Pacific Gas and Electric Company

Advanced Metering Infrastructure

January 2010 Semi-Annual Assessment Report and SmartMeter™ Program Quarterly Report (Updated)

(CPUC Decisions 06-07-027 and 09-03-026)

January 31, 2010

Pacific Gas and Electric Company
Advanced Metering Infrastructure Semi-Annual Assessment Report
SmartMeter™ Program Quarterly Report
January 2010

I. Executive Summary

A. Introduction

This is Pacific Gas and Electric Company's (PG&E or the Company) seventh semi-annual assessment report (Report) regarding the deployment of PG&E's Advanced Metering Infrastructure (AMI) Program (now the SmartMeter™[1] Program) and serves as the third quarterly report for the SmartMeter™ Program Upgrade. In Decision 06-07-027 (the AMI Decision), the California Public Utilities Commission (CPUC or Commission) approved PG&E's SmartMeter™ Program proposed in Application 05-06-028. In Decision 09-03-026 (the Upgrade Decision), the CPUC approved, with certain modifications, PG&E's Application 07-12-009 (Upgrade Application) to recover incremental costs associated with the SmartMeter™ Program Upgrade.

Ordering Paragraph 4 of the AMI Decision requires PG&E to provide regular summary reports to the Commission's Energy Division and Division of Ratepayer Advocates (DRA) to enable the Commission to monitor the progress of PG&E's SmartMeter™ Program. PG&E files these reports on a monthly basis. Ordering Paragraph 16 of the AMI Decision requires the following: "PG&E shall provide the Chief Administrative Law Judge, Energy Division, DRA and all other parties in this proceeding a semi-annual report assessing AMI deployment as set forth herein, beginning six months after the effective date of this decision."

[1] SmartMeter™ is a trademark of SmartSynch, Inc. and is used by permission.

Ordering Paragraph 7 of the Upgrade Decision requires the following: "PG&E shall provide quarterly reports on the implementation progress of the SmartMeter™ Upgrade to the Commission's Energy Division and any interested parties." After consultation with the Commission's Energy Division, PG&E has prepared this Report to comply with the requirements of both Ordering Paragraph 16 of the AMI Decision and Ordering Paragraph 7 of the Upgrade Decision.

The AMI Decision explains that the semi-annual report is intended to update the Commission in the following areas: advances in AMI technology; a self-assessment of AMI system operating performance based on performance criteria established in consultation with the Energy Division and DRA; updated cost-effectiveness review; and the ability to provide real-time usage data and customer interest in such data.[2] PG&E conferred with representatives of the Energy Division and DRA to discuss the scope of topics to be addressed and the metrics by which AMI is to be assessed and incorporated staff comments and suggestions into this Report.

B. Overview of the SmartMeter™ Program

PG&E's SmartMeter™ Program continues to progress through its objectives, including deployment of endpoint devices and associated network equipment, as well as implementing new information technology (IT) functionality. This section of the Report provides an overview of Program developments and PG&E's progress on individual elements of the Program over the past six months.

PG&E has been an integral player in helping to shape the direction of Smart Grid standards especially in the area of AMI and the Home Area Network (HAN). In November 2009, PG&E won the 2009 best "Advanced Metering Initiative in a North

[2] D.06-07-027 at pp. 57-58.

American IOU" award presented by the Global Smartgrid/AMI Utility Peer Group of the Utility Peers Network. PG&E was chosen from entries from around the world, with participation from utilities based in Europe, Asia, Africa, Australia, the United States and Canada. This is the second year in a row that PG&E has won this award.

1. Advances in AMI Technology

PG&E currently has three field network communication technologies available for use in its SmartMeter™ Program:

1. Radio Frequency (RF) Mesh technology, provided by Silver Spring Networks (SSN) – electric metering;
2. RF technology, provided by Aclara RF (Gas RF) - gas and electric metering; and
3. Power line carrier (PLC) technology, provided by Aclara PLC - electric metering.

PG&E will continue to operate all of these networks until the replacement of all electric endpoints utilizing PLC. PG&E is currently deploying advanced solid-state electric meters operating on the SSN network, which include an integrated connect/ disconnect switch and a HAN gateway device.

PG&E continues to evaluate metering and network collector technology as the industry advances. An effort is currently underway to identify and approve engineering solutions utilizing specific technologies and products that enable PG&E to deploy in difficult-to-reach meter locations such as urban areas and remote locations. These solutions may require one of the technologies noted above, or other technologies not yet available, as conditions dictate. For example, PG&E is currently conducting an analysis of gas RF mesh communication technologies as one potential solution for particularly hard-to-access gas service points.

PG&E continues to participate in industry activities related to advanced metering and communication networks, as well as monitoring announcements and activities that are significant in the industry. These activities allow PG&E to be actively involved with and aware of industry developments.

PG&E's August 2009 application for federal funding under the American Recovery and Reinvestment Act of 2009 was denied. PG&E's intention was to pilot various technologies to allow for the extension of scope and volume of planned HAN testing. PG&E's request for funding in this area was consistent with the Commission's request for PG&E to seek matching funds to help support new technology assessment costs. (Upgrade Decision, p. 86)

In the SmartMeter™ Upgrade Decision, PG&E was allowed $6.0 million in laboratory and product demonstration costs, with the understanding that PG&E can only use those ratepayer-provided funds to the extent that it matches them with funds from other sources[3]. Although PG&E has yet to incur such costs, it has identified approximately $200,000 in matching funds (for HAN trials) and future amounts totaling $2.5 million. PG&E is continuing to pursue additional sources of such matching funds.

During the second half of 2009, PG&E began a lab-based evaluation of a HAN-enabled in-home display device, and has outlined the preliminary network architecture. This evaluation will continue through the first half of 2010 with a technical evaluation in selected premise environments and feedback on usefulness from focus groups through the second half of 2010.

PG&E has expanded its evaluation and testing of enhanced network technologies to support its vision for the Smart Grid of the future. PG&E's vision includes integration of meter data, distribution automation and automated load control to maximize the distribution system reliability using technology as discussed in Section II of this Report.

[3] D.09-03-026, Conclusion of Law 26, p 191.

2. Bakersfield-Related Deployment Developments Including Class Action Lawsuit

Since the filing of PG&E's last semi-annual report, California State Senator Dean Florez held "Town Hall" style meetings in Fresno and Bakersfield, at which some customers questioned the accuracy of PG&E's SmartMeter™ Program. PG&E has researched these customer complaints and determined that the complaints were largely due to usage changes in response to seasonal weather (particularly 17 days in July 2009 with temperatures at or above 100 degrees), compounded by higher rates in tiers 3, 4, and 5, and recent rate increases in tiers above baseline quantity. PG&E's research of the customer complaints, as well as PG&E's meter testing policies, demonstrate that the SmartMeter™ Program is accurate.

The CPUC has announced that it will conduct an independent, third-party investigation of PG&E's SmartMeter™ Program to verify meter accuracy. PG&E supports the CPUC's independent investigation and testing of installed PG&E SmartMeter™ devices.

In October 2009, a single customer filed a class action lawsuit against PG&E in which he alleged failures and fraud associated with PG&E's SmartMeter™ Program. PG&E believes the lawsuit is without merit. PG&E filed a demurrer in Kern County Superior Court in which it asserted that the Court lacks jurisdiction to hear the lawsuit because the subject of the lawsuit relates to matters within the exclusive jurisdiction of the CPUC. PG&E requested that the Court dismiss the lawsuit or, alternatively, defer to the CPUC's primary jurisdiction and stay the lawsuit. PG&E's demurrer is pending.

3. Progress in PG&E's AMI Deployment

PG&E continues to deploy solid-state electric meters communicating over the SSN RF Mesh network and gas modules communicating over the Aclara RF network. During the second half of 2009, PG&E achieved a milestone in network deployment by crossing the half-way mark for both electric and gas network deployments. As of December 31, 2009, 886 SSN access points (APs) have been installed, which represent approximately 75 percent of a planned total population of 1,182 APs. Installation efforts continue on the Aclara gas RF network, with a total of 3,632 data collection units (DCUs) installed through December 31, 2009, representing approximately 73 percent of a planned total population of 5,000 DCUs at project completion.

As of December 31, 2009, approximately 4,615,669 meters (approximately 2,305,883 electric and approximately 2,309,786 gas) have been converted to, or replaced with, SmartMeter™ technology, representing approximately 46 percent of the total PG&E meter population. Of this number, approximately 2,574,000 meters were "activated" and the benefits associated with completed meter reading routes were recorded to the gas and electric SmartMeter™ balancing accounts ($1.9543 per meter per month for electric[4] and $1.0366 per meter per month for gas).

In the third quarter of 2009, the Program ceased the replacement of previously installed PLC endpoints (without HAN or remote connect / disconnect), after the summer energy bill complaints from customers in Kern County and surrounding areas resulted in customer concerns regarding the accuracy of SmartMeter™ devices and the implementation of AMI technology as described in the Section above.[5]

During the second quarter of 2009, PG&E discovered a limited number of cases of SmartMeter™ radio interference with customer electronics, including ground fault circuit

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4 The $1.7722 per electric meter per month applied through March 2009 was raised to $1.9543 in April 2009 with the partial implementation of the IT functionality for remote connect / disconnect consistent with the Upgrade Decision.

5 Section III provides statistics on the replacement effort.

interrupters (GFCI) and arc fault circuit interrupters (AFCI). In response, PG&E implemented a policy to defer meter installations at customer premises that PG&E is aware could potentially be affected by radio frequency interference. PG&E plans to install an adjustable voltage meter to prevent potential interference at these recorded locations. These adjustable meters are currently in final acceptance testing at PG&E. Upon final acceptance and approval, a schedule will be developed to deploy these meters at the premises where installation was deferred.

PG&E has initiated significant customer outreach activities to address customers' concerns including a customer satisfaction survey, the improvement of deployment outreach activities through enhanced direct customer educational materials and pre-deployment customer and community outreach events. In addition to the accuracy tests performed at the manufacturers and the random sample testing performed by PG&E at its Fremont Meter Shop, PG&E will field-test any SmartMeter™ device upon customer request. PG&E has conducted over 1,500 field accuracy tests and is in the process of implementing an additional random quality testing program throughout its service territory.

PG&E also continues to manage and evaluate the impact of additional requirements from other regulatory decisions on the SmartMeter™ deployment. In particular, PG&E is currently accelerating the deployment of meters, network equipment and change management activities to serve large Commercial and Industrial customers who will be defaulted to Peak Day Pricing rates on May 1, 2010. Customers affected by the May 1, 2010 default date are customers with demands greater than 200 kW (demand being measured in kilowatts, not kilowatt-hour units). The Program expects to spend up to approximately $8.4 million on this effort.

Further details of the SmartMeter™ Program's deployment status are detailed in Section III of the Report.

4. Program Costs and Benefits

SmartMeter™ Program expenditures through December 31, 2009 totaled approximately $1,337 million (61 percent) of the $2,206 million authorized project amount. Initially, $2,028 million of expenditures were allocated to workstream budgets covering field deployment, information technology, operations and marketing, and the program management office (PMO). PG&E actively monitors workstream expenditures against budget and forecast to identify additional costs and cost savings likely to occur during the Program period. The Program has authorized workstreams to incur such additional costs, forecasted over the course of the project period, totaling approximately $159 million.

To date, PG&E's SmartMeter™ Steering Committee has authorized the drawdown of approximately $2.9 million of the $177.8 million risk-based allowance authorized by the Commission. With more than two years remaining to Program completion, future unforeseeable issues will likely arise, which, along with the resolution of currently estimated costs, will require upward and downward adjustment to workstream authorized budgets, and ultimately further drawdown of PG&E's risk-based allowance. At this time, PG&E continues to believe that overall spending will remain within the total CPUC-authorized amount of $2,206 million at Program completion.

As previously indicated, the total number of activated meters on December 31, 2009 was approximately 2,574,000. The related benefit savings credited to the gas and electric balancing accounts through this same date were $42.1 million. These amounts are consistent with the method for calculating and recording benefits provided in PG&E

testimony and both the AMI and Upgrade Decisions. Further details of the SmartMeter™ Program's cost and benefit status are detailed in Section IV of the Report.

5. System Performance Criteria

Electric and gas billing data collection failure rates have increased since last reported. An increased deployment volume in areas with poor cellular coverage contributes to lower performance, while firmware upgrades and supplemental network designs for existing and new installations improves performance. PG&E believes the system is continuing to perform as designed and within the specified system requirements. The system performance criteria are defined and discussed in Section V of the report.

6. Customer Interest in Accessing Real-Time Usage and Pricing Information

PG&E launched its SmartRate Program in May 2008 as reported in the July 2008 Semi-Annual Report. In 2009, PG&E called fifteen SmartRate Program SmartDay[6] events (on June 29, June 30, July 13, July 14, July 16, July 21, July 27, August 10, August 11, August 18, August 27, August 28, September 2, September 10, and September 11). Details of the SmartRate Program are provided in Section VI of the Report.

Additionally, as directed by the Commission, PG&E continues to monitor developments concerning direct load control, as well as customer interest in accessing real-time energy information and time of use (TOU) rates. An update on the research efforts is detailed in Section VI of the Report.

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[6] SmartDay events are called between May 1 and October 31, Monday through Friday, on days when temperatures exceed a pre-determined threshold. Calling a SmartDay event asks residential customers to conserve energy between the hours of 2 p.m. and 7 p.m. and commercial customers between the hours of 2 p.m. and 6 p.m.

7. SmartMeter™ Information Technology Progress

During the second half of 2009, PG&E continued the detailed testing and implementation associated with the development of complex IT systems and interfaces required to support the SmartMeter™ Program. Highlights of this continuing IT development over the past six months include:

1. Implementation of OMT (Outage Management) enhancements;
2. Implementation of power factor billing;
3. Verification of system scalability to 5.5 million meters on an individual system or 'silo' basis; and
4. Installation of an SSN system upgrade to version 3.9.

PG&E's IT development plan for the first half of 2010 includes the following four key elements:

1. Installation of an SSN system upgrade to version 4.1;
2. Implementation of KVAR[7] functionality;
3. Implementation of an SSN Gas Pilot; and
4. Continued analysis of SmartMeter™ system scalability from 6 million meters through final deployment at 11 million meters on an end-to-end basis.

In addition to continued IT system development to support the SmartMeter™ Program, PG&E is analyzing and beginning implementation of additional IT system modifications to comply with the Commission's Dynamic Pricing Decision 08-07-045. PG&E filed the 2009 Rate Design Window Application 09-02-022 on February 27, 2009 in compliance with Decision 08-07-045, to seek authority to implement Peak Day Pricing

[7] KVAR is an electrical term for KiloVolt-Ampere-Reactance, technology used in energy controllers to reclaim, store and supply power to inductive motors and loads. It enables SmartMeter™ data collection, validation and billing of customers whose usage necessitates the measurement of reactive voltage.

rates. A CPUC decision in this proceeding is pending. Also in compliance with Decision 08-07-045, PG&E will seek authority to implement Real-Time Pricing rates in its planned March 2010 application in Phase 2 of PG&E's 2011 General Rate Case (GRC).

The scope and timing of the required changes arising from the Dynamic Pricing Decision and subsequent related proceedings require PG&E to re-prioritize its IT system development plans in an effort to implement interval billing and KVAR functionality by May 2010. In addition to these efforts, SmartMeter™ Program IT is also preparing to be operationalized in 2011, and consequently, is validating the "architectural roadmap" for IT-enabled functionalities related to the SmartMeter™ Program beyond 2010.

II. Advances in AMI Technology

A. Introduction

Over the past six months there has been significant growth in industry interest in AMI technology. PG&E has participated internationally in meetings and other industry efforts. PG&E continued its investigation of extending the AMI communications network to support Distribution Automation (DA) applications, including automated distribution reconfiguration and load control. The initial evaluation concluded that these applications are in fact suitable for the AMI network. PG&E will continue the development of more extensive testing and integration plans.

B. PG&E Distribution Automation Investigations

In the July 2009 Report, PG&E noted its evaluation of both the implementation of Communicating Faulted Circuit Indicators (CFCI) and the S&C Electric Company's Intelli-TEAM auto-reconfiguration system. PG&E continues to work with both the communications manufacturers and traditional CFCI vendors to facilitate joint manufacture. The development of a low-cost CFCI will improve PG&E's ability to respond quickly to outages and the additional fault information will make it possible to deploy the correct equipment and personnel immediately. PG&E's Intelli-TEAM product currently has non-SSN radios. PG&E evaluated SSN radios but has deferred field testing pending evaluation of the full system architecture. Finally, PG&E will continue to work with other fault indicator vendors.

An important extension to this project under consideration is the linking of automatic load shedding with automatic circuit reconfiguration. Changing the circuit configuration for automatic service restoration can shift the load or initiate load shedding which may be needed to avoid overloads.

The next steps regarding distribution automation investigation include testing of the radio traffic generated in integrated AMI/DA applications, completing a review of data model options, and creating use cases to be used for system integration.

C. Technology Industry Updates

PG&E continues to lead and participate in industry activities related to advanced metering and communication networks, including membership in professional organizations and attendance at conventions and trade shows. In September 2009, PG&E presented at the first International Conference on SmartGrid Initiatives in San Antonio, Texas. At the Utilimitrics Autovation in October 2009, PG&E's SmartMeter™ Programming Engineer Manager received the Malmezian Award, an award given to a utility professional who has demonstrated outstanding achievement in the areas of AMI, automated meter reading (AMR), meter-data management, outage management or revenue protection.

During the second half of 2009, PG&E presented at the following industry events:

- Smart Grid Summit, DC
- Utilimetrics Autovation
- Smart Energy West Coast
- Marcus Evans Smart Grid Initiatives conference
- Grid Week, DC
- Metering Europe, Barcelona
- Greentech Media's Networked Grid event (where PG&E acted as host utility)
- Financial Research Associates Smart Pricing for a Smart Grid world conference
- Canadian Electric Association meeting, Toronto

PG&E actively participates in the following significant activities as part of the Company's commitment to an open and inter-operable Smart Grid:

- UCA Open Smart Grid (Chair) – Providing oversight over UCA's Utili-App, Utili-Ent, Utili-Sec, and Utili-Comm groups. The UCA Open Smart Grid committee (a utility leadership committee) has been integral in setting utility requirements in UCA and providing them to the appropriate standards bodies.
- UCA Open Auto DR (Chair) – Transforming the Lawrence Berkeley National Laboratory Automated Demand Response requirements from a specification to a standard.
- Institute of Electrical and Electronics Engineers (IEEE) 802.15.4 Tg (Chair) – Producing IEEE 802 standards for Smart Utility Networks.

- UCA OpenHAN – Setting technology independent requirements to technology alliances.
- UCA Utili ENT – Setting standards for the AMI Enterprise.
- UCA Utili SEC – Establishing open security standards for the Smart Grid.
- UCA ADE – Defining a common interface for exchange of information between utilities and third parties for customer data.
- SAE J2836 – Setting the communication standards between Vehicle and Grid for purposes of energy transfer.

PG&E continues to believe that making these standards inter-operable through a comprehensive certification process should be one of the industries highest priorities. PG&E will continue to work with major industry stakeholders and the above organizations in assisting with that challenge.

Since PG&E's July 2009 Report, there have been a number of significant industry announcements. They include:

- In September 2009, LS Industrial Systems, the leading provider of utility infrastructure in Korea, and SSN, a global leader in Smart Grid solutions, executed a business cooperation agreement in a signing ceremony at GridWeek 2009, the most influential event for the Smart Grid industry. The agreement outlines complementary areas of technology expertise and establishes a roadmap for new market entry for the partnering companies. (http://www.silverspringnet.com/newsevents/press_releases.html)
- In September 2009, SSN announced that it entered into an agreement to acquire Greenbox Technology, an innovative provider of web-based energy management software. The Greenbox™ interactive energy management web portal, built by

the creators of Flash™, delivers on a key benefit of the Smart Grid - enabling consumers to track, understand and manage their energy usage more efficiently. (http://www.silverspringnet.com/newsevents/press_releases.html)

- In September 2009, Landis+Gyr, a leading provider of smart metering solutions, introduced the new release of its residential system software, with a new brand name, Gridstream AIM. The software presents the fourth generation of the company's AMM systems and 25 years of AMM experience. Gridstream AIM is the flagship of Landis+Gyr's Gridstream solution portfolio for advanced metering management.

(http://www.landisgyr.com/en/pub/media/press_releases.cfm)

- In September 2009, Iskraemeco, Itron Inc., and Landis+Gyr announced a significant initiative in the development of inter-operable smart meters supporting utility applications. The three companies expect the new offering will promote faster and broader deployment of advanced metering management (AMM) devices and services based on open standards, thereby responding to a compelling customer demand.

(http://www.landisgyr.com/en/pub/media/press_releases.cfm)

- In September 2009, Itron Inc. announced expanded functionality for its industry-leading OpenWay CENTRON smart meters. The enhanced meter will allow utilities, within their current AMR systems, to seamlessly migrate to a smart grid/AMI environment.

(http://www.itron.com/pages/news_press.asp?year=2009)

- In September 2009, Itron Inc. announced the start of full field deployment for its OpenWay AMI solution to Southern California Edison (SCE), an electric service provider to nearly 14 million people in central, coastal and southern California. (http://www.itron.com/pages/news_press.asp?year=2009)

- In September 2009, Aclara, a leader in Intelligent Infrastructure™ solutions for utilities and part of the Utility Solutions Group of ESCO Technologies Inc., introduced a revolutionary, mesh-based wide-area network (WAN) for utilities at Autovation 2009. The Aclara Smart Communications Network is a high-bandwidth, standards-based, broadband solution that will bring together existing utility assets and applications into a single network. PG&E plans to test this in the future.
(http://www.aclara.com/pages/pressreleases.aspx)
- In October 2009, SSN announced it has been named a Global Cleantech 100 company by Guardian News and Media and Cleantech Group™, LLC, providers of leading research, events and advisory services for the cleantech ecosystem. (http://www.silverspringnet.com/newsevents/press_releases.html)
- In October 2009, SSN was selected by American Electric Power for the utility's Smart Grid programs at its operating companies, Indiana Michigan Power and AEP Ohio. SSN is providing its field proven, Internet-Protocol-based technology, which creates an end-to-end, secure and intelligent platform for the Smart Grid. (http://www.silverspringnet.com/newsevents/press_releases.html)
- In October 2009, Landis+Gyr won the largest industrial, commercial and grid (ICG) meter contract to date in Eastern China. The company will deliver over 600 grid meters to the Jiangsu Power Grid enabling improved utility energy efficiency and both the quality and availability of energy data. (http://www.landisgyr.com/en/pub/media/press_releases.cfm)

- In October 2009, Siemens and Landis+Gyr agreed to a partnership in order to elaborate common standards. The standards will not only establish interoperability but will also give utilities the requisite security for their investments in smart grids. (http://www.landisgyr.com/en/pub/media/press_releases.cfm)
- In October 2009, Itron Inc. announced that it has selected Accent S.p.A., a leading fabless System-on-Chip (SoC) provider offering highly differentiated platform-based SoC solutions, to supply a newly developed integrated circuit for its OpenWay® CENTRON® smart meter product line. The new design will integrate the latest ARM processor technology, a complete ZigBee wireless solution (RF, baseband and protocol stack), as well as an LCD driver and on-chip embedded flash memory to deliver best-in-class performance, highly reduced BOM and lowest system cost. (http://www.itron.com/pages/news_press.asp?year=2009)
- In October 2009, Sensus announced that it has reached the 200th customer milestone for its line of Sonix® ultrasonic gas meters, an advanced measurement technology that features fewer components than mechanical meters and delivers improved performance. Since the market release in 2003, more than 200 customers worldwide, including twenty major gas distribution companies, are taking advantage of the benefits of Sonix® meters. (http://www.sensus.com/Module/PressRelease/PressReleaseList)

III. Progress in PG&E's AMI Deployment

A. Overview

PG&E continues to manage its meter and network deployment activities in parallel with the development and implementation of the IT systems and interfaces necessary to support SmartMeter™ functionality. The deployment schedule is dependent upon the availability of a trained workforce, an effective supply chain to maintain an efficient installation process, and customer availability to have equipment changes at their service location. Deployment planning adjustments may be required due to any number of factors, including adverse customer impacts, supply chain considerations, labor availability, and technology considerations, which could affect the scheduling of meter endpoint installations.

As of December 31, 2009, PG&E had converted or installed approximately 4,615,669 meters (including retrofits) with SmartMeter™ technology. As noted above, the Upgrade Decision approved PG&E's plan to replace all electric meters without Upgrade technology. PG&E deployed 189,538 SSN retrofit endpoints to replace PLC endpoints. PG&E's progress as of December 31, 2009 is summarized in Table III-1.

Table III - 1

AMI Project Status as of December 31, 2009

Progress Toward Completion	Total Budgeted Plan	Actual	% of Total Project Plan Installed
Electric Network - RF Network	1,182	886	75%
Gas Network Collectors	5,000	3,632	73%
Electric Network Enabled Locations	5,275,099	3,987,349	76%
Electric Meter-module installations*	5,645,594	2,305,883	41%
Electric Meter-module Activated	5,275,099	1,085,000	21%
Gas Network Enabled Locations	4,458,024	3,238,309	73%
Gas Meter-module installations	4,458,024	2,309,786	52%
Gas Meter-module Activated	4,458,024	1,489,000	33%

*Includes installation of retrofitted SmartMeters™.

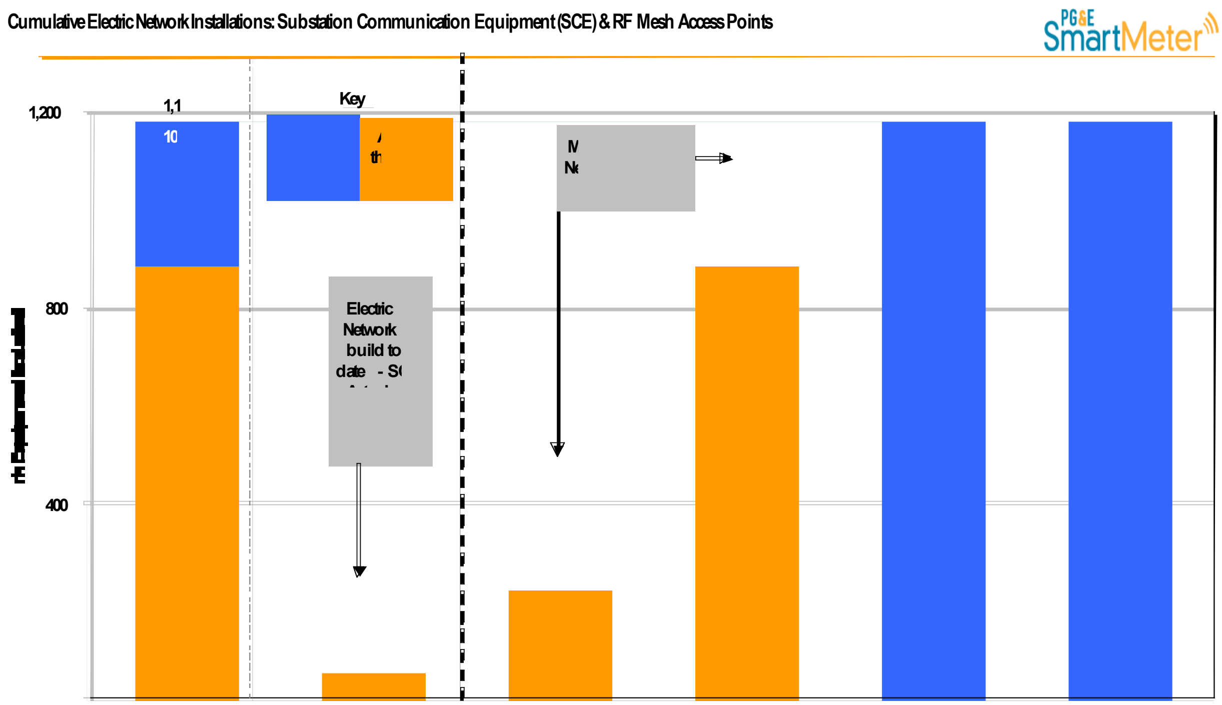
Note: Meter growth occuring in 2011 and 2012 is funded in the 2010 GRC and not included in the above table or the following graphs.

B. Actual Infrastructure Installations

In the six months since the July 31, 2009 Report, PG&E has continued to make progress in the deployment of gas and electric network infrastructure, the installation of gas and electric meter modules, and the activation of gas and electric meters. As previously indicated, technology decisions may result in deployment planning adjustments that could affect the timing of meter endpoint installations.

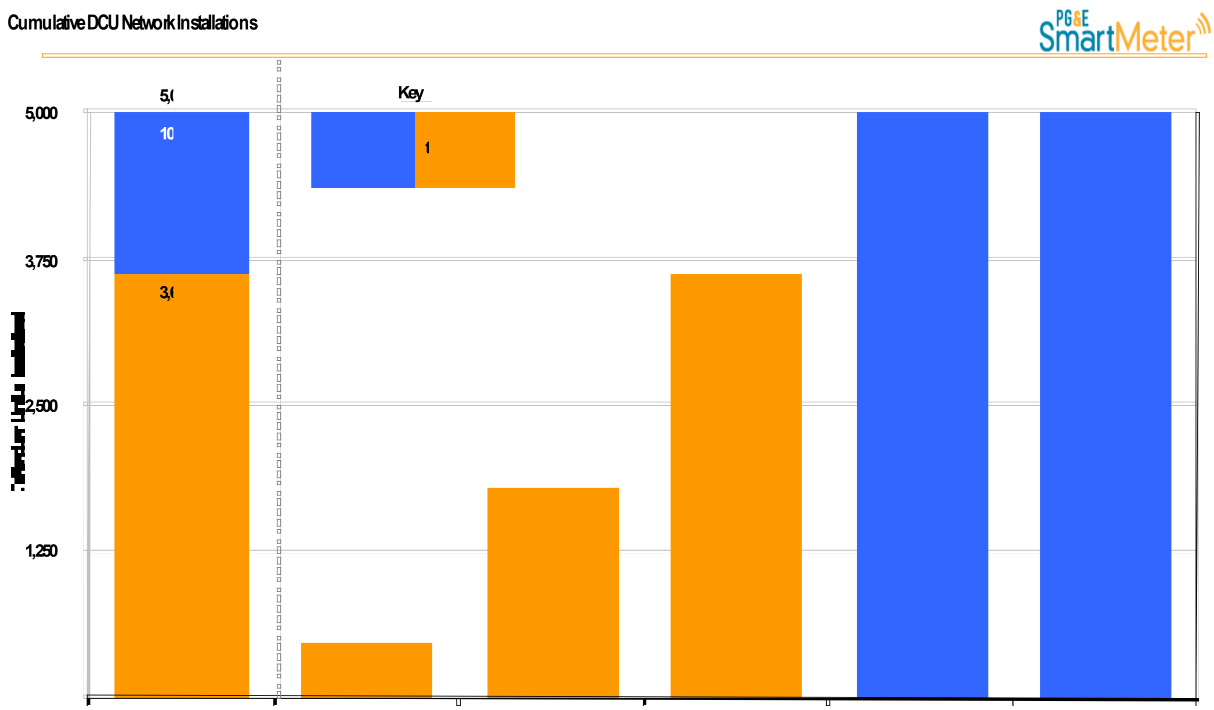
The following figures summarize the progress of PG&E's SmartMeter™ Program implementation in each respective area through December 31, 2009. The percent-of-plan refers to the total (five-year) Program completion and provides perspective on PG&E's installation progress. PG&E reports actual and projected deployments and installations on a calendar year (CY) basis.

Table III – 2



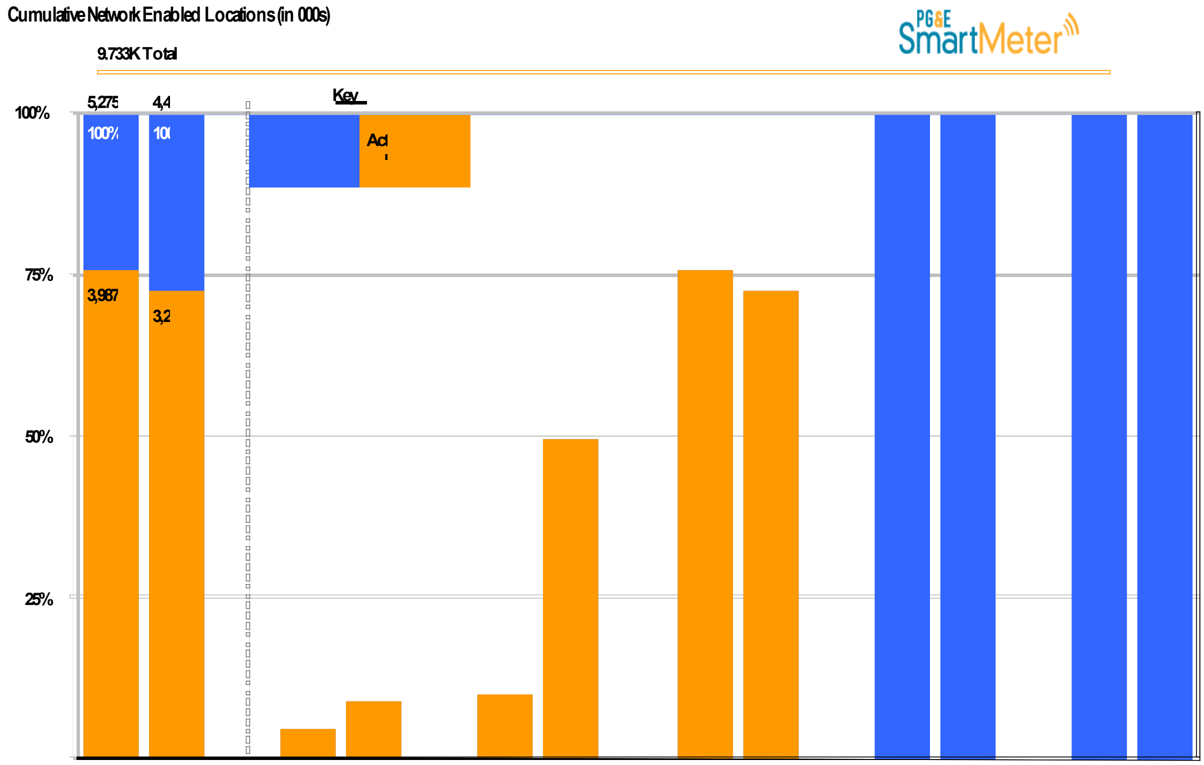
Electric Network - Substation SCE	Total	Yr 1 (to Dec-07)				
Cumulative Installed thru 12/09	51	51				
Plan	51	51				
Electric Network - RF Mesh Access Points	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Cumulative Installed thru 12/09	886	-	221	886	-	-
Plan	1,182	-	221	886	1,182	1,182

Table III - 3



Cumulative Data Collection Unit (DCU) Installations	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Installed thru 12/09	3,632	487	1,800	3,632	-	-
Plan	5,000	487	1,800	3,632	5,000	5,000

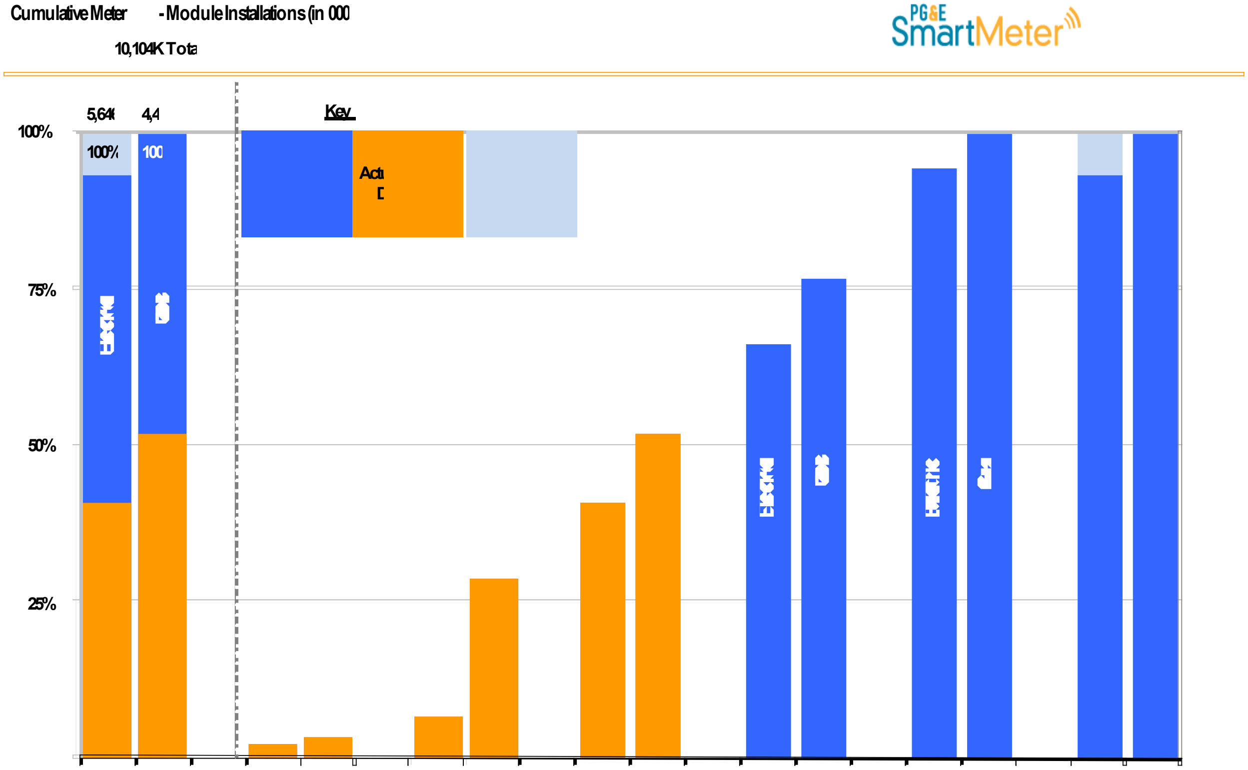
Table III - 4



Cumulative Network Enabled Locations	Total	2007		2008		2009		2010		2011	
(000)		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Enabled thru 12/09	7,226K	238K	398K	542K	2,210K	3,987K	3,238K	-	-	-	-
Plan*	9,733K	238K	398K	542K	2,210K	3,987K	3,238K	5,275K	4,458K	5,275K	4,458K

* Enabled electric network is presented on an access point basis, with prior periods on a consistent basis.

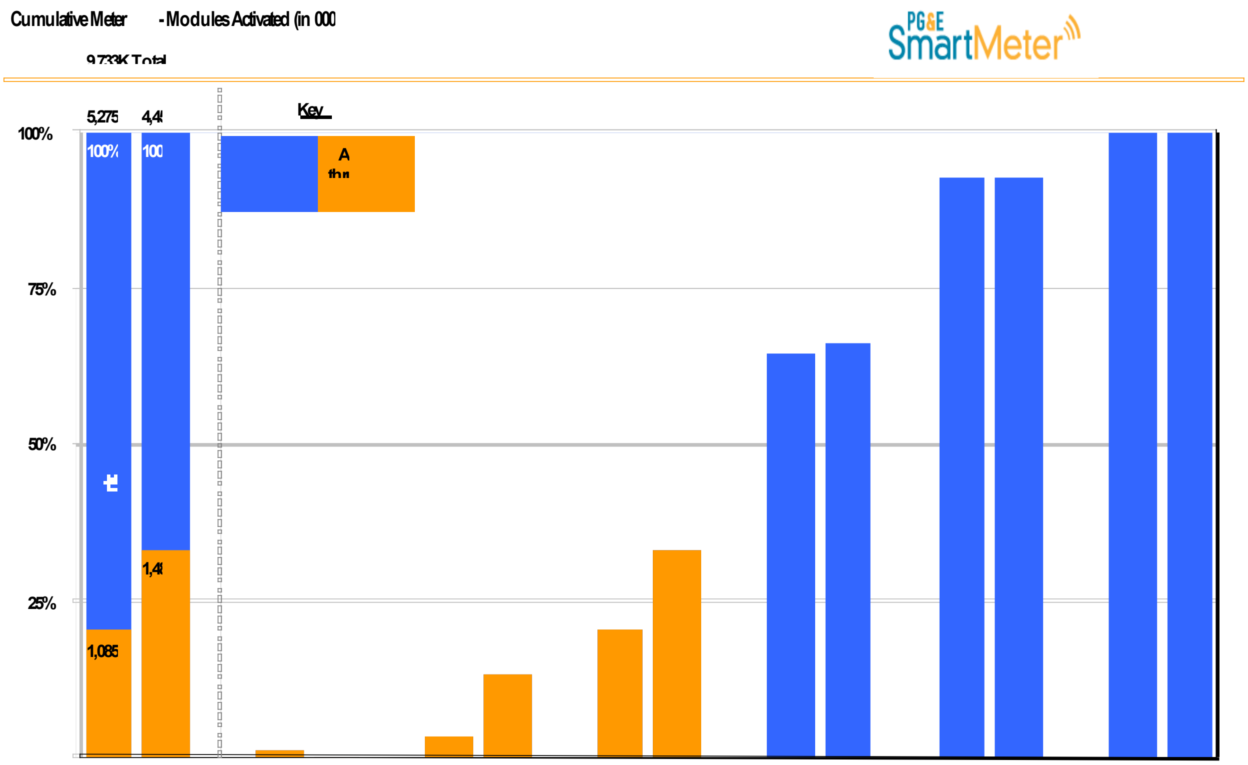
Table III - 5



Cumulative Meter-Module Installations (000)	Total	Year 1		Year 2		Year 3		Year 4		Year 5		Year 6	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Installed thru 12/09	4,616K	136K	142K	376K	1,294K	2,306K	2,310K	-	-	-	-	-	-
Plan*	10,104K	136K	142K	376K	1,294K	2,306K	2,310K	3,729K	3,423K	5,335K	4,458K	5,646K	4,458K

*Planned total includes installation of retrofitted SmartMeters™ and updated meter growth forecast through 12/31/10.

Table III - 6



Cumulative Meters Activated	Total	2007		2008		2009		2010		2011		2012	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Activated thru 12/09	2,574K	54K	24K	183K	601K	1,085K	1,489K	-	-	-	-	-	-
Plan*	9,733K	54K	24K	183K	601K	1,085K	1,489K	3,422K	2,970K	4,908K	4,135K	5,275K	4,458K

* Includes updated meter growth forecast through 12/31/10.

IV. Program Costs and Benefits

A. SmartMeter™ Program Costs

The SmartMeter™ PMO maintains governance over the allocation of both the annual budget and budget-to-completion for each of the respective workstreams. The workstreams are summarized into four major categories in this Report: Field Delivery, Information Technology, Customer & SM (SmartMeter™) Operations, and PMO.

The Program budget also includes a risk-based allowance, which was developed to provide for uncertainties and risks in cost estimates for the defined Program work scope. For the SmartMeter™ Program, only the officer-led Steering Committee can approve a workstream expenditure that requires a draw against the risk-based allowance funding category. If a draw against the risk-based allowance is approved, the workstream budget is shown with an increase in approved funds, and the risk-based allowance category with an equal offsetting amount. In addition, the PMO recommends other reallocations, both increases and decreases, within and among workstream budgets, as circumstances require. Table IV-1 indicates the approved adjustments to the workstream budgets since the July 31, 2009 Report.

Through December 31, 2009, the SmartMeter™ Program has incurred costs of approximately $1,337 million ($1,092 million in capital and $245 million in expense). Of this total dollar amount, Field Delivery activities have cost approximately $806 million (60 percent) and IT-related activities have cost approximately $384 million (29 percent). The remaining 11 percent is attributed to the Customer & SM Operations and PMO categories. The Program's authorized cost is based on the combined project cost authorization of the AMI and Upgrade Decisions.

Table IV - 1

($ Millions)	TOTAL	Field Delivery	Information Technology	Customer & SM Operations	PMO	Risk-Based Allowance*
Total Plan at Completion	2,206	1,524	222	191	92	178
Risk-Based Allowance Draw: May 07	-	-	3	-	-	(3)
June '09 Budget	2,206	1,524	225	191	92	175
June 2009 Forecast	-	-	-	-	-	-
Cost Adjustments	109	(47)	131	(3)	29	-
Subtotal	2,315	1,476	356	187	120	175
Potential Use of Risk-Based Allowance	(109)	-	-	-	-	(109)
June '09 Total Plan	**2,206**	**1,476**	**356**	**187**	**120**	**66**
December 2009 Forecast	-	-	-	-	-	-
Cost Adjustments	47	(38)	127	(32)	(10)	-
Subtotal	2,253	1,438	483	156	111	66
Potential Use of Risk-Based Allowance	(47)	-	-	-	-	(47)
December '09 Total Plan	**2,206**	**1,438**	**483**	**156**	**111**	**19**
Actuals	**1,337**	**806**	**384**	**70**	**77**	**N/A**
% of Plan	61%	56%	80%	45%	70%	

* Represents $3 million of draw and $156 million of potential use

Note: Totals subject to rounding

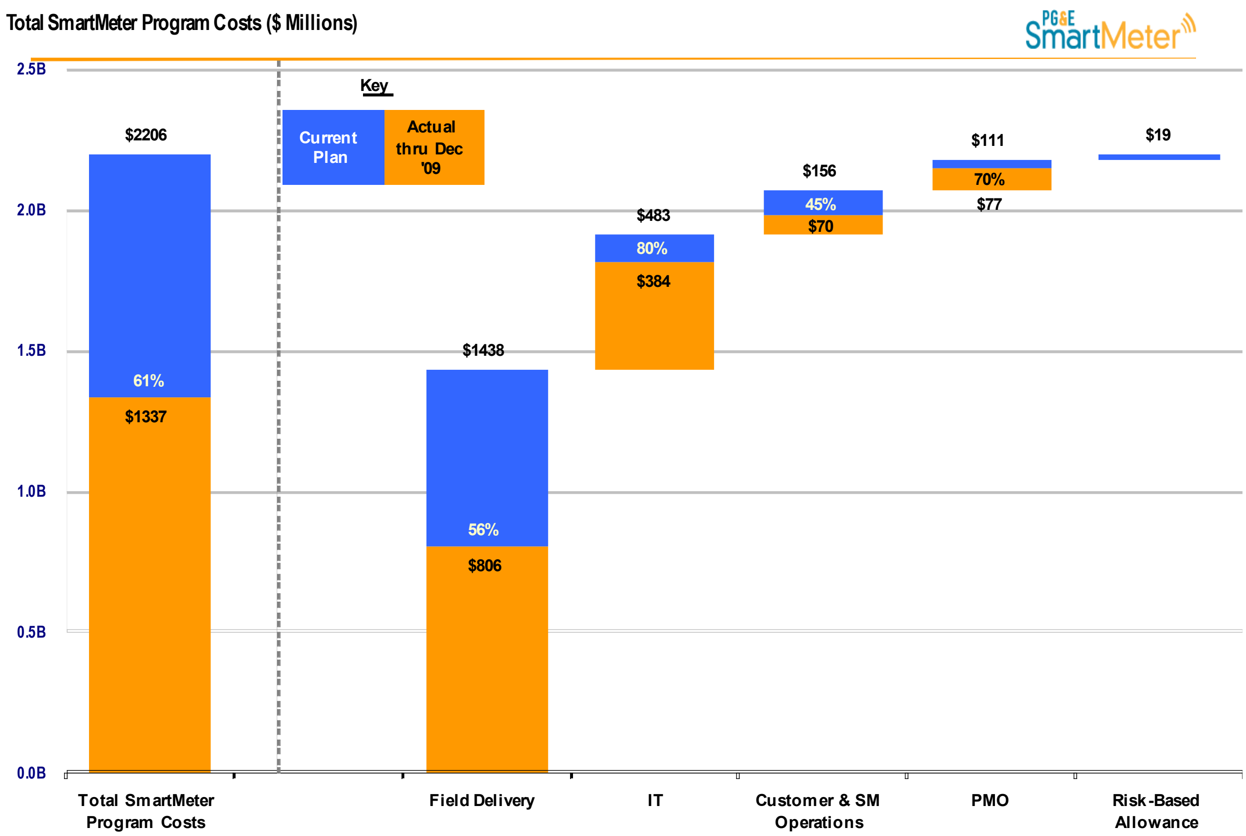
The Customer & SM Operations category includes $54.8 million specifically authorized in the AMI Decision for the purpose of marketing Critical Peak Pricing programs. As of December 31, 2009, approximately $14.8 million of the $54.8 million has been spent in support of SmartRate marketing efforts from inception to date.

(Thousands of Dollars)	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	Total
SmartRate Marketing & Education and Customer Web Presentment	**$ 0**	**$ 349**	**$1,166**	**$6,811**	**$6,454**	**$14,780**

Tables IV-2 through IV-7 show PG&E's incurred costs since inception through December 31, 2009, for the SmartMeter™ Program, as well as each respective budget category. The percent-of-expenditures refers to the total incurred expenditure as of December 31, 2009 as a percentage of the adjusted budgets.

In December 2009, the Energy Division requested that PG&E provide a mapping of its SmartMeter™ Program budget line items to the cost categories contained in Table 1 of the AMI Decision in its monthly and semi-annual reports. Table IV-8 shows this mapping.

Table IV - 2

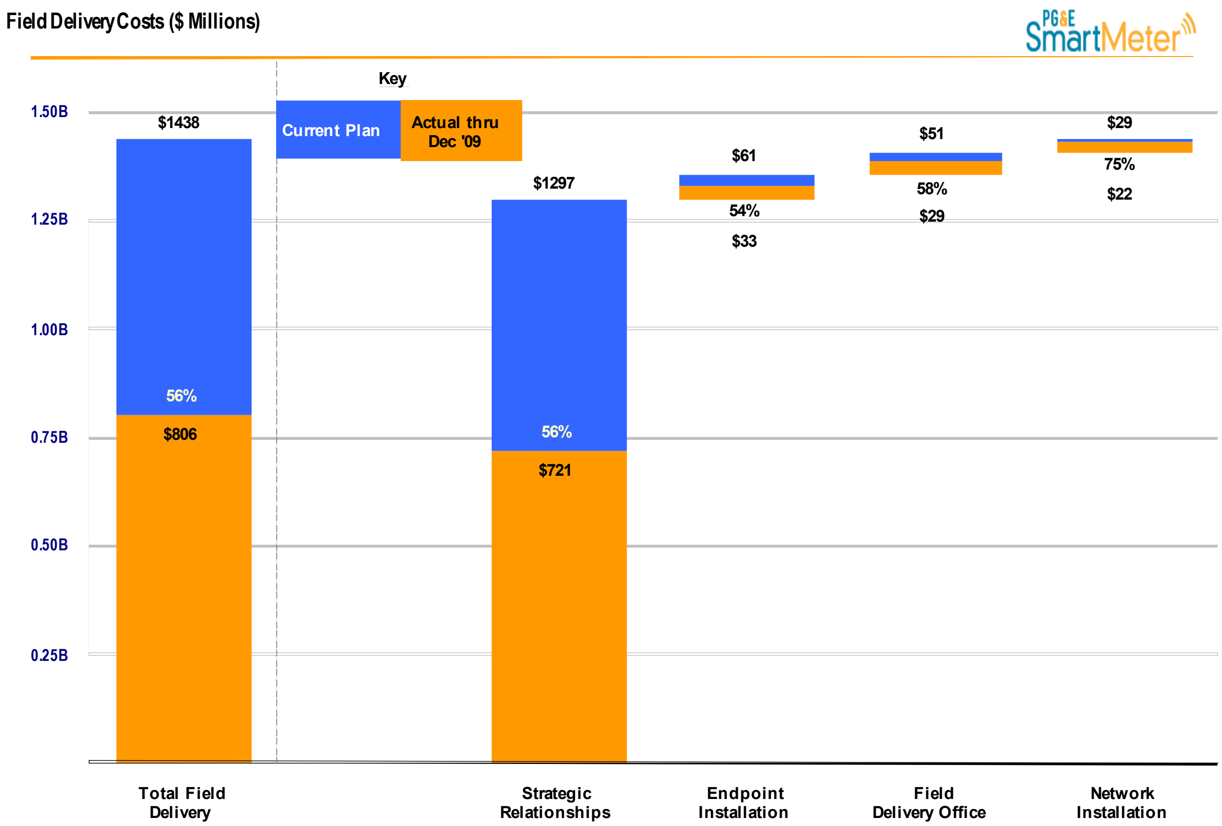


$ Millions	Total SmartMeter Program Costs		Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allow ance
Actual thru 12/09	$	1,337	806	384	70	77	N/A
Plan as of 6/09*	$	2,206	1,476	398	146	120	66
Cost Changes/Reallocation	$	0	(38)	85	10	(10)	(47)
Plan as of December 31, 2009	$	2,206	1,438	483	156	111	19
% of Plan completed	61%		56%	80%	45%	70%	

* Changes in planned amounts from the July '09 report are a result of an organizational restructuring completed during the second half of 2009.

Note: Totals subject to rounding

Table IV - 3



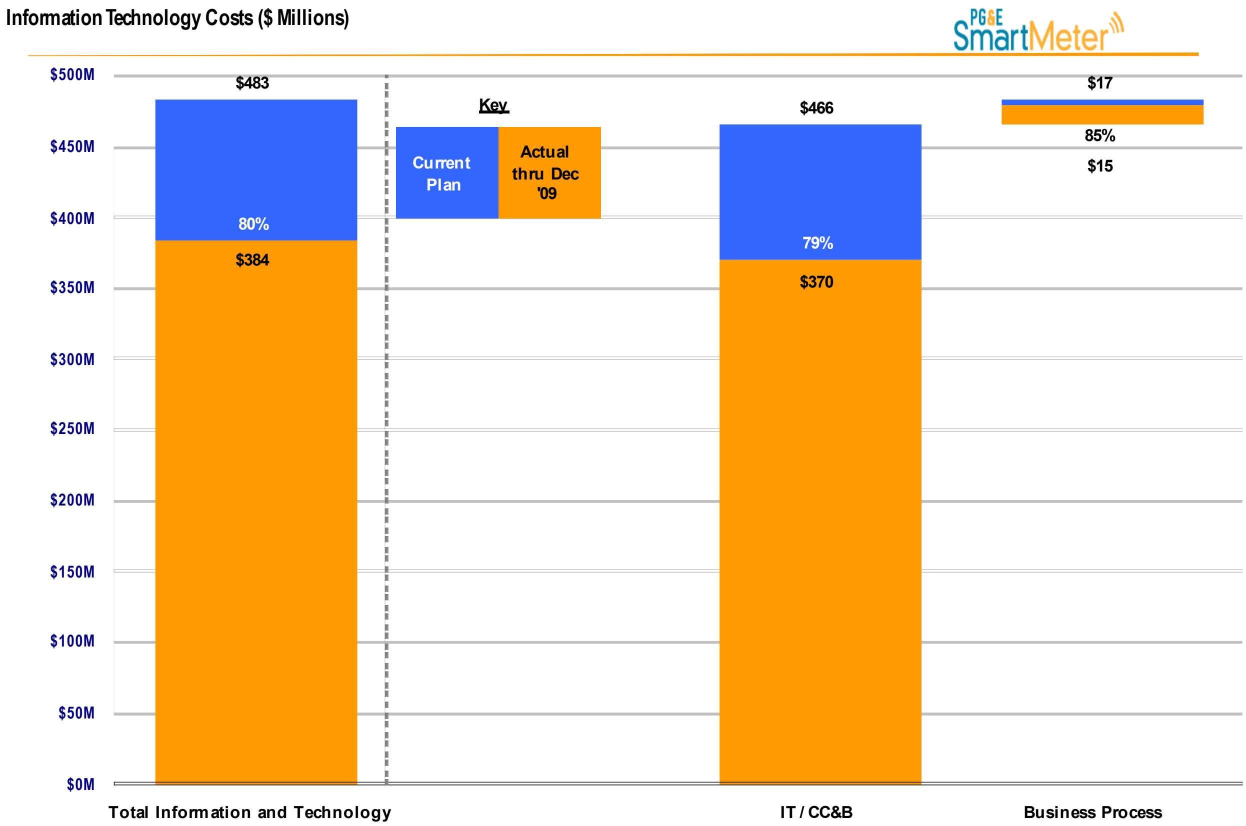
$ Millions	Total Field Delivery	Strategic Relationships	Endpoint Installation	Field Delivery Office	Netw ork Installation
Actual thru 12/09	$ 806	721	33	29	22
Plan as of 06/09*	$ 1,476	1,122	256	74	25
Cost Changes/Reallocation	$ (38)	175	(195)	(23)	4
Plan as of December 31, 2009	$ 1,438	1,297	61	51	29
% of Plan Expended	56%	56%	54%	58%	75%

$ Millions	Netw ork Installation	Electric Netw ork	Gas Netw ork
Actual thru 12/09	$ 22	13	9
Plan as of 06/09*	$ 25	17	8
Cost Changes/Reallocation	$ 4	3	1
Plan as of December 31, 2009	$ 29	19	10
% of Plan Expended	75%	66%	92%

* Changes in planned amounts from the July '09 report are a result of an organizational restructuring completed during the second half of 2009.

Note: Totals subject to rounding

Table IV - 4



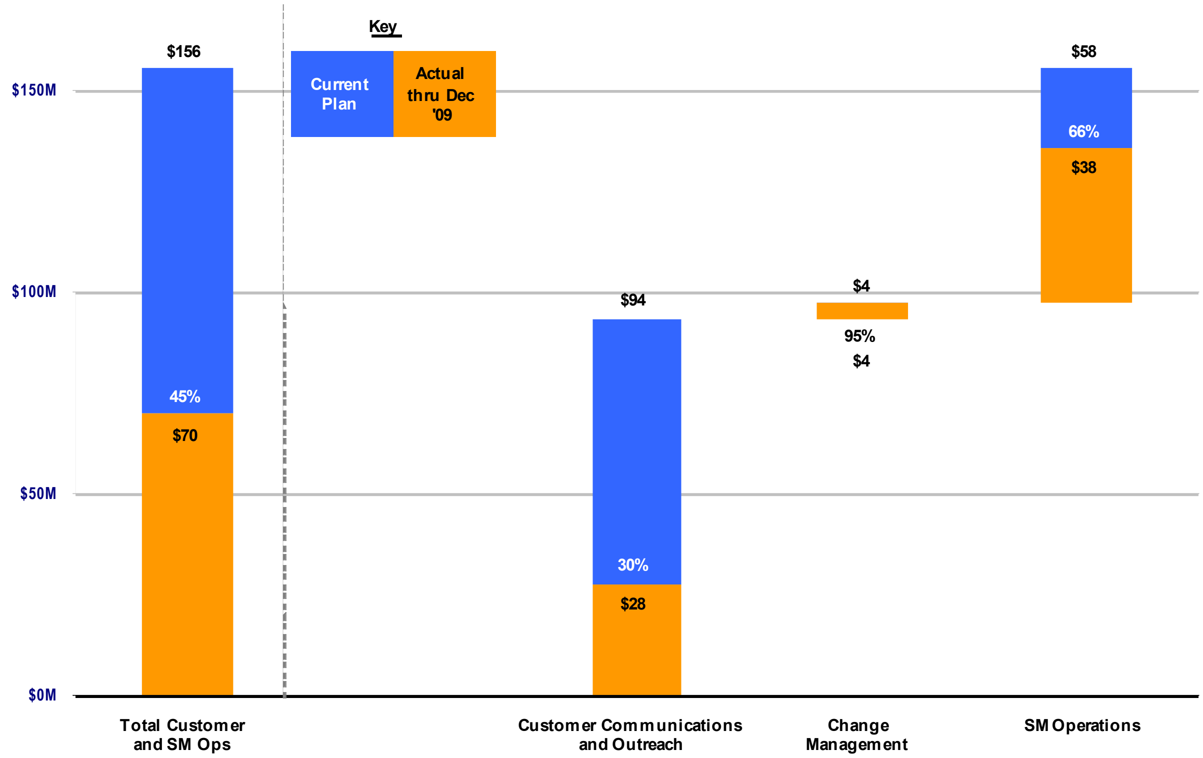
$ Millions	Total Information and Technology	IT / CC&B	Business Process
Actual thru 12/09	$ 384	370	15
Plan as of 6/09*	$ 398	398	-
Cost Changes/Reallocation	$ 85	68	17
Plan as of December 31, 2009	$ 483	466	17
% of Plan Expended	80%	79%	85%

* Changes in planned amounts from the July '09 report are a result of an organizational restructuring completed during the second half of 2009.

Note: Totals subject to rounding

Table IV - 5

Customer and SM Operations Costs ($ Millions)



$ Millions	Total Customer and SM Ops	Customer Communications and Outreach	Change Management	SM Operations
Actual thru 12/09	$ 70	28	4	38
Plan as of 6/09*	$ 146	83	-	62
Cost Changes/Reallocation	$ 10	10	4	(4)
Plan as of December 31, 2009	$ 156	94	4	58
% of Plan Expended	45%	30%	95%	66%

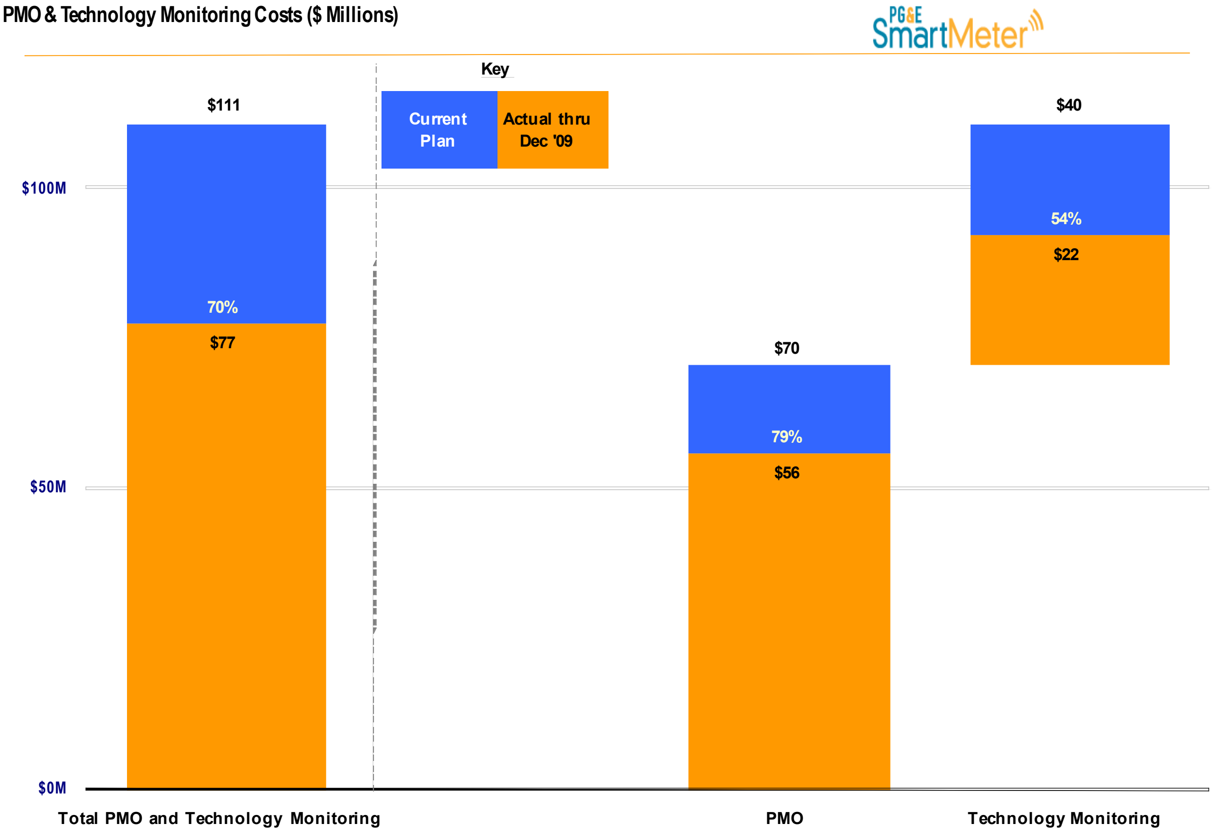
* Changes in planned amounts from the July '09 report are a result of an organizational restructuring completed during the second half of 2009.

Wider change management activities, essential to the deployment of new IT functionalities and business processes supporting completion of system-wide deployment including urban areas, are in process of further assessment and estimation.

Note: Totals subject to rounding

Table IV - 6

PMO & Technology Monitoring Costs ($ Millions)



$ Millions	Total PMO and Technology Monitoring	PMO	Technology Monitoring
Actual thru 12/09	$ 77	56	22
Plan as of 6/09	$ 120	91	29
Cost Changes/Reallocation	$ (10)	(21)	11
Plan as of December 31, 2009	$ 111	70	40
% of Plan Expended	70%	79%	54%

* Changes in planned amounts from the July '09 report are a result of an organizational restructuring completed during the second half of 2009.

Note: Totals subject to rounding

Table IV - 7

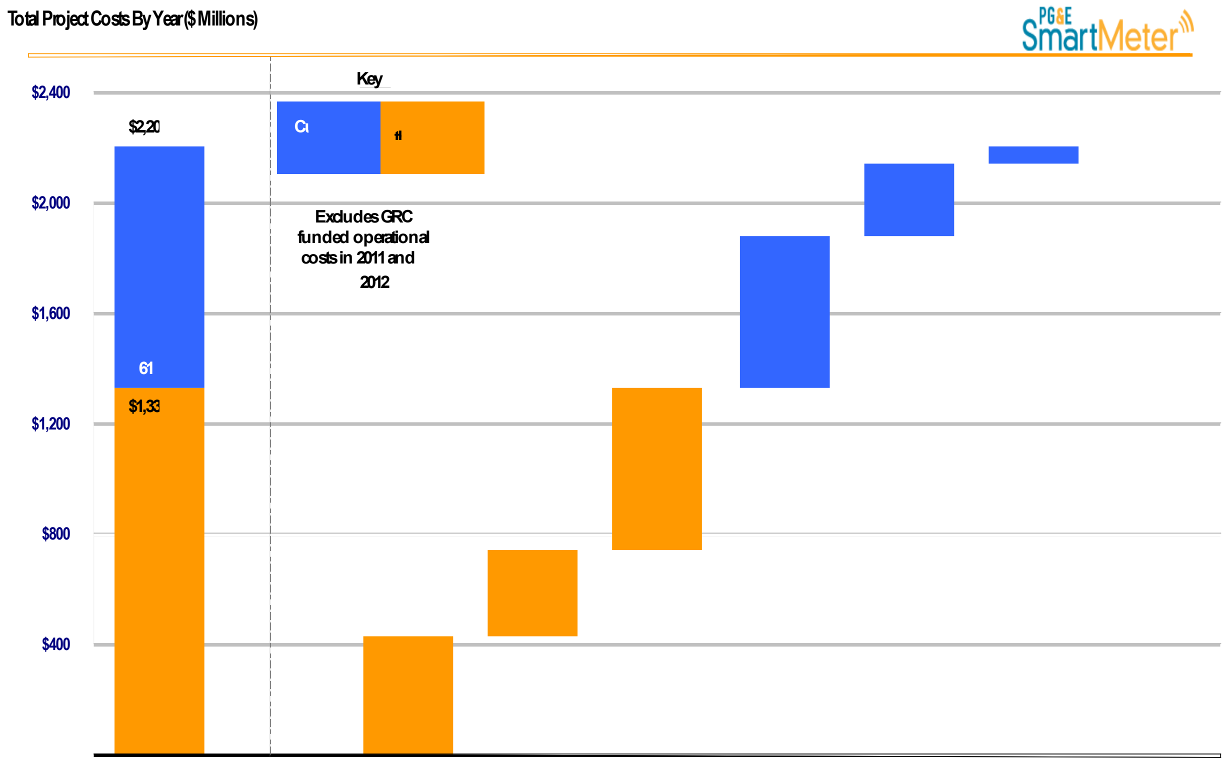


Table IV - 8

#	Workstream	D.06-07-027 Cost Category Line Item Number
1	PMO	1
2	SM Operations	5, 8, 9, 10, 11, 12, 14
3	Customer Communications & Outreach	13, 15, 16
4	Change Management	1, 15
5	Field Delivery - Strategic Relationships	3, 4, 8, 9
6	Field Delivery - Endpoint Installation	8, 12
7	Field Delivery - Field Delivery Office	1, 5, 8, 9, 11
8	Field Delivery - Network Installation	9, 10
9	*(Calculation Line For Monthly Report)*	
10	Business Process	6
11	IT/CC&B	4, 5, 6, 7, 16,18
12	Technology Monitoring	1,18
13	Unassigned Spending	2

Note: Technology Monitoring was not included as a cost category in D.06-07-027. This category was added in the SmartMeter Program Upgrade decision.

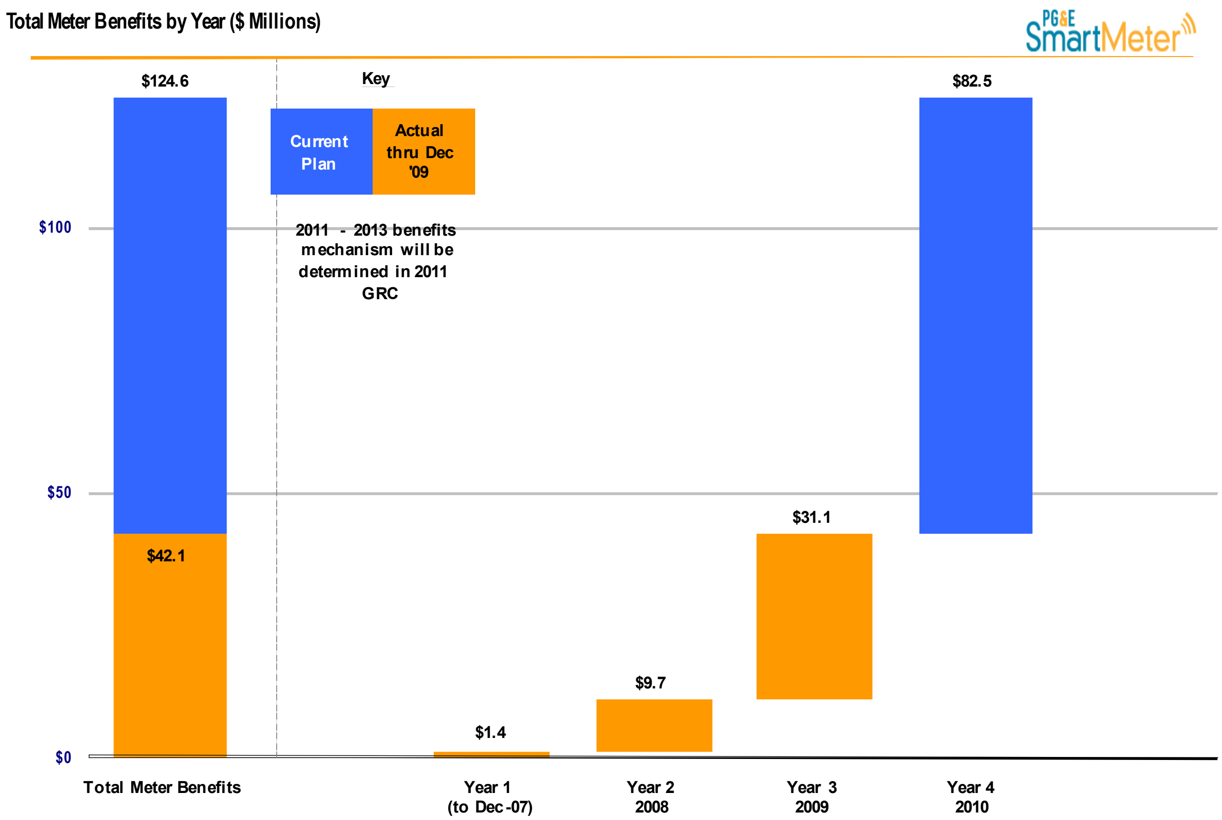
Operational Benefits Realization

Program benefits are primarily realized after meters fitted with SmartMeter™ technology are installed, can be read remotely over the communications network, and become activated. Activation of gas and electric meters cannot occur until: (1) the communications network infrastructure is in place to remotely read them, (2) the meters are installed with a network communications device and are confirmed, (3) the remote meter reads become useable for billing purposes; and (4) enough customers have been converted to SmartMeter™ billing within a given geographical area to service a "route string" currently being read by a meter reader over the course of a month.

As reported in the January 2008 Report, the first meter activations occurred in December 2007. Since then, approximately 2,574,000 meters have been activated as of December 31, 2009. Total cumulative benefits recorded as credits to the balancing accounts as of December 31, 2009 are $42.1 million, which represent both activated meter benefits and mainframe software licensing benefits. Such amounts are consistent with the calculation methodologies and savings rates adopted in the final CPUC Decisions.

Table IV-9 shows the currently forecasted plan for activated meters and the corresponding benefits based on the average savings rates adopted in the AMI and Upgrade Decisions. These benefits include $1.9543 per meter per month for electric and $1.0366 per meter per month for gas.

Table IV – 9



Activated Meter Benefit - Current Forecast (As of December 31, 2009)

(in thousands)		Year 1* (To Dec-07)	Year 2* (CY 2008)	Year 3* (CY 2009)	Year 4 (CY 2010)
Meters					
Activated Electric meter months		50	1,436	6,669	25,843
Activated Gas meter months		21	2,086	12,666	26,023
Total Activated meter months		71	3,521	19,335	51,866
SmartMeter Balancing Account					
Electric at $1.77 per meter month	$1.77	$89	$2,544		
Electric at $1.95 per meter month	$1.95			$12,925	$50,503
Gas at $1.04 per meter month	$1.04	$22	$2,162	$13,129	$26,975
Reduced Software Licensing		$1,251	$5,000	$5,000	$5,000
Automate Interval Billing		-	-	-	
		$1,362	$9,706	$31,054	$82,478

** Actuals*

Note: Totals subject to rounding

V. System Performance Criteria

System performance criteria and metrics are measured and reported on an on-going basis as meter installations progress. PG&E may modify these criteria and metrics after it has collected and analyzed actual system performance parameters in order to better characterize system performance, although no such changes have been made to these criteria at this time.

The performance criteria presented in Table V-1 are based on the amount of actual reads retrieved by the system versus the expected number of reads provided by the head-end system. Deployment in areas with poor cellular coverage degrades performance, while firmware upgrades and supplemental network designs for existing and new installations improve performance. Since the last Report, the deployment volume continues to increase, electric failure rates have increased, while gas failure rates have declined. PG&E considers that the system performs as designed within the specified system requirements. Additionally, PG&E's monitoring of SmartMeter™ billing continues to indicate performance that meets and/or exceeds established criteria.

Table V - 1

Performance Criteria	Performance from Jul. '09 thru Dec. '09	Performance from Jan. '09 thru Jun. '09	Performance from Jul. '08 thru Dec. '08
1. Electric module failure rate	0.34%	0.12 %	0.05 %
2. Gas module failure rate	0.36%	0.45 %	0.05 %
3. Electric network failure rate	0.63%	0.29 %	0.35 %
4. Gas network failure rate	0.34%	0.24 %	0.20 %
5. Electric billing data collection failure rate	1.14%	0.81 %	0.75 %
6. Gas billing data collection failure rate	0.24%	0.20 %	0.13 %

Definitions of System Performance Criteria Terms:

Electric module failure rate: The number of installed electric modules that failed divided by the total number of electric modules installed at customer locations.

Gas module failure rate: The number of installed gas modules that failed divided by the total number of gas modules installed at customer locations.

Electric network failure rate: The number of installed electric network key component parts that failed divided by the total number of installed electric network key component parts.

Gas network failure rate: The number of installed gas network collectors (DCUs) that fail (excluding battery replacements) divided by the total number of installed gas network collectors.

Electric billing data collection failure rate: The number of electric SmartMeters™ from which complete data was not retrieved, divided by the total number of electric SmartMeters™.

Gas billing data collection failure rate: The number of gas SmartMeters™ from which a daily cumulative read was not retrieved, divided by the total number of gas SmartMeters™.

VI. Customer Interest in Accessing Real-Time Usage and Pricing Information

Based on customer feedback that PG&E received over the past year, several improvements are being made to expand the tools available for customers to access, understand, and use information about their energy use to control their costs. PG&E is developing a program that will be available to SmartMeter™ customers that will allow them to receive notifications via phone call, e-mail, or text message, as they pass through the tiers of electric use to let them know when they are paying higher prices for energy use. PG&E is also making improvements to the tools available online at www.pge.com/myaccount for SmartMeter™ customers so that pricing information is more accessible and relevant when viewing information about daily and hourly energy use. These improvements include assigning approximate dollar amounts to intervals of energy use and providing an approximate cumulative dollar amount to date in a customer's billing cycle for energy use. These new SmartMeter™-enabled tools will be communicated to customers in 2010 in SmartMeter™ outreach materials, and integrated into PG&E's other programs available to customers to ensure that customers know all the tools available to them to understand and control their energy use.

PG&E's SmartRate Program (a critical peak pricing tariff option that requires interval data to administer) was launched in May 2008. It supports a customer's ability to manage energy usage during hot summer days when SmartDay[8] events are triggered (based on temperature thresholds). In 2009, PG&E called fifteen SmartDay events: June 29, June 30, July 13, July 14, July 16, July 21, July 27, August 10, August 11, August 18, August 27, August 28, September 2, September 10, and September 11. As of December 31, 2009, 30,498 customers were active SmartRate Program participants (including 25,428 residential and 172 commercial customers).

PG&E has made changes to the SmartRate marketing processes for the 2010 season building on the 2009 strategy. In order to learn how to most efficiently engage customers, a number of different variables were tested under direct mail:

- PG&E tested personal messaging (based on information from PG&E's Customer Segmentation and Analytics database) focused on audience segments with certain characteristics (community oriented, conservation oriented, etc.) in order to maximize potential message impact .
- PG&E tested the format of the mailing (a letter in a standard sized envelope versus a more promotional appearing self-mailer) to see which garnered a better

[8] See footnote 6.

customer response. The results showed that personal messaging performed better than generic program messaging and the letter pack performed better than the self mailer.

In 2010 PG&E plans to combine both the letter pack and the personal messaging in an effort to further increase customer response.

PG&E's data from recent SmartRate Experience Tracking Studies fielded among residential SmartRate customers both in Bakersfield (talking with 501 second-season SmartRate customers who enrolled in 2008) and in new areas (talking with 560 2009 SmartRate participants following SmartMeter™ rollout) suggest the following:

- SmartRate customers are primarily motivated by saving money/reducing their bill.
- Turning off and/or unplugging appliances is the most prevalent behavior change. Additionally, air conditioner (AC) usage behaviors appear different between the two customer groups; new customers appear more likely to shut off their AC, while second-year customers are more likely to simply turn their thermostats up.
- The majority of SmartRate customers have a positive reaction regarding their behavior changes during SmartDay events, with second-year SmartRate customers feeling slightly more positive about their experience than new SmartRate customers.
- A significant percentage of SmartRate customers communicate they *have changed their behavior "on SmartDays and on additional days"* (84 percent of Bakersfield and 78 percent of new customers agree with this statement).
- SmartRate customers are very satisfied with the program and a majority plan to continue on SmartRate.

- A majority of SmartRate customers (71 percent of Bakersfield and 72 percent of new customers) state that they would continue on SmartRate if it was changed to a year-round plan.

Overall, customers seem to be satisfied with SmartRate, particularly so with the Bakersfield second-year customer group. Early indications are that customers who stay with SmartRate become more accustomed to the behavior changes required, are more satisfied with the rate plan, find it somewhat easier to respond to SmartDays, and tend to extend their energy-reducing/shifting behaviors into non-SmartDays more often than newer customers.

The SmartRate Program provides bill protection during the first full summer of the customer’s participation. Under bill protection, if a customer pays more under the SmartRate Program than the customer would have paid on the otherwise applicable rate schedule, the difference is reimbursed to the customer on the November bill following the first full summer of participation in the program. Beginning May 1, 2010, approximately 7,578 of the residential SmartRate customers will lose bill protection. These customers have completed one full summer season on SmartRate, have had the opportunity to test the program, and will no longer be eligible to receive bill protection. Bill protection warning letters will be mailed beginning February 2010 and again in May 2010 informing SmartRate customers of this change. Customers will be given the option to de-enroll from the SmartRate program if they feel they will not benefit from it.