will be recovered in the same manner as other distribution revenue, based on the distribution revenue allocation and rate design methods authorized by the Commission at that time.

12.2.1. DRA's Position

Since PG&E justifies the Upgrade costs primarily on demand response and energy conservation benefits, DRA recommends that any Upgrade costs approved by the Commission be allocated by a generation allocator. According to DRA, savings due to peak load reduction and energy conservation typically flow through an energy resource recovery account, from which the account balance automatically flows to customer classes based on a generation allocator. This means that, if the potential benefits of the Upgrade do occur, the energy saving benefits would flow back to customer classes accordingly. For the residential class, the generation allocator is approximately 40.6%. DRA argues

[105] D.06-07-027, Ordering Paragraph 15.

that, as the residential class would obtain 40.6% of potential benefits, it makes sense that they also pay 40.6% of the costs. According to DRA, PG&E's proposal to allocate AMI Upgrade costs by a distribution allocator would allocate 55.1% of these costs to the residential class. DRA states that PG&E is thus recommending that residential customers pay far more than they would potentially benefit from the Upgrade. DRA instead recommends that the Commission allocate any approved Upgrade costs by generation allocators that would allocate approximately 40.6% of these costs to the residential class.

In response, PG&E states that DRA's proposal is inconsistent with established practices of cost allocation. PG&E notes that DRA acknowledges PG&E's proposal follows the method already being used to recover those costs authorized by PG&E's Original AMI Case. PG&E also notes that its proposal is consistent with the method adopted by the Commission in SDG&E's recent AMI case, as well as DRA's settlement with SCE on its recent AMI case.[106] Furthermore, PG&E is not aware of any cases where distribution infrastructure costs have been allocated on a method other than to distribution-level EPMC.

12.2.2. Discussion

At this point, we will continue the use of the allocation methodology that applies to PG&E's original AMI authorization. In general, it is reasonable to allocate distribution infrastructure with distribution level EPMC related allocators, and PG&E's methodology is consistent with how SDG&E's AMI related costs are allocated. We will not preclude DRA, or any other party, from raising the issue in PG&E's next Phase 2 GRC proceeding. In fact, that would be

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[106] The SCE AMI settlement defers consideration of the allocation methodology to SCE's GRC, and uses a distribution allocation for any interim period.

a more appropriate forum for proposing such an allocation methodology that is based on principles which differ significantly from existing principles.[107]

12.3. Streetlight Allocation

CAL-SLA argues that PG&E does not need a meter to determine street light energy usage.[108] According to CAL-SLA, PG&E already has more than sufficient information to determine annual energy usage from streetlights, so a meter would be surplus. CAL-SLA also notes that while some other customers might use the SmartMeter to alter their energy usage pattern, it is not the case with street lights, since they only operate at night.

CAL-SLA's policy position is, since SmartMeters will not be installed on street lights because they are unnecessary, street light customers should not pay for SmartMeters. CAL-SLA points out that it has never contended that street light facility charges which are unique to street lights should be assessed against all other customers.

PG&E disagrees with CAL-SLA's position for the following two reasons. First, it is at odds with the Phase 2 GRC Settlement, of which CAL-SLA was a signatory. Second, CAL-SLA's position ignores the benefits that would accrue to streetlights customers from the Upgrade. According to PG&E, street light customers will receive benefits as a result of many of the improved operating efficiencies that will benefit all customer classes, such as reduced labor costs and improved cash flows. PG&E also notes that street light customers will benefit

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[107] In this proceeding, the record on this issue is limited. Viewing it in the context of all of PG&E costs would provide a venue for considering all costs and applying the proposed principles in a consistent manner across all costs, if adopted.

from the new peak load management efforts and energy conservation efforts that should result in lower overall generation and distribution revenue requirements.

12.4. Discussion

In addressing this issue, we agree in general with PG&E's position that, while street light customers will not receive any benefits directly associated with having an upgraded meter, there are likely to be some benefits to street light customers due to the Upgrade, in the form of increased operational efficiencies and reduced revenue requirements. For this reason, it is reasonable to allocate some amount of the Upgrade costs to street light customers. We also feel it is reasonable to use the settlement in PG&E's last rate design settlement to do so.

In its testimony, CAL-SLA states the following:[109]

> PG&E states that in Exhibit C, Table 1, the revenue allocation methodology is to allocate distribution revenue to each class based on each class' total share of present distribution revenue. For the street light class, revenue from facilities charges is included in distribution revenue used for the basis of the allocation. The inclusion of facilities charges causes the percentage increase for the street light class to be higher than for other classes and the systemwide percentage change.
>
> PG&E goes on to state that the revenue allocation methodology used in the SMU application is not what was approved in D.07-09-004 in Phase 2 of the utility's 2007 Test Year General Rate Case.
>
> CAL-SLA recommends that the Commission use the revenue allocation methodology adopted in the Phase 2 GRC D.07-09-004.

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108 According to CAL-SLA, out of the approximate 45,000 streetlight accounts taking service from PG&E, 1,000 are metered under Schedule LSD-3.

109 Exhibit 301, p. 8.

> Street light facilities charges should be treated as non-allocated revenues and therefore excluded from revenue allocation. Under the Phase 2 revenue allocation, street light's increase would be reduced from 1.7% to 0.5%.

The use of the Phase 2 GRC decision revenue allocation methodology for allocating the Upgrade revenue increase is apparently a secondary recommendation of CAL-SLA, whereby the street light customers' increase would be reduced when compared to PG&E's proposal for the Upgrade. In rebuttal testimony, PG&E states, "Yes. PG&E agrees that D.07-09-004, as issued in Phase 2 of PG&E's 2007 GRC, sets forth the appropriate methods for changing rates that may result from a change in revenue requirements to recover the costs of the Upgrade project."[110]

There were a number of settlements in Phase 2 of PG&E's 2007 GRC, which addressed marginal costs, revenue allocation and rate design. In the particular settlement on marginal costs and revenue allocation,[111] Section VII.3 addresses rate changes between GRCs. The Upgrade will result in a rate change between GRCs, so it is appropriate that the Section VII.3 principles in the marginal cost and revenue allocation settlement should be followed in determining the allocation of Upgrade costs to the various customer classes. PG&E should allocate the Upgrade revenue increases accordingly.

CAL-SLA indicates that its primary recommendation does not comport with the Phase 2 GRC settlement but adds that SmartMeters were never identified in that proceeding as a cost to be allocated to street lights.

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110 Exhibit 8, p. 5-3.

111 *See* D.07-09-004, Appendix B.

We do not know what was assumed by the settling parties, including CAL-SLA, when the marginal cost and revenue allocation settlement agreement was reached. Settlements generally represent a compromise among the Settling Parties' respective litigation positions, in order to agree on a mutually acceptable outcome. What may not seem to be fair, when viewing a portion of the settlement in isolation, may be fair, when viewing the settlement in its entirety. We can only judge issues such as this by the plain language of the settlement. Authorization of the Upgrade necessitates a rate change between GRCs. The settlement provides principles for rate changes between GRCs. There is nothing in that section of the settlement that limits the application of those principles, if the increase is driven by SmartMeter costs or any other specific costs. There is nothing that states that certain customers can avoid an increase, if the reason for that increase does not directly benefit those customers. In order to honor the settlement process, we have no alternative but to impose the principles for rate changes between GRCs, as identified in PG&E's TY 2007 Phase 2 marginal cost and revenue allocation settlement, in allocating the Upgrade related revenues to customer classes. In doing so, street light customers will receive an allocation of Upgrade costs, although that allocation will be substantially lower than what was originally proposed by PG&E.

By our determination today, we are not precluding CAL-SLA or any other party from raising the issue of how SmartMeter costs should be allocated in PG&E's next Phase 2 GRC proceeding. We expect such an issue would necessitate a fairly comprehensive analysis of what types of costs, beyond just SmartMeter costs, directly benefit or do not directly benefit the various customer classes and which of those costs should be assigned to particular customer classes.

12.5. Benefits Recognition

PG&E proposes to continue the current mechanism for recognizing benefits resulting from the Upgrade on a monthly basis as meters are activated and project milestones are achieved. Specifically, once the remote connect/disconnect functionality has been activated (expected in the latter half of 2009), PG&E would adjust the existing per electric meter monthly benefits calculation from $1.7722 per active electric meter per month by an additional $0.1821 per active electric meter per month, to be in effect through the end of 2010. Starting with 2011, these amounts would be subject to revision through PG&E's GRC or other applicable regulatory mechanisms. DRA and TURN dispute the timing of PG&E's benefits recognition proposal.

12.5.1. DRA's Proposal

DRA recommends that PG&E track and report the differences between the AMI benefits actually credited to ratepayers and those shown in PG&E's business cases, for both the original and Upgrade applications. DRA recommends that PG&E should automatically credit ratepayers with the benefits of both the original and Upgrade projects eight months after meter costs enter into the rate base. This will ensure that ratepayer benefits are not delayed due to further deployment delays. According to DRA, continuing the benefits recognition proposal adopted in the original AMI decision unfairly allocates a disproportionate share of the financial risks to ratepayers.

PG&E states that adhering to DRA's proposed timeline would reduce PG&E's incentive and flexibility to actively manage and reduce project costs. For instance, PG&E indicates that its management currently has incentives to take advantage of volume discounts for purchasing materials during a certain period of time, and for taking advantage of tax rules that can provide benefits from accelerating the purchase of items during a certain tax year. In order to take advantage of these discounts, PG&E may need to buy items in advance of what would be needed for the deployment schedule. A mandate to begin crediting customers eight months from the booking of such costs into rate base would provide a disincentive to PG&E from taking advantage of these discounts, resulting in higher project costs. PG&E indicates this would also increase the administrative burden and therefore the cost of running the project. Hence, PG&E believes that it would be prudent to adhere to the current benefits recognition method under which PG&E commences recording benefits only after the meter is activated.

12.5.2. TURN's Proposal

TURN states that PG&E's AMI pre-deployment and AMI deployment funding requests were both authorized, in large part, because the tangible operational cost savings flowing back to ratepayers were supposed to pay for approximately 90% of the project costs; and PG&E is significantly behind in crediting ratepayers with the per-meter operational benefits that were included in PG&E's originally authorized AMI program. TURN asserts that because PG&E's AMI project is so far behind schedule, for both gas and electric meter deployment, as compared to the deployment forecast authorized in D.06-07-027, only negligible operational cost savings have been credited back to ratepayers to date (less than 18% of total costs). TURN therefore recommends that PG&E be directed to credit at least $44.8 million in operational benefits back to ratepayers as part of this proceeding.

It is TURN's position that, given that so few operational benefits are being provided as planned, combined with the time value of money where costs and benefits in earlier years are weighted more heavily than in the outer years, PG&E's original 90% operational cost-effectiveness will no longer be achievable unless the Commission orders a crediting back to ratepayers.

In response, PG&E provides three reasons why it believes TURN's proposal should be rejected.

First, according to PG&E, the values used by TURN to calculate the level of expected benefits were forecast estimates and never meant to be—nor did they become—required targets set by the Commission. TURN's recommendation to, in essence, require PG&E to record benefits in accordance with such a schedule is contrary to the method adopted by the Commission in D.06-07-027. That method requires PG&E to record in the balancing accounts revenue requirement costs and agreed-upon benefits only after meters are activated, not in accordance with some prescribed schedule. The Commission stated:

> We find PG&E's proposed balancing account mechanism, with a per meter benefit credit, to be reasonable because PG&E recovers its new AMI-related costs on an actual basis and it ensures ratepayer benefits are captured as meters are activated. (D.06-07-027, p. 51.)

PG&E notes that in adopting this mechanism, the Commission expressly rejected a competing ratemaking proposal from TURN that would have levelized costs and benefits according to a prescribed schedule somewhat analogous to that proposed here by TURN. The Commission rejected TURN's proposal stating that it was not persuaded by TURN "[T]hat such a method is reasonable for either ratepayers or shareholders."[112]

Second, PG&E states that TURN's argument ignores the fact that recorded costs have also trended behind the original forecasts; and while TURN argues

112 D.06-07-027, p. 54.

that benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule. PG&E argues that this "delay" in expenditures dwarfs the value of "delayed" benefits, a fact that benefits ratepayers under the ratemaking scheme adopted by D.06-07-027.

Third, PG&E states that TURN's argument ignores the fact that PG&E's current deployment schedule still reflects an overall completion timeframe of five years as per the original timeframes within the AMI case; and any "delay" in benefits or costs will be short-lived with project benefits accelerating during the later years of deployment.

12.5.3. Discussion

We see no compelling reason to change the benefit recognition procedures adopted in D.06-07-027 and will not adopt DRA's proposal. We recognize that DRA's proposal is similar to the benefit recognition procedure that was included in SCE's AMI decision. However, it is not clear from the record that, over the long term, the DRA proposal will be more beneficial to ratepayers. Consistency is important, but being consistent with the benefit recognition procedures previously found reasonable in D.06-07-020 is just as valid as being consistent with the settled procedure adopted for SCE. We have not been presented with evidence that suggests PG&E is mismanaging funds, and recognizing benefits when the meter is activated is reasonable, if only because no benefits can be realized until the meter is activated. Also, as PG&E indicates in responding to TURN, while benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule. For that reason, we do not see any harm to ratepayers by continuing the existing procedures.[113]

Also, PG&E's reasons for rejecting TURN's $44.8 million ratepayer credit proposal are persuasive, and we will not adopt that proposal.

13. Revenue Requirement

PG&E uses a results of operations model to compile all capital-related costs, operating expenses and benefits into an income statement format to estimate the additional amount of revenue needed to recover the cost of the Upgrade. PG&E has presented these forecasted revenues, or revenue requirement, for the following reasons:

- PG&E requests that initial rates for project deployment, to be effective January 1, 2009, be set based on the revenue requirements presented in its testimony, although ultimately PG&E proposes to recover actual costs of the project;

- PG&E also requests that SmartMeter Program Upgrade rates be changed on January 1 of 2010, based on the revenue requirement presented in its testimony, plus balancing account balances calculated at the time the rate change is requested;

- PG&E asks that the RO model assumptions and methods used to calculate the capital revenue requirements discussed in its testimony be approved for calculating monthly capital revenue requirements based on recorded SmartMeter Program Upgrade plant;

[113] While rates will be set initially to recover forecasted project costs, including the incremental costs and benefits of the SmartMeter Program Upgrade; a true-up to actual costs will be achieved through the existing SmartMeter Balancing Account.

- To show how the incremental costs presented in Exhibit 3 translate into revenue increases; and

- To provide forecasted revenue requirements for the calculation and evaluation of rate impacts.

PG&E's cost recovery proposal seeks to recover the entire costs of the SmartMeter Program Upgrade from customers. PG&E requests that the Commission approve the use of the revenue requirements set forth in its showing to establish rates.

No party has disputed the use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade. The use of the model for this purpose is reasonable, and it should be used to calculate the Upgrade revenue requirements, using the costs adopted by our decision today.

14. DRA's Water Utility Proposal

DRA proposes that PG&E's SmartMeter Program facilitate the automated meter reading (AMR) of its customers' water usage. It is DRA's belief that AMR provides cost savings mainly associated with water meter reading and assists as a tool to promote water conservation. According to DRA, facilitating water AMR is fairly easy to do at the meter endpoints. Also, the amount of additional information involved would not significantly tax the head-end hardware and software given that water meter reads generally only occur monthly. The largest issue is that of PG&E coordinating with the billing departments of various water utilities and providing billing data in an electronic form in a timely and secure manner.

DRA accepts that water metering benefits need not be part of this proceeding, but urges the Commission to order PG&E to try to incorporate this potential benefit into its long term deployment. DRA states that PG&E should hold workshops, as SCE has agreed to do in its AMI settlement, to explore issues related to AMI for water utilities.

14.1. CCSF's Position

CCSF interprets that the purpose of DRA's testimony regarding water metering appears to have been to recommend that the Commission should explore the possibility of using of using PG&E's AMI system for water metering in a separate proceeding and does not object to the recommendation. CCSF states, to the extent feasible, water and electric utilities should be cooperating and working together in the best interests of their common customers. Because CCSF's water utility is in the process of implementing its own AMI system, CCSF states it is willing to work with PG&E to avoid system redundancy. In the event the Commission should decide to hold workshops on this issue, CCSF recommends that the Commission first notify all water utilities and urge them to participate.

14.2. PG&E's Position

Consistent with DRA's recommendation, PG&E supports ongoing dialogue with water agencies and seeks the flexibility from the Commission to pursue these discussions through either multi-party workshops or direct dialogue with the water utilities. PG&E also states that, for the most part, CCSF echoes the recommendations of DRA and, to the extent CCSF does so, PG&E does not disagree with CCSF's testimony. However, PG&E states that it does disagree with the suggestion in CCSF's testimony that it may be cost-effective for PG&E to consider use of CCSF's possible automated water meter reading system.

PG&E indicates that it is highly unlikely that it would ever be cost-effective for PG&E to use a water utility's water meter reading system and cites the following cross-examination of DRA's witness:[114]

> CCSF Counsel: And are they -- the AMI systems being installed by these water companies, could they be used by PG&E instead of the water companies using PG&E's?
>
> DRA Witness Abbott: No. It would normally be the other way around. And the reason for that is that the electric metering application is very data-intensive. There's an awful lot of data processing. In this case we're talking about PG&E doing hourly metering. There's very few cases that I'm aware of in which any water utility would try to deal with hourly water metering at the residential level.

PG&E agrees with DRA on this and recommends that the Commission should not entertain CCSF's suggestion any further.

14.3. Discussion

DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory is reasonable and may result in additional benefits for the SmartMeter project. PG&E and CCSF support DRA on this, and we will order PG&E to work with the water utilities, either through multi-party workshops or direct dialogue with the water utilities.[115] We suggest that this should be done sooner rather than later and will require that PG&E report back on the status of its efforts and results of its discussions on a quarterly basis.

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[114] DRA, Abbott, 4 RT 495-496.

[115] PG&E should arrange and conduct the workshops similar to what is currently being done by SCE in addressing a similar requirement.

We understand PG&E's concerns regarding its use of a water utility's AMI system and suspect that it would be an unlikely occurrence, but we will not limit potential discussion and foreclose that possibility.

15. Procurement Diversity

PG&E's SmartMeter Program, including the Upgrade approved herein, is a substantial project that will involve significant procurement of goods and services. Accordingly, we remind PG&E that "it is the declared policy of the state to aid the interests of women, minority, and disabled veteran business enterprises in order to preserve reasonable and just prices and a free competitive enterprise, to ensure that a fair proportion of the total purchases and contracts or subcontracts for commodities, supplies, technology, property, and services for regulated public utilities are awarded to women, minority, and disabled veteran business enterprises, and to maintain and strengthen the overall economy of the state."[116] Furthermore, General Order 156 requires certain utilities, including PG&E, "to submit annual detailed and verifiable plans for increasing women, minority and disabled veteran business enterprises' (WMDVBE) procurement in all categories."[117] We expect PG&E to comply with the spirit as well as the letter of General Order 156 in the course of carrying out the activities related to the Upgrade approved herein.

16. DRA Motion to Reopen the Record

On February 17, 2009, DRA filed a motion to set aside submission and reopen the record for the taking of additional evidence in this proceeding. DRA requests that Attachment A to a February 10, 2009 PG&E Ex Parte Notice

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[116] Public Utilities Code Section 8281(a)

[117] General Order 156, "Rules Governing the Development of Programs to Increase Participation of Women, Minority and Disabled Veteran Business Enterprises in Procurement of Contracts from Utilities as Required by Public Utilities Code Sections 8281-8286", current as of August 24, 2006, Rule 1.1.1.

(Attachment A) be introduced into the record as an indication that substantially fewer meters, when compared to the 288,000 meters forecasted by PG&E in this proceeding, were actually deployed before HAN gateway devices became available to PG&E. Once this document is entered into the record, DRA requests that, if the Commission decides against DRA to fund the retrofit, funding should be limited to the cost of retrofitting the actual number of meters that were installed in 2008 rather than PG&E's forecasted numbers.

On February 18, 2009, PG&E responded to DRA's motion. PG&E indicates its opposition, arguing that DRA has not satisfied its burden in justifying its request[118] and DRA's interpretation of the data in the Ex Parte Notice is fundamentally flawed. PG&E states that the final decision is already two months delayed beyond the schedule originally adopted for this case, and PG&E is at risk for Upgrade costs already incurred. If the record is reopened and the matter delayed, PG&E states that its costs and financial risk would be proportionately higher. PG&E also asserts that DRA's evaluation of the information contained in Attachment A contains errors and fails the high standard imposed by the Commission for reopening the record. According to PG&E, DRA misrepresents the number of meters that will require a HAN retrofit, and PG&E will actually end up spending more than its forecasted amount of $32 million to maintain the benefit stream for customers. To the

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118 According to PG&E, in a case addressing a request to reopen a proceeding under Public Utilities Code Section 1708, the Commission explained:

"The burden of demonstrating that reopening is justified is substantial. The showing required in any given case will necessarily depend on an assessment of the financial and other costs to the parties and the ratepayers should authority be suspended and a case

Footnote continued on next page

extent that DRA seeks an opportunity to reduce costs based on its interpretation of actual deployment data, PG&E argues that it should have an equal opportunity to correct DRA's arguments and provide evidence that shows actual deployment costs are higher than forecasted.

16.1. Discussion

DRA's motion to set aside submission and reopen the record for the taking of additional evidence in this proceeding is denied, as explained below

That the deployment of electric and gas meters might vary, not only from what was originally planned but from updated deployment plans as time goes by, is not unexpected. The manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of factors such as the availability of materials and equipment, the regulatory process, and changes in technology as the deployment of meters is progressing. We must authorize a reasonable projected meter deployment cost based on information known and analysis conducted at a certain point in time. From that point on, we expect PG&E to manage its plans and costs in a manner that results in successful implementation of the Upgrade at or near the authorized funding levels while maximizing ratepayer value.

DRA's Motion to Reopen the Record raises the issue of determining the appropriate point in time to cut off the use of more recent information and related analyses in deciding what costs to authorize for the Upgrade. Normally that cut off point would be when prepared testimony and rebuttal testimony have been issued. That evidence can be tested through the evidentiary hearing

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reopened, as well as an evaluation of the information submitted in support of the request." (Re Pacific Gas and Electric Co., 4 CPUC2d 139, 150 (1980).)

process and critiqued in post hearing briefs.[119] While under certain circumstances, it may well be appropriate to reopen the evidentiary record to consider more recent information and changed circumstances, this is not the case with respect to the more recent information contained in Attachment A.

As indicated by DRA, Exhibit 2 in Attachment A shows that during the second half of 2008 there was a significant reduction in the deployment of meters that will require a HAN retrofit when compared to the 288,000 such meters that were forecasted to be deployed during that timeframe in PG&E's May 14, 2008 testimony. However, there is additional information in Exhibit 2 in Attachment A that indicates, among other things, that (1) the total number of gas and electric meters that were actually deployed by the end of 2008 was greater than the total number of gas and electric meters forecasted to be deployed by the end of 2008 in PG&E's testimony; (2) the related benefits for the 2008 through 2010 time period were now forecasted to be larger based on the actual deployment, as opposed to the magnitude of benefits reflected in PG&E's testimony for that timeframe; and (3) the cost to maintain the benefit stream associated with the actual deployment of meters through February 10, 2009 is expected to be greater than the $32,032,000 in HAN retrofit costs reflected in PG&E's testimony.

It appears that PG&E has modified its meter deployment plan in response to changed circumstances. As explained above, such changes can be expected and may be reasonable. In this instance, it appears that there is a slight increase in benefits with the change. It also appears that the costs related to the changed plan, which includes costs to retrofit a reduced number of meters with HAN

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[119] In certain instances, such as in GRCs, update testimony and associated evidentiary hearings are provided for.

gateway devices and costs to accelerate the meter deployment schedule, among other things, will exceed the forecasted amount for the HAN retrofit that was contained in PG&E's testimony. That is, while the number of meters requiring a HAN retrofit has decreased, the revised deployment plan that reflects that reduction will actually cost more than the originally forecasted HAN retrofit.

At this point, we do not feel it is necessary to reopen the record for the taking of additional evidence. While there may be an indication that costs are being incurred in a different manner than anticipated in the process of deciding this matter, that indication in itself is not sufficient reason to reopen the record for this proceeding. For a project of this magnitude, we do not expect that any amount of evidence record will result in a forecast of costs that will be replicated by what is actually spent on a detailed cost category basis. As mentioned previously, the manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of changed circumstances. Also, when looked at in total, the Attachment A information does not support a significant cost decrease as requested by DRA. It, in fact, shows overall increased costs. However, if total projects costs were to go up as indicated in Attachment A, it would be appropriate to assume that the additional costs would be covered by the risk based allowance authorized by this decision. Under these circumstances, it would not be an efficient use of Commission resources to reopen the record to consider all aspects of the information contained in Attachment A, a process that might require additional evidentiary hearing and briefs.

17. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on January 16, 2009 by PG&E, DRA, TURN, CCSF and CAL-SLA. Reply comments were filed on January 22, 2009 by PG&E, DRA, and TURN

To the extent that comments merely reargued the parties' positions taken in their briefs, those comments have not been given any weight. The comments which focused on factual, technical, and legal errors have been considered, and, if appropriate, changes have been made.

17. Assignment of Proceeding

Rachelle B. Chong is the assigned Commissioner and David K. Fukutome is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Commission has already authorized deployment of the HAN gateway for both SDG&E and SCE, and to do for PG&E would ensure statewide consistency as long as their efforts are coordinated. Consistency is important in providing a basis on which the HAN technology can efficiently develop and for providing a large market force that can be influential in developing appropriate standards.

2. There is no evidentiary record on which to judge the merits of a stand-alone HAN gateway device.

3. The most cost effective way to provide HAN access through PG&E's meters, over the long term, would be through PG&E's meter deployment plan rather than through random retrofits.

4. The increased functionality of the integrated load limiting connect/disconnect switch could be used to implement certain demand response programs and to provide area-wide and system-wide relief during peak usage

periods that are in the public interest and are not available under PG&E's original AMI program.

5. The integrated load limiting connect/disconnect switch provides significant incremental operational benefits related to field technician labor savings for connect/disconnect services.

6. A number of new capabilities including a HAN gateway device (enabling price signals, load control and near real time data for residential electric customers) and load limiting disconnect switches, and potentially more features in the future, are possible because of the increased processing power, memory storage, programmability, and upgradeability provided by the solid state meter platform.

7. No party disputes the technological merits of the advanced solid state meter.

8. PG&E is not requesting additional funds for either its electric or gas communication networks.

9. Certain technologies, such as that related to communication networks, have evolved over the course of PG&E's SmartMeter project making them more cost effective to employ.

10. PG&E considers any costs and benefits related to its total AMI project (original plus Upgrade) that were not specifically included in the original AMI project cost/benefit analysis to be incremental for the purposes of justifying the cost effectiveness of the Upgrade.

11. DRA believes that Upgrade benefits that could have been achieved by the original AMI system that was approved by the Commission in D.06-07-027, should be excluded from the cost-effectiveness analysis for the Upgrade. TURN and CCSF support DRA's position.

12. The levels of conservation and demand response benefits PG&E claims in the Upgrade cannot be achieved without the further expenditures contained in the Upgrade.

13. DRA's definition of incremental is unduly restrictive in that it results in certain benefits not being recognized at all for cost effective purposes, either in PG&E's original AMI case or the Upgrade.

14. DRA's definition of incremental is essentially at odds with the manner in which the Commission evaluated the AMI requests of SDG&E and SCE.

15. The record in this proceeding is insufficient for determining the cost effectiveness of PG&E's SmartMeter program on a total basis (PG&E's original AMI plus the Upgrade).

16. The Upgrade will facilitate upgrades of both firmware and software and will enable PG&E to update both the functioning of the endpoint and initiate future programs without the necessity of visiting the endpoint. This aspect of the Upgrade should permit the current technology to perform capably well into the future even in the face of major advancements in technology.

17. PG&E's estimate of meter device costs is based on costs derived from an RFP process. Based on responses to that process, PG&E conducted an evaluation of the integrated meter devices from certain vendors to help identify vendor and meter device technologies best suited to serve PG&E and its customers.

18. Details regarding DRA's estimate of meter device costs is limited due to non-disclosure restrictions.

19. The HAN Retrofit involves PG&E deploying 288,000 upgraded meters with load limiting switches and upgrading these meters with HAN gateway devices at a later date.

20. The estimated 20-year life for endpoints is not relevant for purposes of analyzing the economic impact of a deployment scenario.

21. Costs incurred prior to the starting point of a comparative analysis (and recorded benefits) have no impact on the result of the HAN Retrofit comparative analysis, because they would be the same for all scenarios being compared.

22. PG&E's consultant's HAN retrofit suspension analysis was performed before the HAN retrofit aspect of meter deployment began, and was thus available for PG&E's project management to use in determining whether or not to go forward.

23. Despite the significant costs related to the HAN Retrofit, the evidence suggests that lost benefits, due to a meter deployment suspension until the HAN devices became available, would exceed the net reduced costs caused by the suspension.

24. PG&E has not fully supported and justified the magnitude of its HAN retrofit cost estimate.

25. Electromechanical meters have been deployed in the Kern region, and, as a result of PG&E's Upgrade request, the electromechanical meter costs will become stranded once these meters have been replaced.

26. In our analysis of PG&E's risk based allowance, we have determined that the stranded costs related to the electromechanical meters should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project.

27. The basis for DRA's proposal for a 30% use of the HomePlug or PLC technology stems from a hypothetical analysis involving cost sensitivity based on a 30% assumption. There is no evidence as to the reasonableness of using 30% to reflect what might actually occur.

28. The determination of who will use the HAN technology and to what extent they will use it is fairly subjective at this point.

29. HAN connectivity on a universal basis makes sense for such purposes as advancing and developing the HAN technology in an efficient manner.

30. It is PG&E's responsibility to achieve HAN connectivity in the most cost effective manner within the costs and risk based allowances provided by this decision.

31. In its supplemental testimony, PG&E indicates that it now expects to begin recruiting AC customers in 2013 and estimates the number of customers for that year to be 18 with increasing amounts thereafter.

32. Regarding IT costs associated with the Title 24 PCT program, PG&E has provided no specific reasons to justify why these costs need to be incurred prior to or in 2011 and why they cannot be shifted commensurate with when the expected recruitment of Title 24 PCT customers is expected to begin.

33. There is significant uncertainty as to when Title 24 PCT program will begin, and the program costs have already been moved by PG&E to 2013, outside the timeframe for cost recovery authorized by this decision.

34. The adoption of PG&E's IT proposal, as a means for addressing significant systems integration challenges, is consistent with the Commission's authorization of the same advanced metering technologies, with the same integration challenges, for SDG&E and SCE.

35. DRA and TURN have not forecasted the PVRR of any Title 24 PCT program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither Title 24 PCT program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade.

36. Reduction of Title 24 program costs related to marketing and incentive costs, commensurate with reductions to program participation, results in adopted Title 24 PCT program costs of $26,174,000 on a PVRR basis.

37. DRA and TURN recommend no PTR program costs, not because of any differences in what the estimated costs should be, but because of their positions that neither PTR program costs nor benefits should be included in the cost effectiveness analysis of the Upgrade.

38. PG&E requests $15.3 million in additional project management costs associated with additional project management efforts that will be required as the industry continues to evolve and offer new technologies.

39. In our analysis of PG&E's risk based allowance, we have determined that PG&E's requested additional project management costs should be considered as original AMI program costs, specifically under the risk based allowance for the original AMI project.

40. PG&E's technology assessment cost request has not been fully justified and appears to be excessive.

41. It is not clear that the currently proposed communication networks are deficient in particular respects, and it is not clear how BPL, MPL or IP would be incorporated into the currently proposed AMI structure.

42. There is potential value in having PG&E monitor market place developments.

43. There is value in pilot testing to ensure that the proposed network can be integrated into the AMI and will work as intended.

44. While laboratory testing and product demonstrations should first be the responsibility of those in private industry who will in the end profit from the various HAN related devices, there is merit to PG&E's alternate proposal to have

ratepayers fund certain technology assessment costs in conjunction with matching funds from other sources.

45. Potential problems such as security breaches, interference with bill reading and interruption of customers' service can be avoided by first testing devices in a lab that replicates PG&E's system.

46. There is value in having PG&E provide input to and obtain information from private sector projects and to interact with developers and other utilities as HAN standards are developed.

47. No party disputes PG&E's estimate of incremental training costs.

48. No party objects to the concept of a risk based allowance or contingency.

49. Analysis of risk for the Upgrade should consider the risk profiles specific to the Upgrade, rather than that of the original AMI project.

50. A review of PG&E's proposed risk factors does not cause any specific concerns with the magnitude of the factors or with the cost categories to which they are applied.

51. The types of equipment to be deployed and the number and types of vendors that will be managed during the project are elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts fort the Upgrade.

52. The electromechanical meters in Kern County, which have become stranded, were an element of PG&E's original AMI project.

53. Changed timing and scope are elements of the risk profiles that were considered in determining the reasonableness of PG&E's contingency amounts for the Upgrade.

54. Changed scope (i.e., advanced meters with higher functionality) is the driving factor that resulted in the electromechanical meters and associated equipment becoming obsolete.

55. For operation and maintenance, the only category of costs challenged by intervenors is that relating to expected calls to PG&E's call centers concerning the HAN device.

56. DRA recommends reducing PG&E's call center costs by 70% to reflect the fewer calls that will be received as a result of DRA's lower HAN adoption rate, despite its recommendation to reduce PG&E's HAN adoption rate by only 30%.

57. No party has challenged either PG&E's inclusion of field technician labor savings as a benefit or PG&E's quantification of these savings.

58. No party has challenged PG&E's inclusion of reduced bad debt savings as a benefit or PG&E's quantification of these savings.

59. No party has challenged PG&E's inclusion of reduced cash flow savings as a benefit or PG&E's quantification of these savings.

60. Whether the tax retirement benefit for meters is identified as a benefit or a reduction to costs, the net effect with respect to any benefit/cost analysis will be the same.

61. The need for reprogramming advanced meters is caused by the added functionality of the programmable meter itself.

62. The cost savings identified by PG&E, with respect to its remote programmability adjustment, are related to potential costs that never existed. Those costs are avoided because the meter that necessitates the costs can accomplish the task remotely.

63. Conservation benefits were not quantified in PG&E's original AMI proceeding.

64. The 1979 study by McClelland and Cook, used by DRA to reach its conclusion that day-late presentation of usage information affects space conditioning usage, does not provide persuasive evidence to support DRA's conclusions on this issue.

65. The shareholder risk/reward incentive mechanism for energy efficiency programs relates to energy efficiency and not conservation, and the conservation benefits for the Upgrade include both energy efficiency and conservation.

66. PG&E's estimate of 30% IHD penetration and DRA's estimate of 21% are based on new technology acceptance curves for different products (cell phones and CFLs).

67. There is sufficient evidence to determine that customers will use information obtained from IHDs to change their electricity usage patterns.

68. Both PG&E and DRA recommend that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade.

69. The IHD shows electricity usage, not gas usage.

70. The economic incentive for reducing gas usage is likely a result of a gas bill or an examination of gas rates rather than a customer looking at an IHD and noting electricity usage patterns.

71. With respect to customers that supposedly do not clearly differentiate electric and gas consumption by their appliances, there is no record evidence indicating what proportion of the customer base that might be. Furthermore, there is no record evidence indicating whether such customers would be the type that would even purchase an IHD.

72. With respect to the PTR program design, PG&E proposes a single-tier incentive, while DRA proposes a two tier incentive.

73. A two-tier PTR incentive has been adopted for SDG&E, and a two-tier PTR incentive settlement proposal for SCE has been deferred to SCE's Phase 2 GRC proceeding.

74. Requiring PG&E to propose a two-tier PTR incentive design in its November 2009 rate design window filing, will allow PG&E time to (1) work with DRA and other parties to work out program details; (2) consider the adopted design for SDG&E along with any solutions to practical considerations, if any; and (3) monitor and evaluate what has happened or will happen in SCE's Phase 2 GRC with respect to implementing a two-tier PTR program design.

75. That SEER is not a reliable predictor of energy performance or of demand reduction in California is supported by evidence.

76. There is evidence that there are energy savings ranging from 6% to 33%, associated with upgrading from a lower SEER system to a higher SEER system under different upgrading scenarios, although the number of units achieving expected savings is low (from 8% to 29%).

77. There is no statistically significant difference between the impacts expected from CPP and PTR incentives when estimated based on data from a side-by-side comparison of the two options for the same customer population.

78. The Anaheim study produced PTR program impacts nearly identical to the estimated impacts using the demand models from the SPP.

79. Rejection of TURN's proposed 30% elasticity adjustment is consistent with Commission action in D.08-09-039 regarding TURN's similar proposal in SCE's AMI proceeding.

80. While PG&E demonstrates that a non-CAC customer might realize significant savings under the PTR program under certain scenarios, there is no

evidence as to suggest what the expected scenario might be and what savings would result from such a scenario.

81. Regarding non-CAC customer participation in the PTR program, there will likely be a response beyond that of those who would participate for environmental or societal reasons.

82. In D.08-09-039, the Commission rejected TURN's proposed demand response guarantee for SCE, which is similar to TURN's proposed demand response guarantee for PG&E.

83. PG&E has produced evidence from which it can be concluded that its cost effectiveness analysis includes HAN facilitated CAC cycling for new Title 24 PCTs beyond the level needed to replace attrition associated with the 305 MW in the A/C settlement.

84. The Commission has no way of knowing whether or not any future CEC assumed costs would significantly affect the cost benefit analysis as it applies to the Upgrade.

85. There is no certainty that the Title 24 PCT regulations will be implemented in 2012, if ever.

86. Whether the amount of voluntary participation will grow, if the Title 24 PCT regulations are not enacted, is uncertain.

87. Regarding PG&E's estimated 0.75 kW/hour savings per customer for the PCT program, while PG&E gives a reasonable explanation of why 0.48 KW/hour savings may be low, it provides no convincing evidence to justify its assertion that different ramping strategies will necessarily result in 0.75 kW/hour savings.

88. Regarding the SmartAC program, while PG&E states that participation has grown to over 75,000 customers with the $25 incentive, and indicates that it is well on its way to achieving the 25% market penetration target, it does not

indicate where it is now and how much further it needs to go to meet the 25% target.

89. PG&E has produced no estimate of what a PCT device would cost, while TURN estimates costs to be in the range of $90 to $120, which is significantly higher than the $25 rebate.

90. No party has challenged PG&E's general cost recovery proposal.

91. In general, it is reasonable to allocate distribution infrastructure with distribution level EPMC related allocators.

92. PG&E's cost allocation methodology is consistent with how SDG&E's AMI related costs are allocated.

93. There were a number of settlements in Phase 2 of PG&E's 2007 GRC, which addressed marginal costs, revenue allocation and rate design. In the particular settlement on marginal costs and revenue allocation, Section VII.3 addresses rate changes between GRCs.

94. With respect to benefits recognition, there is no evidence that PG&E is mismanaging funds.

95. Recognizing AMI benefits when the meter is activated is reasonable, because no benefits can be realized until the meter is activated.

96. Regarding TURN's benefits recognition proposal, the Commission rejected a similar ratemaking proposal from TURN in D.06-07-027.

97. While benefits are trending $45 million behind schedule, the costs of the project are trending $161.9 million behind the original schedule.

98. PG&E's current deployment schedule still reflects an overall completion timeframe of five years.

99. No party has disputed the use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade.

100. DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory may result in additional benefits for the SmartMeter project.

101. That the deployment of electric and gas meters might vary, not only from what was originally planned but from updated deployment plans as time goes by, is not unexpected.

102. The manner in which the final deployment of meters evolves will reflect how PG&E is able to manage the effects of factors such as the availability of materials and equipment, the regulatory process, and changes in technology as the deployment of meters is progressing.

Conclusions of Law

1. This is an appropriate time to authorize deployment of HAN gateway devices for PG&E, and PG&E's request to do so is reasonable.

2. PG&E should work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

3. The increased functionality and the potential uses of the integrated load limiting connect/disconnect switches justify providing all electric residential customers with such switches.

4. PG&E's decision to ubiquitously deploy the advanced solid state meter for the SmartMeter Upgrade is reasonable.

5. PG&E should provide quarterly reports on the implementation progress of the SmartMeter Upgrade to the Commission's Energy Division and any interested parties.

6. PG&E should select the communication network(s) that provide the necessary functions in the most reasonable cost-effective manner.

7. PG&E's definition of incremental for cost effectiveness analysis purposes of the Upgrade is reasonable.

8. Any future requests to upgrade the SmartMeter Program should be critically reviewed with the understanding that our interpretation of cost effectiveness in this proceeding is appropriate for the circumstances that exist today and may well be inappropriate for circumstances that exist in the future.

9. The use of a total cost effectiveness analysis should be limited to showing whether or not the cost effectiveness of PG&E's SmartMeter program is in the range or generally comparable to that of SDG&E and SCE.

10. It would be inappropriate to impose DRA's proposed meter device costs on PG&E without assurance that the related meter devices provide the necessary functions, without assurance that the vendors are capable of providing the equipment when needed, and without knowledge of the type of warranties that are associated with the costs.

11. PG&E's decision to proceed with the HAN retrofit was reasonable.

12. To account for uncertainties and attempt to ensure that ratepayers only fund appropriate costs, it is reasonable to reduce adopted funding for the HAN retrofit by $5,500,000 (plus $550,000 for the related risk based allowance).

13. For the electromechanical meter upgrade, a cost of $18.8 million for the upgraded system is reasonable.

14. PG&E's general direction in attempting to deploy a solution that would bring the highest probability of transmitting a signal from the electric meter to an interior wall of the customer's premises is reasonable.

15. PG&E should adapt the implementation of HAN connectivity over time consistent with approaches and solutions that are being addressed and developed, currently and in the future, by those in the industry that are addressing these issues.

16. Because we have included the benefits of the PTR program in evaluating the cost effectiveness of the Upgrade, it is also appropriate to include the $4.0 million in IT costs related to the PTR program, in rates, as requested by PG&E.

17. IT costs associated with the Title 24 PCT program should be recovered in conjunction with PG&E's cost recovery of the Title 24 PCT program costs.

18. Because we have included the benefits of the Title 24 PCT program in evaluating the cost effectiveness of the Upgrade, it is appropriate to include the costs of Title 24 PCT program in that evaluation.

19. Since this decision approves a two-tier PTR incentive structure that will be detailed by PG&E in a November 2009 rate design window filing, it would be more appropriate to address the costs of such a program at the same time, rather than as part of this decision.

20. It is reasonable to use PG&E's estimated PVRR amount of $27,592,000 that is associated with a single tier PTR incentive structure, for the purpose of evaluating the cost effectiveness of the Upgrade in this decision.

21. Since we have adopted DRA's proposed HAN adoption rates, which were derived by applying a 0.7 scalar to PG&E's proposed adoption rates, it is

reasonable to apply the same 0.7 scalar to PG&E's proposed call center costs, resulting in an adopted call center estimate of $319,000, which is $136,000 less than projected by PG&E.

22. With respect to devices that would enable home computers to function as in-home displays, technology assessment costs should be borne by those in private industry who will, in the end, profit from the device.

23. PG&E's proposed risk base allowance methodology along with the specific factors themselves and the categories of cost to which they are applied are reasonable.

24. It is reasonable that the additional project management costs requested by PG&E as part of the Upgrade should instead be covered by the risk based allowance adopted in D.06-07-027.

25. With respect to laboratory testing and product demonstrations, it is reasonable that ratepayers provide at least some of those costs related to protecting PG&E's system from such potential problems as security breaches, interference with bill reading and interruption of customers' service, which can be avoided by first testing devices in a lab that replicates PG&E's system.

26. It is reasonable to allow $6 million as the ratepayers' share of laboratory testing and product demonstration costs, with the understanding that PG&E can only use those ratepayer provided funds to the extent that it matches those funds from other sources. Any unspent funds for this particular category should be credited back to ratepayers.

27. Since the decisions to deploy the electromechanical meters in Kern County were made by PG&E in conjunction with the original AMI authorization, it is appropriate that the consequences of those decisions should be reflected as part of that same authorization.

28. It is reasonable that the stranded costs related to the electromechanical meters deployed as part of PG&E's original AMI project should be covered by the risk based allowance authorized by D.06-07-027 for the original AMI project.

29. PG&E's estimates of field technician labor savings, reduced bad debt savings, improved timing of cash flow savings, and the tax benefit from meter retirement are reasonable and should be adopted.

30. To assign the PG&E identified remote programmability benefit as an incremental benefit in the cost effectiveness analysis of the Upgrade is illogical and inappropriate.

31. Rather than reducing PG&E's estimate of electric conservation benefits by 12% as recommended by DRA, it would be appropriate, when the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, for PG&E to ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the Upgrade.

32. It is reasonable to be conservative and to adopt DRA's IHD penetration estimate of 21%, partly because of the speculative nature of the forecasts and partly due to TURN's legitimate concerns regarding the cost of the IHD devices.

33. It is reasonable that the more recent avoided costs should be used for the purpose of estimating electric conservation benefits for the Upgrade.

34. Since we do not feel that customers' decisions as to whether they should limit or curtail gas usage are significantly enhanced by the presence of IHDs that only display electricity usage patterns, zero gas conservation benefits should be used in the cost effectiveness analysis of the Upgrade.

35. For statewide consistency purposes, it is reasonable to impose a two tier PTR incentive design on PG&E and to require PG&E to propose such a design in its November 2009 rate design window filing.

36. Consistent with our acceptance of PG&E's definition of "incremental" for purposes of determining Upgrade costs and benefits, it is appropriate to include PTR benefits that result from PG&E's SmartMeter project and that were not quantified in PG&E's original AMI proceeding.

37. Even though the climate and other factors particular to California are not the same as that assumed for SEER purposes, it is reasonable to assume that as manufacturers attempt to make more efficient systems to comply with upgraded SEER levels, there will be some effect of demand reductions and energy savings in California.

38. It is reasonable to reduce TURN's proposed SEER adjustment by 50% to reflect increased AC efficiencies that result from increased SEER requirements.

39. Regarding non-CAC customer participation in the PTR program, it is reasonable to split the difference between the PG&E and TURN forecasts, resulting in a non-CAC customer participation rate of 35.5%.

40. For the same reasons expressed by the Commission in D.08-09-039, in rejecting TURN's proposed demand response guarantee for SCE, it is appropriate to reject TURN's proposed demand response guarantee for PG&E.

41. Similar to what was required for SCE in D.08-09-039, PG&E should report to the Commission on the energy savings and associated financial benefits of all DR, load control, energy efficiency, and conservation programs enabled by AMI, including PCT programs, Peak Time Rebate programs, and other dynamic rates for residential customers.

42. It is not appropriate to completely dismiss the use of Title 24 PCT benefits in the Upgrade cost effectiveness analysis, as proposed by both DRA and TURN.

43. Regarding Title 24 PCT benefits, it is reasonable to split the difference between the PG&E and TURN forecasts, resulting in a PVRR of $83,428,000 as opposed to PG&E's estimate of $129,401,000.

44. PG&E's general cost recovery proposal is reasonable.

45. For the Upgrade, it is reasonable to continue the use of the cost allocation methodology adopted by the Commission for PG&E in D.06-07-027.

46. Parties are not precluded from raising issues related to the allocation of SmartMeter costs in PG&E's next Phase 2 GRC proceeding.

47. In order to honor the settlement process, we have no alternative but to impose the principles for rate changes between GRCs, as identified in PG&E's TY 2007 Phase 2 marginal cost and revenue allocation settlement, in allocating the Upgrade related revenues to customer classes, including the street light class.

48. It is not necessary to change the benefits recognition procedures as proposed by DRA.

49. PG&E's reasons for rejecting TURN's $44.8 million ratepayer credit proposal are persuasive.

50. The use of PG&E's results of operations model for the purposes of calculating the revenue requirements associated with the Upgrade is reasonable.

51. PG&E's results of operations model should be used to calculate the Upgrade revenue requirements using the costs adopted by our decision today.

52. DRA's recommendation that PG&E pursue water meter AMR with water utilities in its service territory is reasonable.

53. In order to pursue AMR for water meters, PG&E should work with the water utilities in its service territory, either through multi-party workshops or

direct dialogue and report back to the Commission on a quarterly basis until completed.

54. It would not be an efficient use of Commission resources to reopen the record to consider all aspects of the information contained in the Attachment A, a process that might require additional evidentiary hearing and briefs.

55. DRA's Motion to Reopen the Record should be denied.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to proceed with the proposed SmartMeter Upgrade, subject to the conditions and costs specified in this decision.

2. PG&E's general cost recovery proposal is adopted.

3. PG&E shall file an advice letter no later than 30 days from the effective date of this decision, to implement rates for 2009 to cover the costs of the SmartMeter Upgrade.

4. PG&E shall use its results of operations model incorporating the costs adopted in this decision to determine the appropriate revenue requirements for the SmartMeter Upgrade project. Detailed results shall be included in PG&E's advice letter that implements rates for the SmartMeter Upgrade.

5. PG&E shall work with the other major California energy utilities to strive for statewide, easily understandable information and other resources, as appropriate, to increase consumer awareness of commercially available HAN technologies and HAN-enabled benefits and to promote the adoption of such HAN technologies by consumers in order to facilitate their ability to understand their energy consumption and costs and to optimally utilize their discretionary options.

6. In its next general rate case (GRC) for test year 2011, PG&E shall make an affirmative showing that it has avoided double recovery of any authorized SmartMeter Upgrade costs, and that any requested costs in its 2011 GRC are consistent with the limits of recovery adopted in this decision.

7. PG&E shall provide quarterly reports on the implementation progress of the SmartMeter Upgrade to the Commission's Energy Division and any interested parties. PG&E shall consult with the Energy Division to determine what information to provide and to coordinate reporting requirements ordered in Decision 06-07-027.

8. When the future of the energy efficiency incentive mechanism is clarified and if further incentives are authorized, PG&E shall ensure, through testimony in that future energy efficiency proceeding, that there is no double counting of energy efficiency embedded in the conservation benefits related to the SmartMeter Upgrade.

9. A two-tier peak time rebate incentive design is adopted for PG&E. PG&E shall present a proposal to implement such a design in its November 2009 rate design window filing. The proposed rate design shall be consistent with the rate design guidance in D.08-07-045.

10. Similar to what was required for Southern California Edison Company in Decision 08-09-039, PG&E shall report to the Commission on the energy savings and associated financial benefits of all demand response, load control, energy efficiency, and conservation programs enabled by advanced metering infrastructure, including programmable communicating thermostat programs, Peak Time Rebate programs, and other dynamic rates for residential customers. PG&E shall file annual reports in April of each year until 2019. PG&E shall work with Energy Division to develop a reporting format for this information, and to

determine where the reports should be filed. PG&E may request recovery for the incremental costs of this reporting requirement in appropriate cases.

11. In order to pursue automated meter reading for water meters, PG&E shall work with the water utilities in its service territory, either through multi-party workshops or direct dialogue. PG&E shall report back to the Commission on the status of its efforts and results of its discussions on a quarterly basis, beginning April 11, 2009, until completed.

12. The Division of Ratepayer Advocates Motion to Reopen the Record, filed February 17, 2009, is denied.

13. Application 07-12-009 is closed.

This order is effective today.

Dated March 12, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

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