Pacific Gas and Electric Company
Advanced Metering Infrastructure Semi-Annual Assessment Report
SmartMeter™ Program Quarterly Report
September 2011

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

September 28, 2011

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I. Executive Summary

A. Introduction

This is Pacific Gas and Electric Company's (PG&E or the Company) tenth 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 ninth quarterly report for the SmartMeter™ Program Upgrade.

In Decision 06-07-027 (the AMI Decision), the California Public Utilities Commission (CPUC or Commission) approved the SmartMeter™ Program that PG&E 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 (the Upgrade Application) to recover incremental costs associated with the SmartMeter™ Program.

Ordering Paragraph 16 of the AMI Decision requires that PG&E provide a semi-annual report assessing AMI deployment. Ordering Paragraph 7 of the Upgrade Decision requires that PG&E provide quarterly reports on the implementation progress of the SmartMeter™ Upgrade. 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

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

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. Update on 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 during the first six months of 2011.

1. Advances in AMI Technology

PG&E continues to monitor metering and network collector technologies as the AMI-industry advances. In addition, PG&E continues to identify and approve engineering solutions using specific technologies and products that enable PG&E to deploy SmartMeters™ in difficult-to-reach meter locations such as urban areas and remote locations. These solutions may require existing network communication technologies or other technologies not yet available, as conditions dictate.

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

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

2. Progress in PG&E's AMI Deployment

PG&E continues to deploy solid-state electric meters communicating over a radio frequency (RF) mesh network, and gas modules communicating over an RF network, throughout the service territory. The deployment of the RF Mesh network was planned to consist of an initial phase to deploy 1,553 Access Points (APs) at defined locations throughout PG&E's service territory, followed by subsequent phases to deploy additional APs to strengthen the network where required. As of June 30, 2011, 1,375 APs have been installed throughout the PG&E service territory. Installation efforts continue on the gas RF network, with a total of 4,759 data collection units (DCUs) installed through June 30, 2011. This number represents approximately 95 percent of an estimated total population of 5,000 DCUs at project completion.

As of June 30, 2011, approximately 8,570,000 meters (approximately 4,685,000 electric and 3,885,000 gas) have been converted to, or replaced with, SmartMeter™ technology, representing approximately 85 percent of the total PG&E meter population. Of this number, approximately 4,614,000 meters were "activated" and the benefits adopted in the 2011 GRC Decision 11-05-018 were recorded to the gas and electric SmartMeter™ balancing accounts. Further details of the SmartMeter™ Program's deployment status are provided in Section III of the Report.

PG&E has continued to expand and enhance customer outreach activities to address customers' concerns about SmartMeter™ technology. These activities include increased customer contacts before, during, and after deployment through direct mail, mass media, online content, and community outreach events. PG&E has also initiated a Customer Experience survey, surveying thousands of residential and business customers each quarter.

In addition to the outreach activities, meter testing continues with accuracy tests at the manufacturer factories, random sample testing performed by PG&E at its Fremont Meter Shop, and field testing at customer premises. PG&E will field-test any SmartMeter™ device upon customer request, and PG&E offered side-by-side testing of customers' SmartMeters™ with conventional meters. As of June 30, 2011, 330 side-by-side (dual socket) tests were completed.

3. Program Costs and Benefits

In late 2010 and early 2011, the PMO completed a detailed review of all workstream forecasts. The Program sought and received approval in February 2011 from PG&E's Board of Directors to incur an additional $129 million in costs to complete the scope of the project. As a result, the Program is now expected to exceed the CPUC-authorized cost cap. As reported in its financial disclosures, PG&E recorded a reserve of $36 million, representing the current forecast of capital-related costs that are expected to exceed the CPUC-authorized cost cap and therefore will likely not be recoverable through rates. PG&E will continue to update its forecasts as the Program continues and may incur additional non-recoverable costs.

As of June 30, 2011, PG&E had allocated all of the $2,355 million Board-authorized project amount to Program workstreams, and continued to monitor the actual spending against the forecast, as well as issues and risks that could contribute to cost overruns. SmartMeter™ Program expenditures through June 30, 2011 totaled approximately $2,143 million (92 percent) of the $2,355 million.

In 2010, as recommended by PG&E's SmartMeter™ Steering Committee, the $178 million risk-based allowance authorized by the Commission was allocated to workstream budgets based on actual and forecasted costs.

As previously noted, the total number of activated meters on June 30, 2011 was approximately 4,614,000. The related benefit savings credited to the SmartMeter™ Balancing Accounts (SBA - Gas, and SBA - Electric) through this same date totaled $115.5 million. These amounts are consistent with the method for calculating and recording benefits provided in PG&E testimony and in both the AMI and Upgrade Decisions. Further details of the SmartMeter™ Program's cost and benefit status are detailed in Section IV of this report.

4. System Performance Criteria

System performance metrics are provided in Table V-2. Since early 2010, PG&E has publicly reported on system performance on its website (accessed at the following link: (http://www.pge.com/myhome/customerservice/meter/smartmeter/programdata/) At this website, PG&E's SmartMeter™ Program provides metrics on deployment, billing performance, system performance, meter accuracy testing, and customer data usage.

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

PG&E launched its SmartRate™ Program in May 2008. In the first half of 2011, PG&E called two SmartDay™ events. As of June 30, 2010, the SmartRate™ Program had 22,930 active residential customers. Details of the SmartRate™ Program are provided in Section VI of this Report.

6. SmartMeter™ Information Technology Progress

During the first half of 2011, 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 PG&E's continuing IT development over the past six months are provided in Section VII of this Report.

7. SmartMeter™ Transition to Operations

Beginning in 2011, those SmartMeter™ Program activities that are of a recurring nature (i.e., activities that will continue after the Program has been completed) began to transition from the Program to PG&E's traditional operations organizations. To support this upcoming transition, PG&E has initiated significant employee outreach and change management activities to address employee education. Details are provided in Section VIII of this Report.

8. Other Program Updates

Lastly, Section IX of this report provides three other updates on the SmartMeter™ Program:

- PG&E submitted an application to the CPUC that, if approved, would modify the SmartMeter™ Program to enable any residential customer to have PG&E turn off the radios in their gas and/or electric SmartMeters™.
- The California Council on Science and Technology (CCST) issued its final report concluding that the RF signals from SmartMeters™ pose no known health risks.
- PG&E announced that it discovered a defect in approximately 1,600 of the two million electric SmartMeters™ that Landis + Gyr (L+G) supplied to it. These meters were subsequently replaced by PG&E and all affected customers were made whole, provided $25 inconvenience credits, and offered home energy audits. If any additional L&G meters are found to be defective, the meters will be replaced as well.

II. Advances in AMI Technology

A. Introduction

The AMI industry has continued to grow along with progress in Smart Grid – Distribution Automation (DA). On June 30, 2011, PG&E submitted its Smart Grid Deployment Plan to the CPUC and is organizing projects including the use of AMI communications network to support DA applications, including automated distribution reconfiguration and load control. The CPUC is also continuing to encourage development of Home Area Network (HAN) functionality.

B. PG&E Distribution Automation Update

In its July 2009 Report, PG&E noted its evaluation of both the implementation of Communicating Faulted Circuit Indicators (CFCI) and commercial auto-reconfiguration system. PG&E's Smart Grid plans reflect the current implementation of the commercial auto-reconfiguration systems and further examination of powerline and fault sensor technology.

C. PG&E's HAN Update

Development of PG&E's HAN enablement road map is in progress. In Decision 11-07-056, the Commission ordered PG&E and the other California electric utilities to file HAN "rollout" implementation plans by the end of November 2011, including an initial phase rollout of up to 5,000 HAN devices by March 1, 2012. PG&E's HAN Implementation Plan will describe the capabilities and schedule for PG&E's HAN-enabled programs, including discussion of how standards development and market adoption will affect the plan.

In the SmartMeter™ Upgrade Decision, PG&E was granted $6.0 million in laboratory and product demonstration costs, with the condition that PG&E can only use those ratepayer-provided funds to the extent that it matches them with funds from other sources[3]. PG&E has identified approximately $627,000 in matching funds (within technology assessment areas) and is actively working to secure the remainder of the matching funds.

D. Technology Industry Updates

PG&E continues to lead and participate in industry activities related to advanced metering and communication networks, including through membership in professional organizations and attendance at conventions and trade shows.

In February 2011, PG&E delivered presentations at DistribuTECH, the utility industry's leading Smart Grid conference and exposition. The conference covered automation and control systems, energy efficiency, demand response, renewable energy integration, advanced metering, transmission and distribution system operation and reliability, power delivery equipment and water utility technology.

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

- UCA[4] Open Smart Grid Technical Committee (Chair) – Providing oversight over UCA's systems, communications, security, simulations, and certification and testing working 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.

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

[4] The UCA® International Users Group is a not-for-profit corporation consisting of utility user and supplier companies that is dedicated to promoting the integration and interoperability of electric/gas/water utility systems through the use of international standards-based technology.

- 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 for technology alliances.
- UCA Utili ENT – Setting standards for the AMI Enterprise.
- UCA Utili SEC – Establishing open security standards for the Smart Grid.
- UCA Open 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.
- NIST SmartGrid Architecture Committee – Creating and refining a conceptual reference model, including lists of the standards and profiles, necessary to implement the vision of the Smart Grid.

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.

In 2011, there were a number of significant industry deployments, including major AMI rollout announcements by British Columbia Hydro, Baltimore Gas and Electric Company, CPS Energy, Texas New Mexico Power, and Southern California Gas

Company. Vendors supporting these projects include Itron, SSN, Smart Synch, and Aclara.

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 access to customer premises to make the necessary changes at each service location. Deployment planning adjustments may be required due to several factors – including customer considerations, supply chain constraints, labor availability, and technology considerations – which could affect the scheduling of meter endpoint installations.

B. Infrastructure Installations

As of June 30, 2011, PG&E had installed approximately 8.6 million meters (including retrofits) with SmartMeter™ technology. As noted above, the Upgrade Decision approved PG&E's plan to replace all electric meters that do not possess Upgrade technology, and PG&E has deployed 362,856 retrofit endpoints to replace PowerLine Carrier endpoints. PG&E's progress as of June 30, 2011 is summarized in Table III-1.

Table III - 1

AMI Project Status as of June 30, 2011

Progress Toward Completion	Total Budgeted Plan	Actual	% of Total Project Plan Installed
Electric Network - RF Network	1,553	1,375	89%
Gas Network Collectors	5,000	4,759	95%
Electric Network Enabled Locations	5,260,391	4,657,461	89%
Electric Meter Installations*	5,630,886	4,684,927	83%
Electric Meters Activated	5,260,391	2,242,483	43%
Gas Network Enabled Locations	4,449,040	4,234,596	95%
Gas Meter-module Installations	4,449,040	3,885,155	87%
Gas Meter-modules Activated	4,449,040	2,371,873	53%

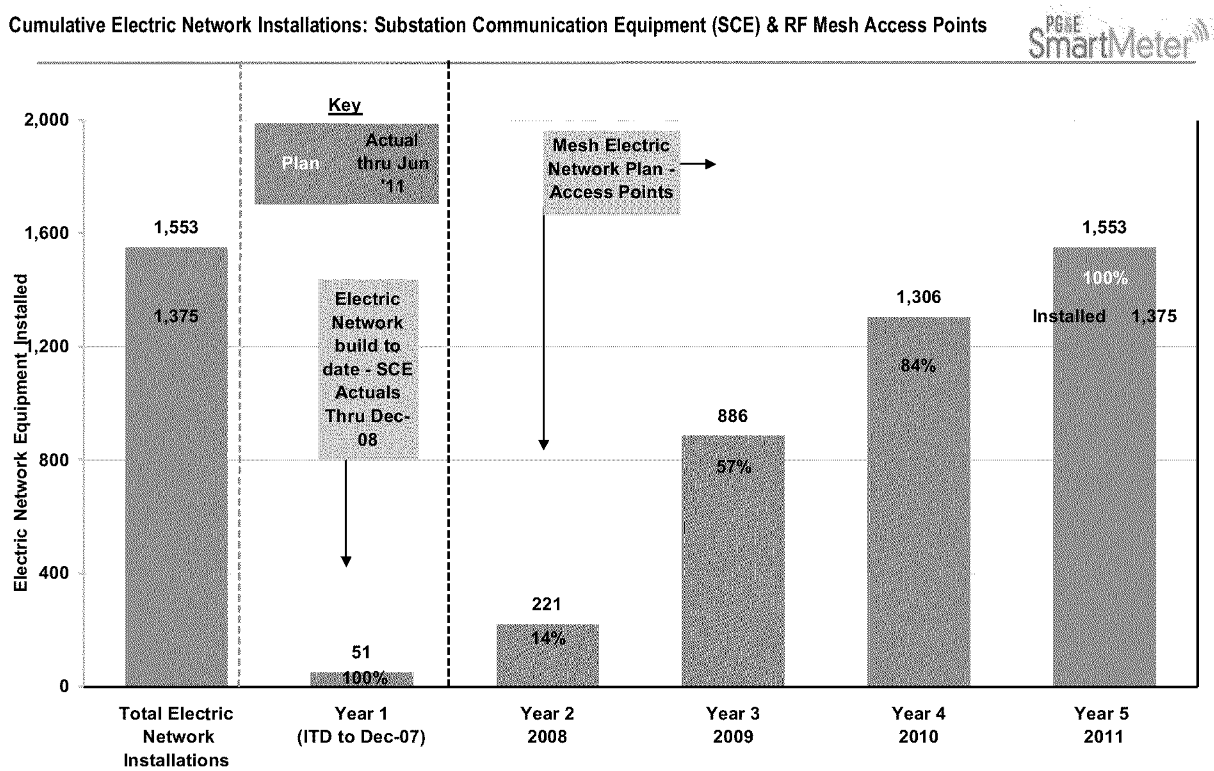
*Includes installation of retrofitted SmartMeters™.

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

PG&E continues to make progress in the deployment of gas and electric network infrastructure, the installation of gas and electric meters and communication modules, and the activation of gas and electric meters.

The following figures summarize the progress of PG&E's SmartMeter™ Program implementation in each respective area through June 30, 2011. 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.

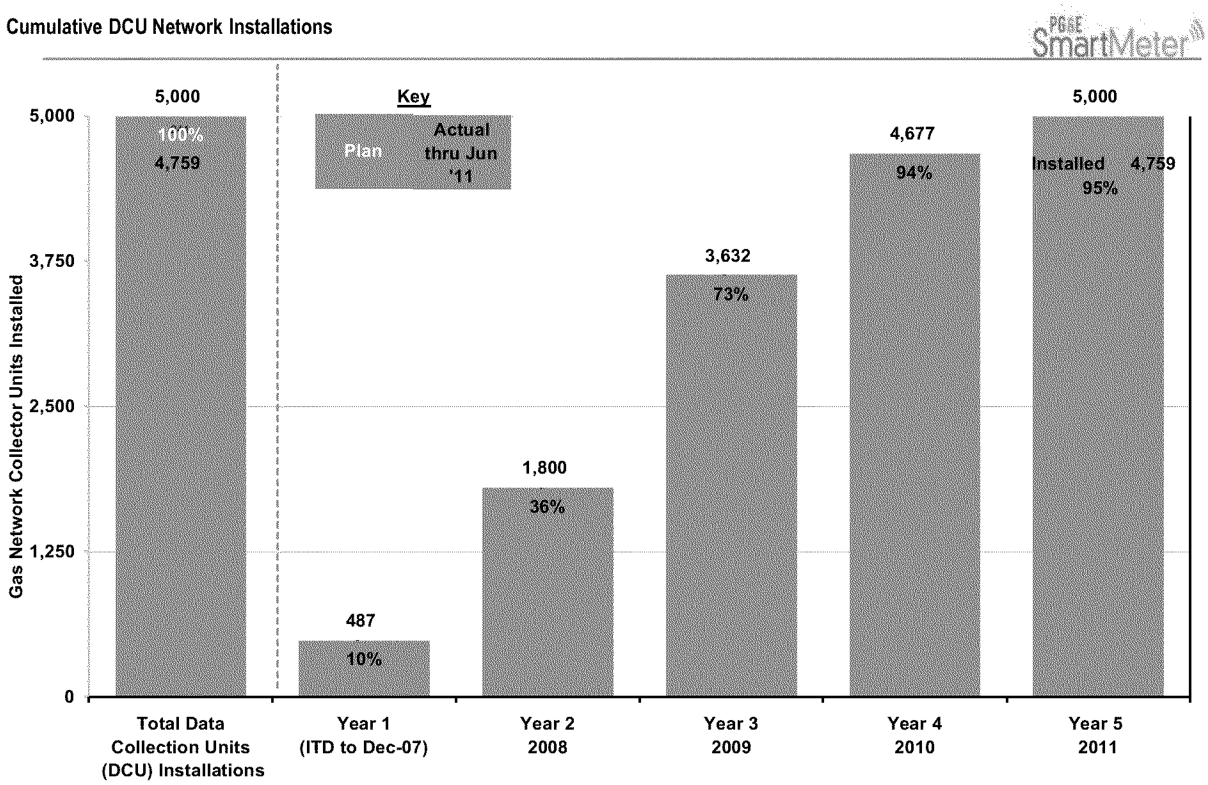
Table III – 2



Electric Network - Substation SCE	Total	Yr 1 (to Dec-07)
Cumulative Installed thru 06/11	51	51
Plan	51	51

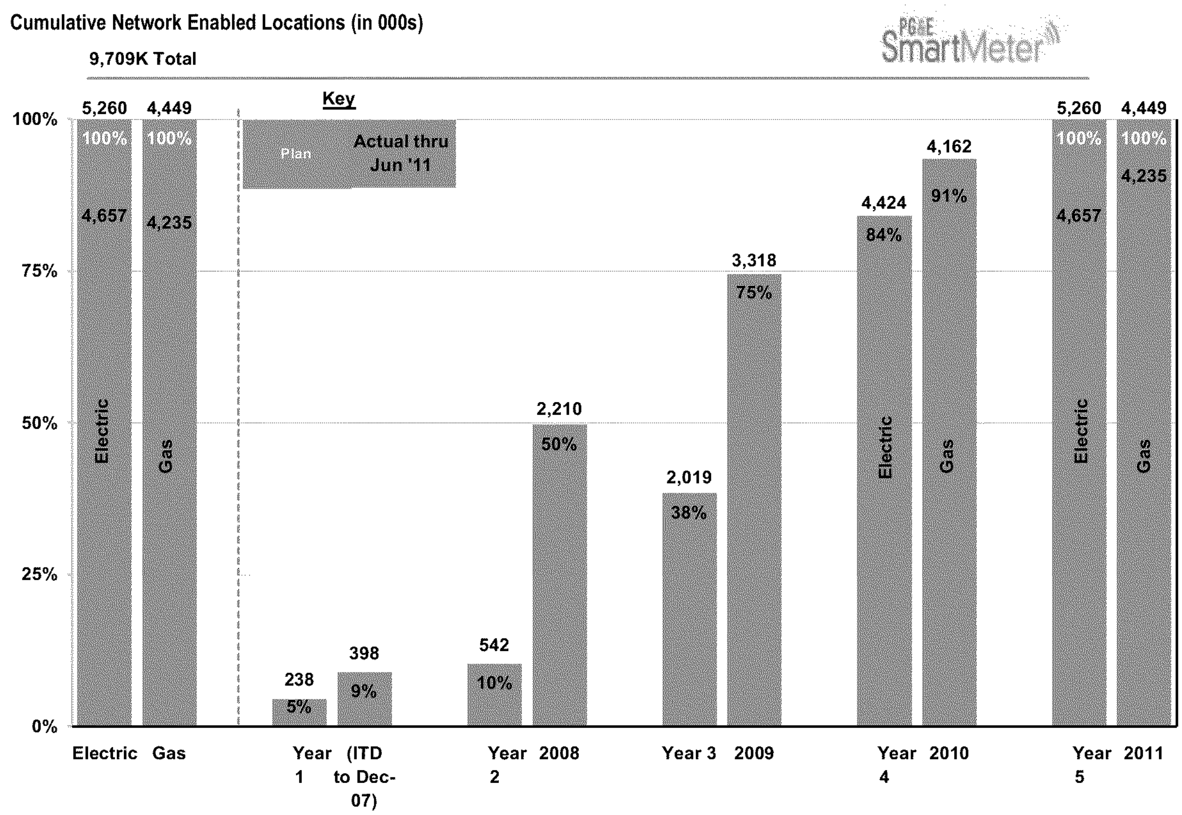
Electric Network - RF Mesh Access Points	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Cumulative Installed thru 06/11	1,375	-	221	886	1,306	1,375
Plan	1,553	-	221	886	1,306	1,553

Table III - 3



Cumulative Data Collection Unit (DCU) Installations	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Installed thru 06/11	4,759	487	1,800	3,632	4,677	4,759
Plan	5,000	487	1,800	3,632	4,553	5,000

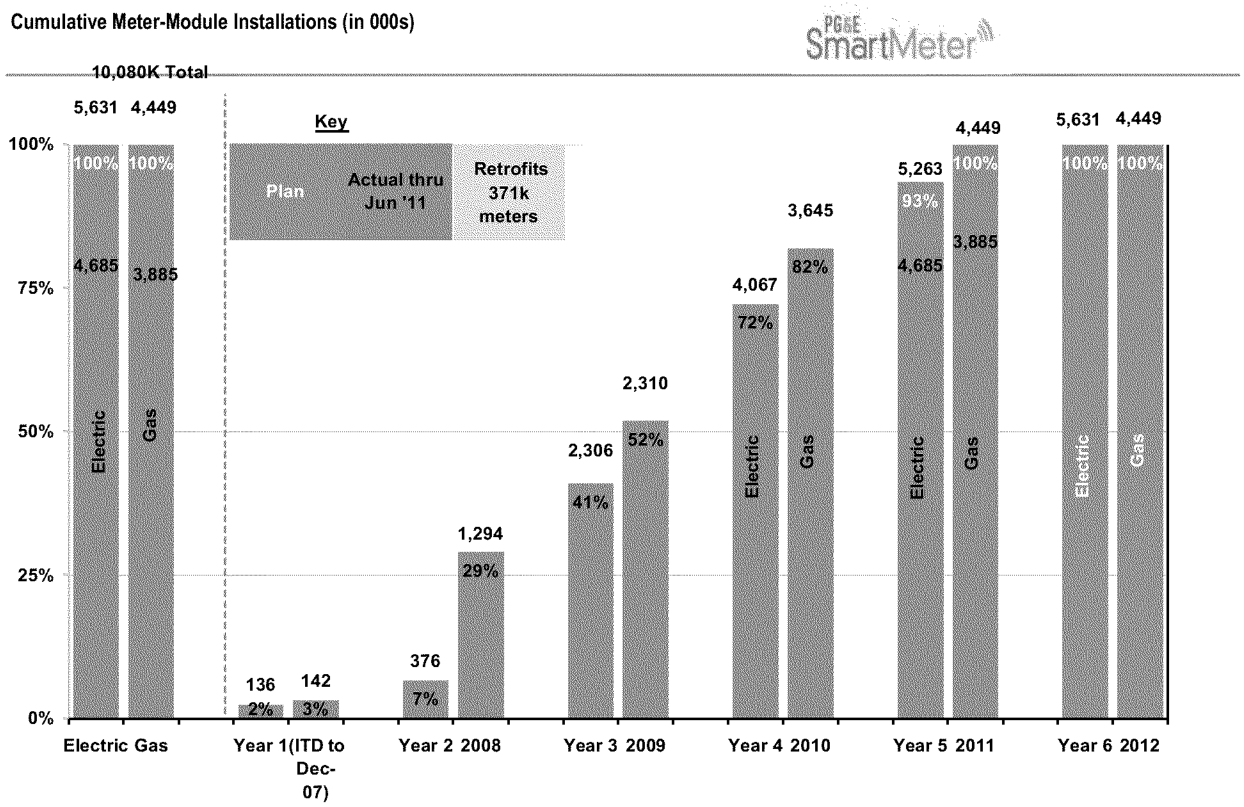
Table III - 4



Cumulative Network Enabled Locations	Total	2007		2008		2009		2010		2011	
(000)		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Enabled thru 06/11	8,892K	238K	398K	542K	2,210K	2,019K	3,318K	4,424K	4,162K	4,657K	4,235K
Plan*	9,709K	238K	398K	542K	2,210K	2,019K	3,318K	4,722K	4,029K	5,260K	4,449K

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

Table III - 5



Cumulative Meter-Module Installations	Total	Year 1		Year 2		Year 3		Year 4		Year 5		Year 6	
(000)		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Installed thru 06/11	8,570K	136K	142K	376K	1,294K	2,306K	2,310K	4,067K	3,645K	4,685K	3,885K	-	-
Plan*	10,080K	136K	142K	376K	1,294K	2,306K	2,310K	4,067K	3,645K	5,263K	4,449K	5,631K	4,449K

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

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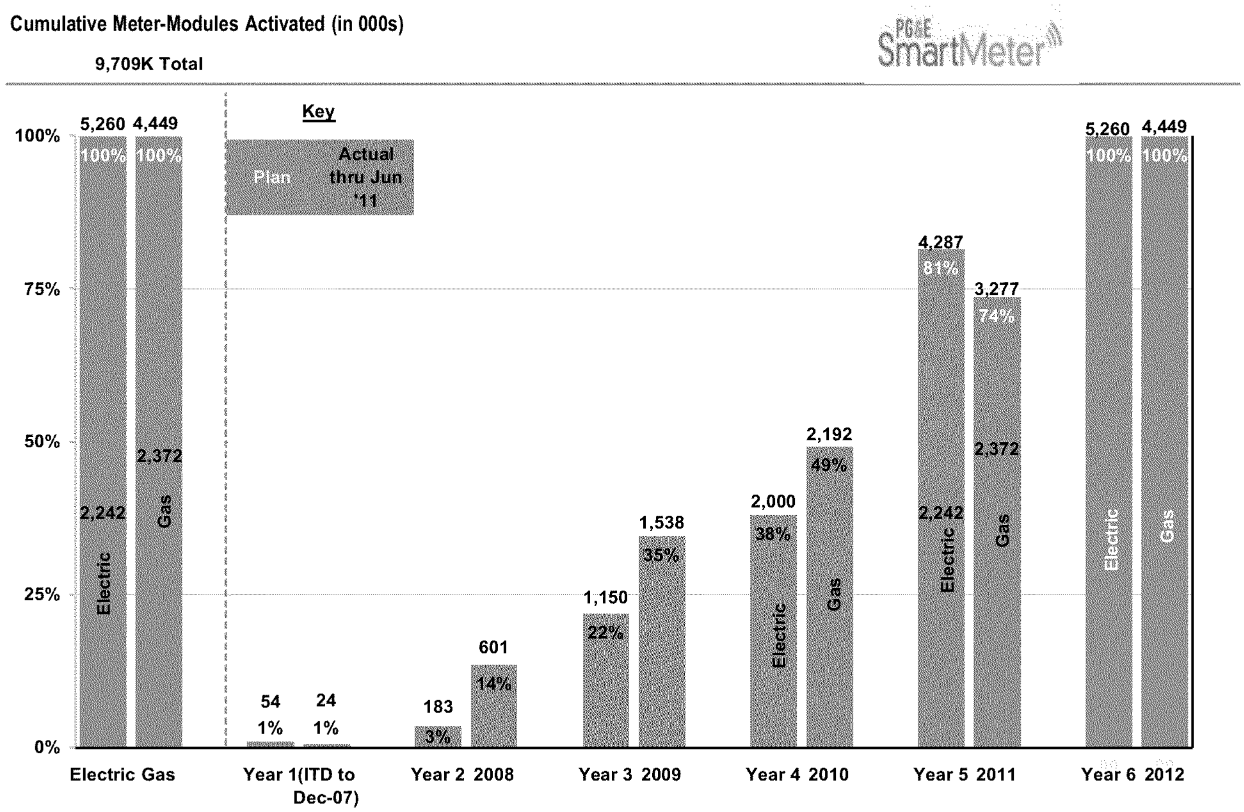
Table III - 6



Cumulative Meters Activated	Total	2007		2008		2009		2010		2011		2012	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Activated thru 06/11	4,614K	54K	24K	183K	601K	1,150K	1,538K	2,000K	2,192K	2,242K	2,372K	-	-
Plan*	9,709K	54K	24K	183K	601K	1,150K	1,538K	2,485K	2,247K	4,287K	3,277K	5,260K	4,449K

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

IV. Program Costs and Benefits

A. SmartMeter™ Program Costs

The SmartMeter™ Project Management Office (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 includes a risk-based allowance, which was authorized by the CPUC to provide for unanticipated costs necessary to complete 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, which reflect both the allocation of the $178 million risk-based allowance and the additional $129 million Board-approved costs.

Through June 30, 2011, the SmartMeter™ Program incurred costs of approximately $2,143 million ($1,745 million in capital and $398 million in expense). Of this total dollar amount, Field Delivery activities have cost approximately $1,411 million (66 percent) and IT-related activities have cost approximately $467 million (22 percent). The remaining 12 percent is attributed to the Customer & SM Operations and PMO categories. The Program's total estimated cost at completion of $2,335 million is based on the combined CPUC cost authorizations of the AMI Decision ($1,739 million) and Upgrade Decision ($467 million), as well as the additional $129 million of Board-approved costs.

Table IV - 1

($ Millions)	TOTAL	Field Delivery	Information Technology	Customer & SM Operations	PMO	Risk-Based Allowance
Plan as of December 31, 2010	2,206	1,438	493	179	96	
Cost Adjustments	129	99	-	21	10	
Plan as of June 30, 2011	2,335	1,537	493	200	106	
Risk-Based Allowance Drawdown to Date	3					3
Future Potential Use	(3)					(3)
Total Risk-Based Allowance	-					-
Additional Board-approved Cost	129					
Actuals Thru 6/30/11	2,143	1,411	467	168	97	
% of Plan	92%	92%	95%	84%	92%	

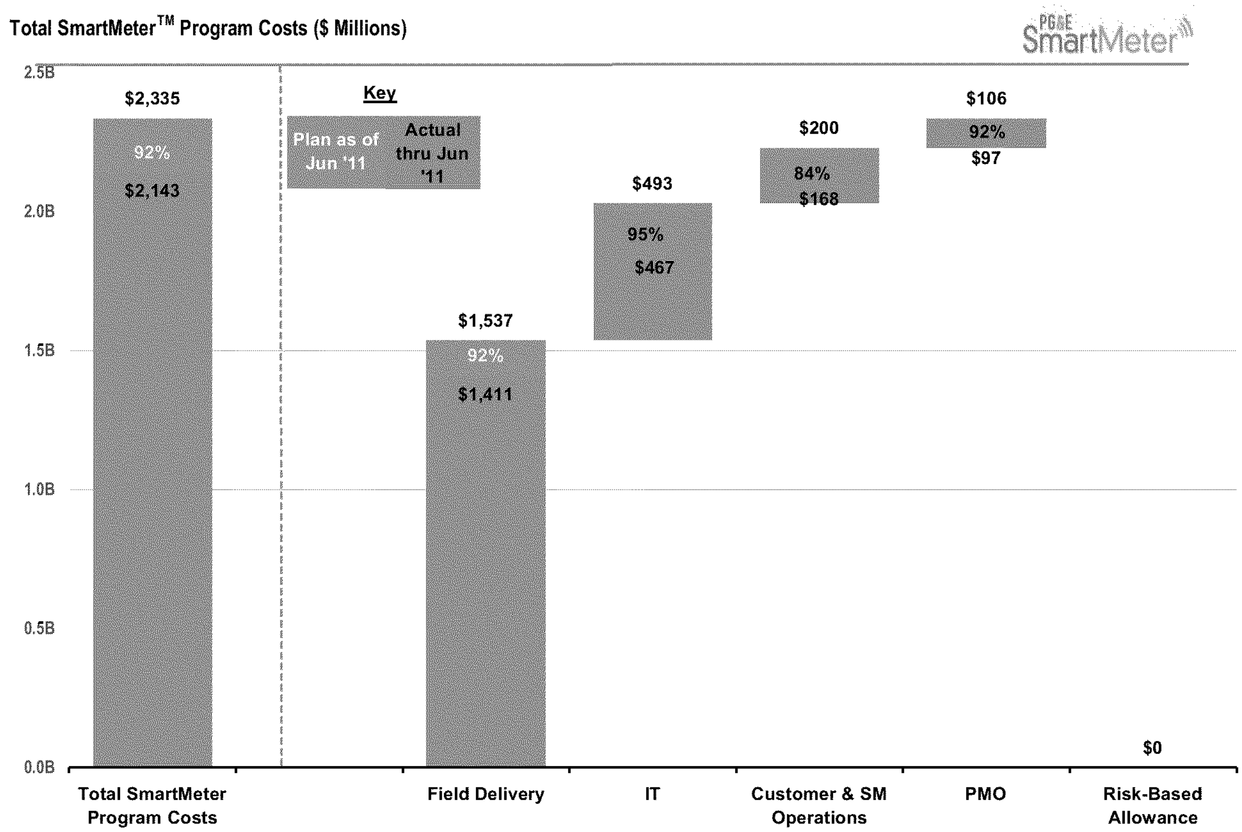
Note: Totals subject to rounding

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 June 30, 2011, approximately $28.4 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	2010 Actual	2011 Actual	Total
SmartRate™ Marketing & Education and Customer Web Presentment	0	349	1,166	6,811	6,454	2,400	11,178	28,358

Tables IV-2 through IV-7 show PG&E's incurred costs from inception through June 30, 2011, for the SmartMeter™ Program, as well as each respective budget category. The percent-of-expenditures refers to the total incurred expenditure as of June 30, 2011 as a percentage of the adjusted workstream budgets.

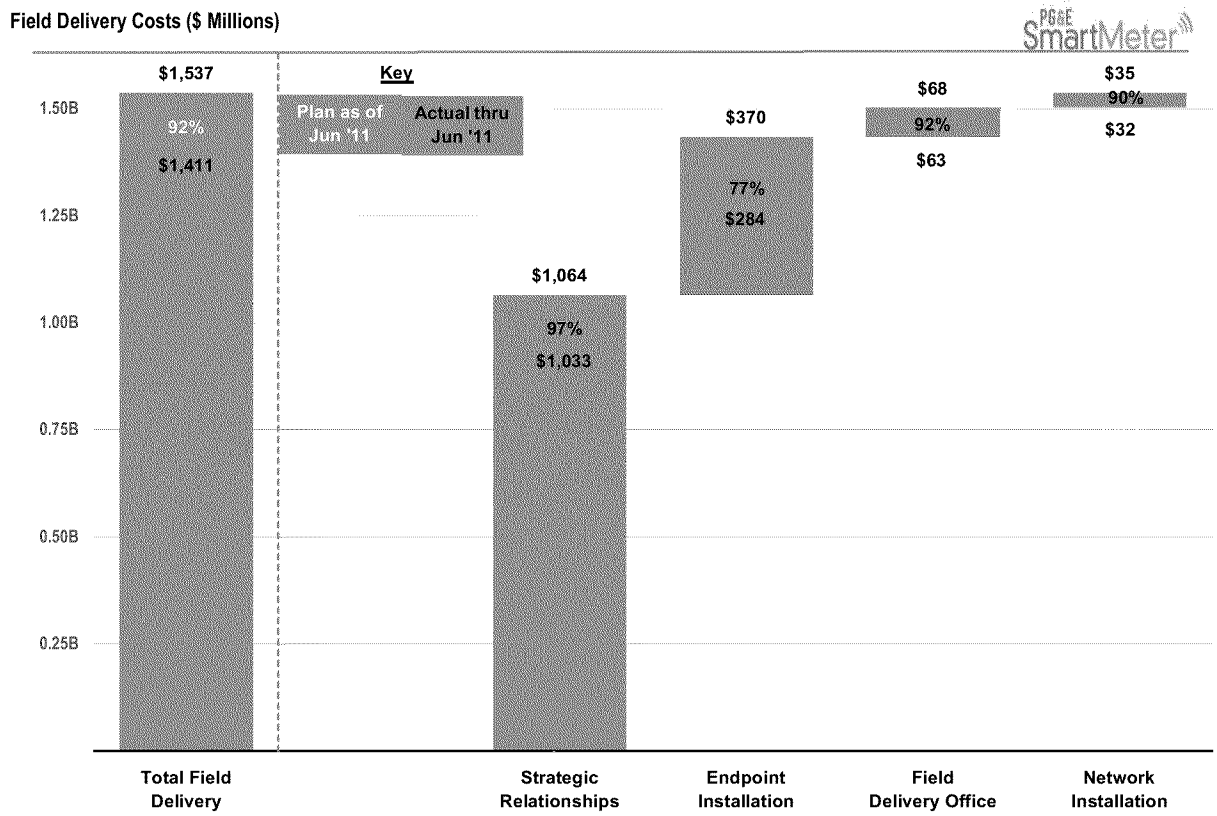
Table IV – 2



$ Millions	Total SmartMeter Program Costs	Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allowance
Actuals thru June 30, 2011	2,143	1,411	467	168	97	N/A
Plan as of December 31, 2010	2,206	1,438	493	179	96	-
Cost Changes/Reallocation	129	99	-	21	10	-
Plan as of June 30, 2011	2,335	1,537	493	200	106	-
% of Plan Expended	92%	92%	95%	84%	92%	

Note: Totals subject to rounding

Table IV – 3

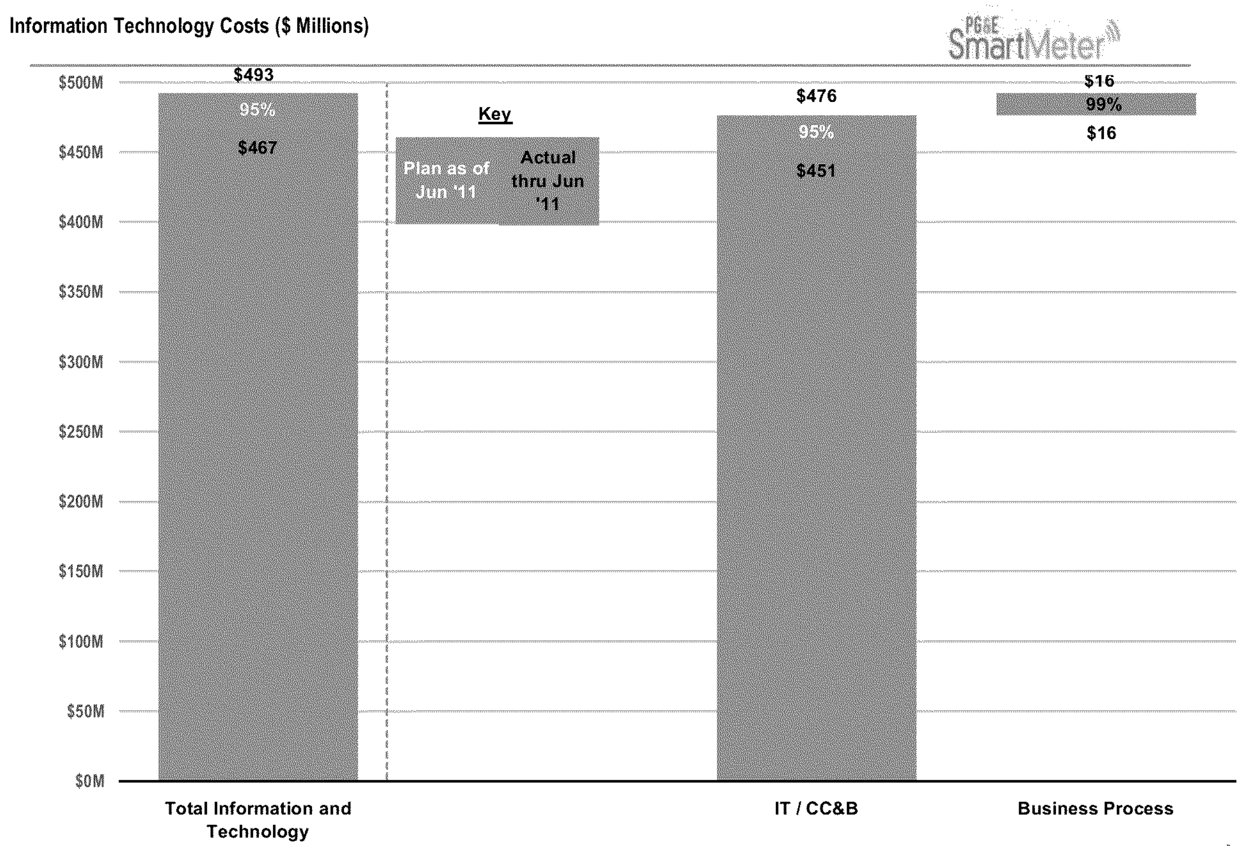


$ Millions	Total Field Delivery	Strategic Relationships	Endpoint Installation	Field Delivery Office	Network Installation
Actuals thru June 30, 2011	1,411	1,033	284	63	32
Plan as of December 31, 2010	1,438	1,140	138	131	29
Cost Changes/Reallocation	99	(76)	232	(63)	6
Plan as of June 30, 2011	1,537	1,064	370	68	35
% of Plan Expended	92%	97%	77%	92%	90%

$ Millions	Network Installation	Electric Network	Gas Network
Actuals thru June 30, 2011	32	20	11
Plan as of December 31, 2010	29	12	17
Cost Changes/Reallocation	6	12	(5)
Plan as of June 30, 2011	35	24	12
% of Plan Expended	90%	86%	97%

Note: Totals subject to rounding. Some Field Delivery (FD) costs have been realigned among the FD subcategories to reflect the Project's management of the respective activities.

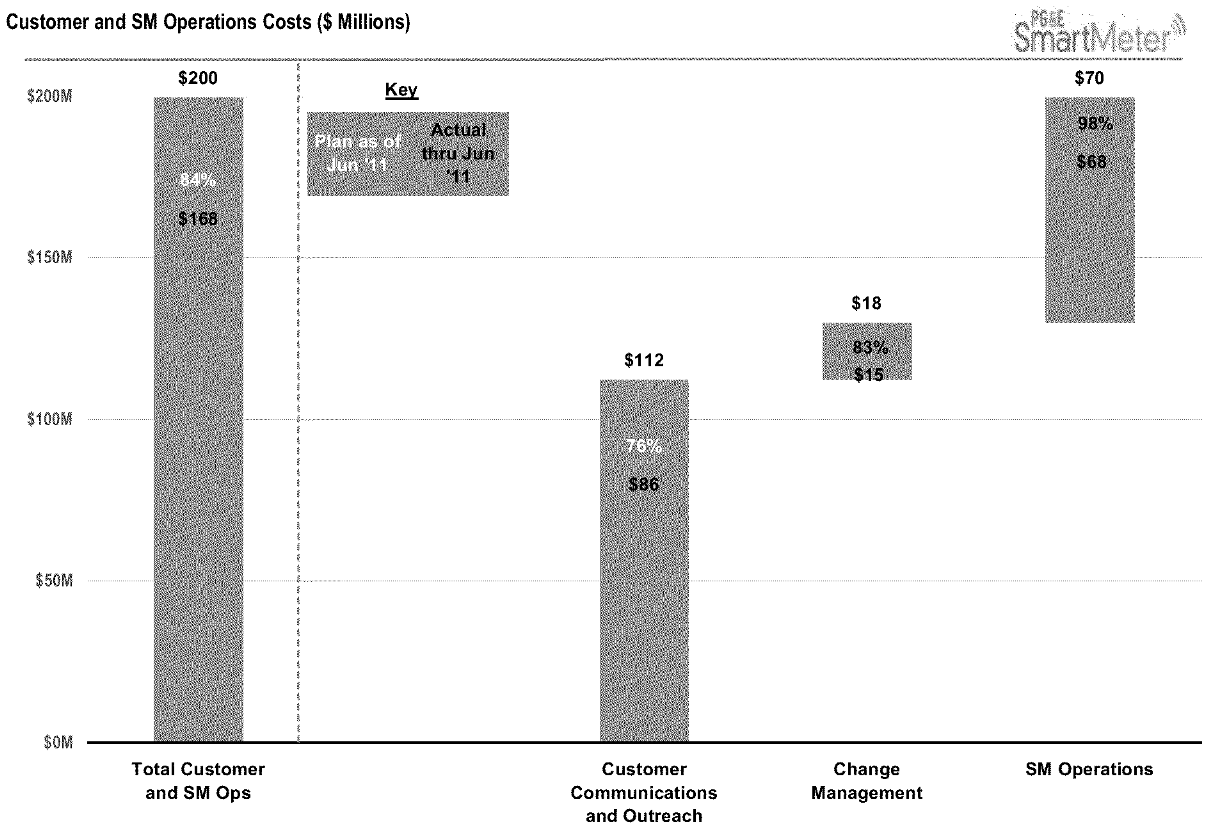
Table IV - 4



$ Millions	Total Information and Technology	IT / CC&B	Business Process
Actuals thru June 30, 2011	467	451	16
Plan as of December 31, 2010	493	478	15
Cost Changes/Reallocation	(0)	(2)	1
Plan as of June 30, 2011	493	476	16
% of Plan Expended	95%	95%	99%

Note: Totals subject to rounding

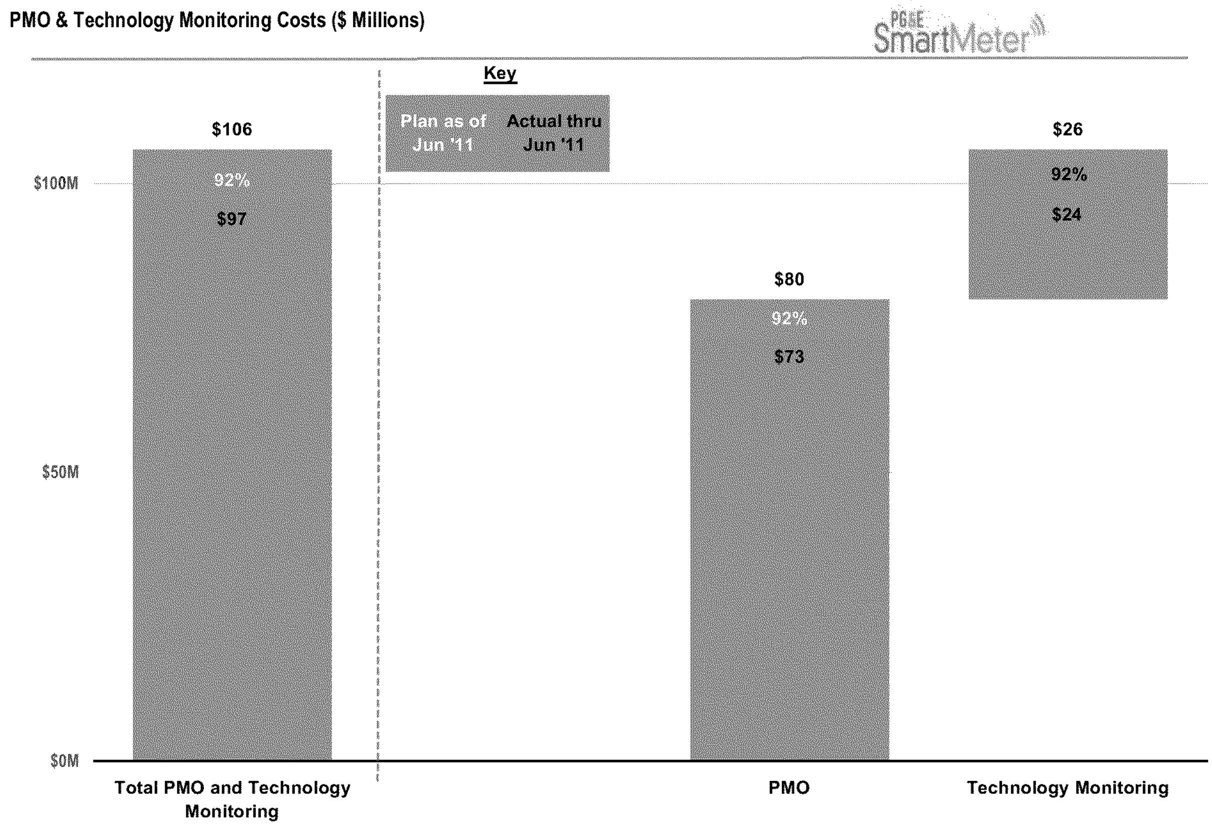
Table IV - 5



$ Millions	Total Customer and SM Ops	Customer Communications and Outreach	Change Management	SM Operations
Actuals thru June 30, 2011	168	86	15	68
Plan as of December 31, 2010	179	98	13	68
Cost Changes/Reallocation	21	14	5	2
Plan as of June 30, 2011	200	112	18	70
% of Plan Expended	84%	76%	83%	98%

Note: Totals subject to rounding

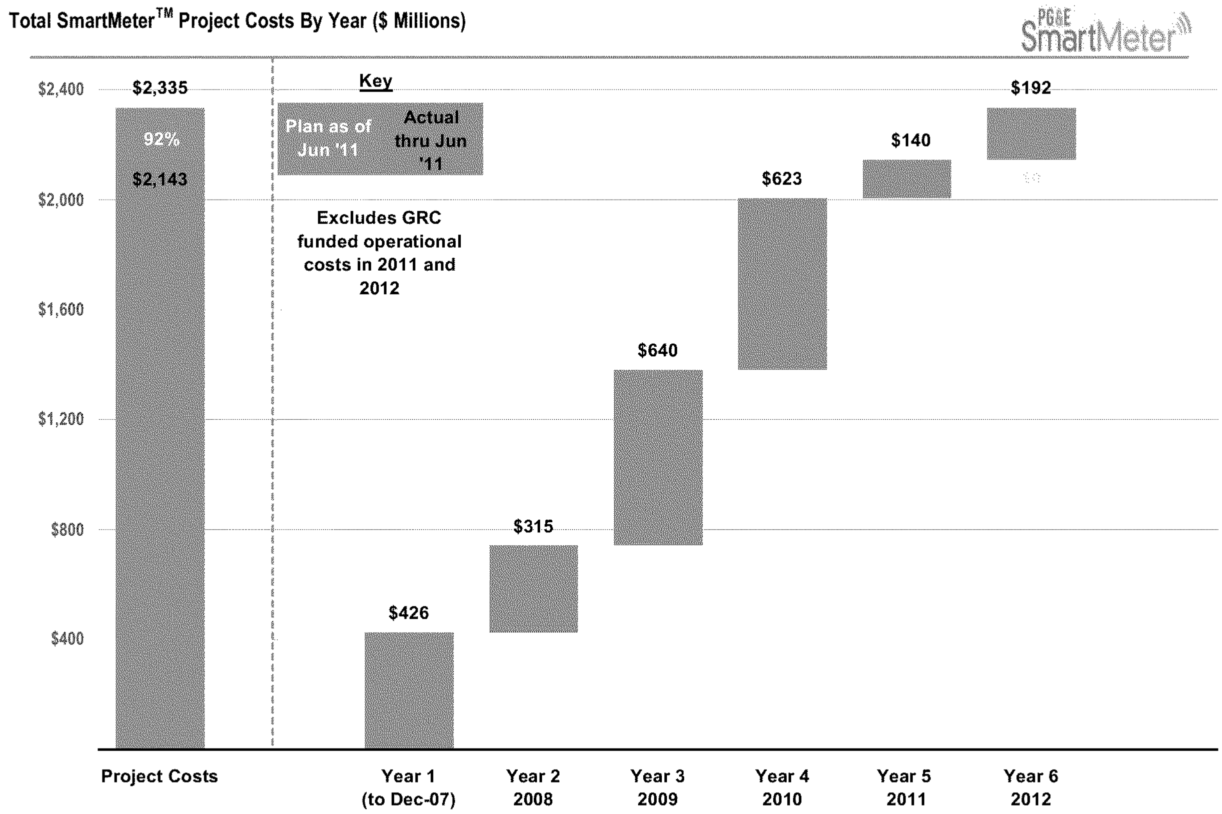
Table IV - 6



$ Millions	Total PMO and Technology Monitoring	PMO	Technology Monitoring
Actuals thru June 30, 2011	97	73	24
Plan as of December 31, 2010	96	70	26
Cost Changes/Reallocation	10	10	(0)
Plan as of June 30, 2011	106	80	26
% of Plan Expended	92%	92%	92%

Note: Totals subject to rounding

Table IV – 7



$ Millions	Project Costs	Year 1 (to Dec-07)	Year 2 (CY 2008)	Year 3 (CY 2009)	Year 4 (CY 2010)	Year 5 (CY 2011)	Year 6 (CY 2012)
Actuals thru June 30, 2011	2,143	426	315	640	623	140	-
Plan as of June 30, 2011	2,335						192

Note: Totals subject to rounding. Project costs have been adjusted to reflect the inclusion of cost of removal amounts previously considered recover able outside of the SmartMeter™ balancing accounts.

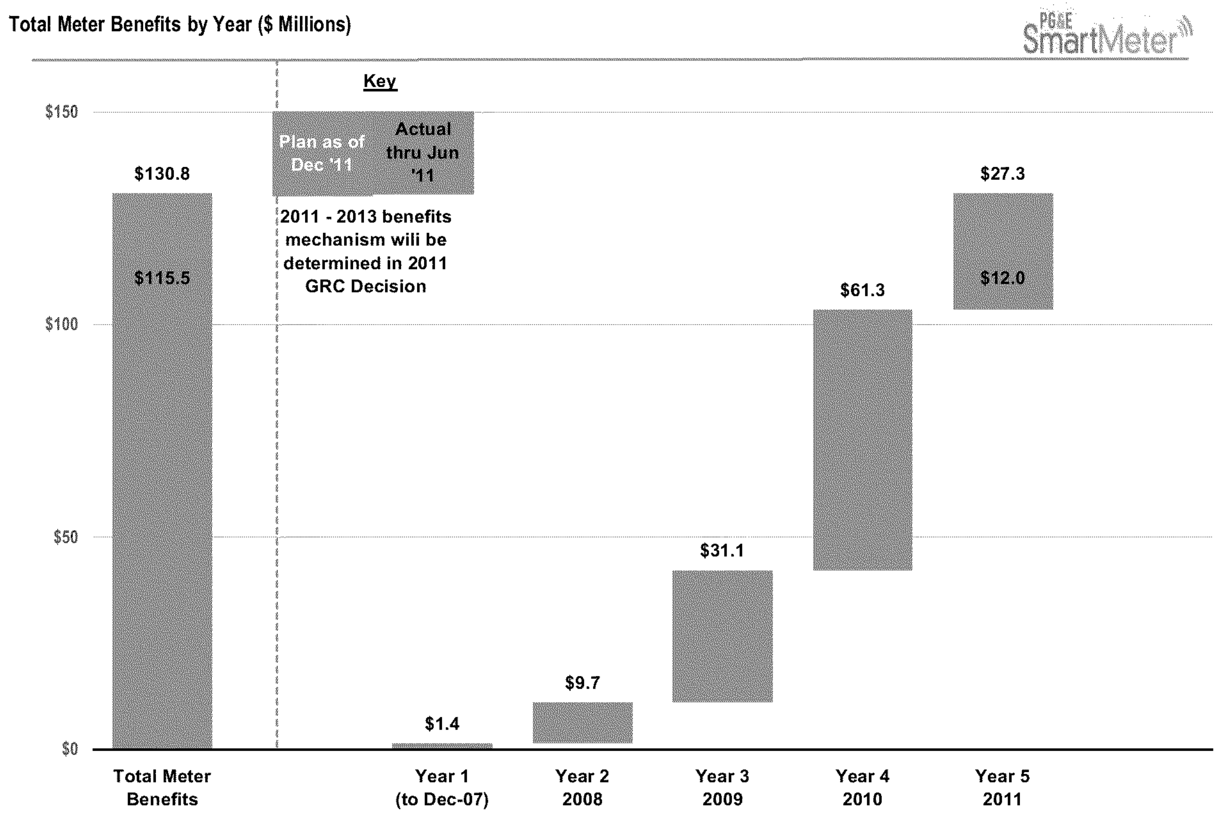
B. Operational Benefits Realization

The Program realizes benefits primarily when meters fitted with SmartMeter™ technology are installed, transitioned, and activated. After installation, gas and electric meters transition when: (1) the communications network infrastructure is in place to remotely read the meters; (2) the meters are installed, remotely read, and utilize SmartMeter™ data for billing; and (3) the remote meter reads become stable and reliable for billing purposes. Once enough customers on a particular “route string” transition to SmartMeter™ billing, manual reading of the meters on that “route string” ceases and those meters are considered activated.

As reported in the January 2008 Report, the first meter activations occurred in December 2007. Since then, approximately 7,409,000 meters have been transitioned, and approximately 4,614,000 meters have been activated (as of June 30, 2011). Total cumulative benefits recorded as credits to the balancing accounts as of June 30, 2011 are $115.5 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 AMI and Upgrade Decisions, as well as the 2011 GRC Decision.

Table IV-8 shows activated meters and the corresponding benefits based on the average savings rates adopted in the AMI and Upgrade Decisions. These benefits included $1.9543 per meter per month for electric and $1.0366 per meter per month for gas until the 2011 GRC Settlement was adopted. In compliance with the GRC Settlement, the activated meter benefits were adjusted retroactively to January 1, 2011 to reflect agreed-upon changes, the largest being the removal of meter reading savings that are now reflected in a new Meter Reading Balancing Account (MRBA). The activated meter benefits in effect since January 1, 2011, based on the 2011 GRC Settlement, are $0.9225 per meter per month for electric and $0.0189 per meter per month for gas.

Table IV – 8



Activated Meter Benefit - Actuals (As of June 30, 2011)		Year 1	Year 2	Year 3	Year 4	Year 5
(in thousands)		(ITD Dec-07)	(CY 2008)	(CY 2009)	(CY 2010)	(CY 2011)
Meters						
Activated Electric meter months		50	1,436	6,669	17,495	12,749
Activated Gas meter months		21	2,086	12,666	21,341	13,709
Total Activated meter months		71	3,521	19,335	38,836	26,458
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	$34,191	-
Gas at $1.04 per meter month	$1.04	$22	$2,162	$13,129	$22,122	-
Electric at $0.92 per meter month		-	-	-	-	$11,761
Gas at $0.02 per meter month		-	-	-	-	$259
Reduced Software Licensing		$1,251	$5,000	$5,000	$5,000	-
Automate Interval Billing		-	-	-	-	-
		$1,362	$9,706	$31,054	$61,313	$12,020

Note: Totals subject to rounding. Year 4 column has been corrected from the March 31, 2011 Semi-Annual Report.

V. System Performance Criteria Metrics

System performance criteria and metrics are measured and reported on an on-going basis as meter installations progress. As stated in previous reports, 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.

In Table V-1, PG&E has summarized SmartMeter™ Program Data metrics for timely and estimated bills for the second quarter of 2011.

Table V - 1

Timely Bills[1]		
Month	Overall	SmartMeter
April '11	99.71%	99.79%
May '11	99.77%	99.87%
June '11	99.80%	99.91%

[1]Total % of Service Agreements (SAs) Billed ≤ 35 Days as compared to all active SA's.

Estimated Bills[1]		
Month	Overall	SmartMeter
April '11	0.46%	0.07%
May '11	0.41%	0.08%
June '11	0.41%	0.07%

[1]Number of bill segment calculations based on estimated usage as a % of all completed bill segments.

The performance criteria presented in Table V-2 are based on the number of actual reads retrieved by the head-end system versus the expected number of reads provided by the system. Deployment in areas with poor communications coverage degrades performance, while firmware upgrades and supplemental network designs for existing and new installations improve performance. 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 – 2

Performance Criteria	Jan'11 thru Jun'11	Jul'10 thru Dec'10	Jan'10 thru Jun'10	Jun'09 thru Dec'09	Jan'09 thru Jun'09	Jul'08 thru Dec'08
1. Electric module failure rate	0.42%	0.45%	0.09%	0.34%	0.12%	0.05%
2. Gas module failure rate	0.27%	0.09%	0.14%	0.36%	0.45%	0.05%
3. Electric network failure rate	0.52%	0.35%	0.23%	0.63%	0.29%	0.35%
4. Gas network failure rate	0.65%	0.13%	0.14%	0.34%	0.24%	0.20%
5. Electric billing data collection failure rate	0.23%	0.27%	0.39%	1.14%	0.81%	0.75%
6. Gas billing data collection failure rate	0.29%	0.23%	0.16%	0.22%	0.20%	0.13%

The definitions of the system performance criteria presented in Table V-2 follow:

Electric module failure rate: This rate represents the incidence of meters removed specifically for suspected meter hardware failures (such as blank displays, meter/module hardware errors, and non-communicating meters). This rate does not count external causes (like broken covers, customer-damaged meters, or tampering/theft). Meters removed for suspected meter hardware failures are investigated through the Return Material Authorization (RMA) process.

Gas module failure rate: This rate represents the incidence of modules removed specifically for suspected hardware failures (such as bad battery/poor charging patterns, bad module circuits, and non-communicating modules). This rate does not count external causes (like customer-damaged meters, scheduled meter changes, or dog-caused damage). Modules removed for suspected hardware failures are investigated through the RMA process.

Electric network failure rate: This rate represents the incidence of network components removed and submitted for RMA (such as APs and relays failing to communicate or failing to maintain charging capacity). This rate also includes component failure in substation communication equipment.

Gas network failure rate: This rate represents the incidence of gas network components removed and submitted for RMA (such as components failing to maintain charging capacity, drifting off frequency, experiencing cellular failures, and experiencing failed electronic boxes).

Electric billing data collection failure rate: This rate represents the number of electric SmartMeters™ from which complete data (complete backhaul data, daily anchor, and complete set of intervals) were not retrieved, divided by the total number of electric SmartMeters™. This measure consists of the percentage of complete daily data sets, one good anchor read and complete good interval reads, averaged over the defined period. Any service point with an estimated anchor and/or estimated interval read(s) fails this measure and is excluded. Failure of this read metric does not lead to an estimated bill; an accurate bill can be generated in most cases.

Gas billing data collection failure rate: This rate represents the number of gas SmartMeters™ from which a daily cumulative read was not retrieved, divided by the total number of gas SmartMeter™ devices. Failure of this read metric does not lead to an estimated bill; an accurate bill can be generated in most cases.

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

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™ events are triggered when temperatures surpass a preset threshold. As of June 30, 2011, the SmartRate™ Program had 22,930 active residential customers.

Decision 10-02-032, which adopted Peak Day Pricing (PDP) rates, ordered 172 small to medium business customers then on SmartRate™ to transition to PDP rates on

May 1, 2010. The transition of the non-residential customers from SmartRate™ to PDP started in May 2010. The decision also ordered residential customers on SmartRate™ to default to PDP on February 1, 2011. PG&E requested, and was granted, an extension to November 1, 2011 for residential customer transition. As a result, the residential SmartRate™ Program was extended until October 31, 2011. On January 14, 2011, PG&E filed a Petition for Modification of Decision10-02-032, asking the Commission to delay the default of residential SmartRate™ participants to PDP and to retain SmartRate™ as an option for residential customers until residential dynamic pricing options are considered again by the Commission. The Executive Director granted PG&E's request on May 5, 2011, but established a default date of November 1, 2012, pending the Commission's decision on PG&E's Petition for Modification.

In April 2011, PG&E filed its 2010 Load Impact Evaluation report for Residential SmartRate™ PDP and Time-of-Use Tariffs and the SmartAC™ Program, which included information on the 2010 season performance of the SmartRate™ population. The results included:

- There were 13 SmartDays™ during the 2010 season (May 1 through October 31).
- On average, participants reduced peak electricity use by 16.9 percent across the 13 event days.
- August 2010 offered the season's highest average reduction – 17.4 percent – in peak electric use.
- In general, participants with central air conditioning reduced peak electricity use more than those without it.

- Across all geographic planning regions, low-income customers' peak electricity consumption was similar to that of standard tariff customers during non-event days.

During the first half of 2011, PG&E called two SmartDays™. Temperatures during summer 2011 have been, once again, unseasonably cooler than average and the trigger temperature has been decreased to 92 degrees.

The following are highlights from the 2010 year-end customer satisfaction study for SmartRate™:

- 81 percent of 2010 customers report being very satisfied with SmartRate™.
- A higher share of low-income respondents – 91 percent – reported being very satisfied with SmartRate™.
- 79 percent of respondents perceived they were saving energy during their SmartRate™ participation and more than 90 percent actually experienced lower costs.
- 95 percent of 2010 SmartRate™ customers planned to continue on SmartRate™ in 2011.
- 88 percent of SmartRate™ customers would recommend SmartRate™ to a friend.

In 2010, PG&E made changes to its SmartRate™ marketing strategy to account for the program's ending in 2010 and the CPUC's decision to default all SmartRate™ customers to PDP rates in February 2011. In response to the Commission's extension of the SmartRate™ Program into the 2012 demand response season, PG&E has continued this customer outreach approach in 2011, seeking to support the current population of participants.

Given that many SmartRate™ customers have now been on the program for several years, the 2011 outreach to existing customers focuses on keeping customers engaged in the program. PG&E sent a series of postcards and emails to existing SmartRate™ customers that featured testimonials describing the simple actions customers may take on SmartDays™ to save energy and money. PG&E encouraged customers to visit PGE.com to learn more about what other customers are doing to be successful on SmartRate™ as well as to submit their own SmartDay™ energy saving tips.

VII. SmartMeter™ Information Technology Progress

In the first half of 2011, PG&E introduced significant changes to the organizational and project-based structure of the IT components of PG&E's SmartMeter™ Program. The scope and funding for nine individual projects and performance improvement efforts originally in the SmartMeter™ Program were consolidated into a single project called the SmartMeter™ Technology Completion Project (SMTCP). Currently, the SMTCP consists of three releases that encompass all of the remaining SmartMeter™ IT scope and will be completed by year-end 2011 within the currently-allocated project budget. Two IT projects (related to HAN and the Peak Time Rebate program) were deferred, along with their budgeted dollars, until the CPUC determines the scope and timeline for the programs.[5]

The functionality being delivered in each of the three releases are:

- Release 1: July 2011
    - Remote Connect/Disconnect
    - Model Office, Part 1

[5] As noted in Section II of this Report, in Decision 11-07-056, the Commission ordered PG&E and the other California electric utilities to file HAN "rollout" implementation plans by the end of November 2011. In the August 18, 2011 Assigned Commissioner Peevey Ruling in the Peak Time Rebate proceeding (A.10-02-028), PG&E was directed to file updated testimony on October 28, 2011. PG&E does not expect Commission decisions on these two matters until 2012.

    - Secure Port/Secure Field Service Unit
    - Performance and Scalability upgrades
    - Carry-over Customer Care and Billing System service requests
- Release 2: September 2011
    - Outage Management – Identify and Scope Outages
- Release 3: November 2011
    - Outage Management – Probability Fault and Metrics
    - Net Energy Metering Management
    - Exception Management
    - Customer Care Operations
    - Enhanced Outage Notification
    - Model Office, Part 2
    - Measure Bill Collect Data Warehouse Advanced Compression

VIII. SmartMeter™ Transition to Operations

Beginning in 2011, recurring SmartMeter™ activities that will continue after the Program are transitioning to traditional operations organizations. In support of this effort, PG&E has initiated significant employee outreach and change management activities to address employee education conducted by the SmartMeter™ Change Management team. In addition, a cross-functional team of project and business experts has also been working to seamlessly move the SmartMeter™ network from a project mode towards full integration with PG&E's normal business.

Business departments that are directly affected by this transition and currently receiving training include: Contact Center Operations, Office Services, Meter to Cash, Service Planning, Gas and Electric Meter Shop, Restoration, Customer Field Services, Energy Service and Solutions, Telecommunications, and Gas and Electric Maintenance and Construction. Transition planning has begun with business departments, with transitions beginning as early as March 2011 and continuing through the end of deployment. In parallel with these activities, Employee Change Management is partnering with Information Technology, Governmental Relations, and Internal and External Communication departments to ensure employees are well-prepared ahead of implementation.

IX. Other Program Updates

On March 24, 2011, PG&E submitted Application 11-03-014 to the CPUC proposing to modify the SmartMeter™ program to enable residential customers to have PG&E turn off the radios in their gas and/or electric SmartMeters™. The proposed program is estimated to cost $113.4 million ($38.3 million in capital and $75.1 million in expense) through 2013, based on market research projections of 2.7 percent of residential customers exercising this choice (145,800 customers). The costs would be subject to balancing-account treatment and true-up, with a future forecast based on actual experience to be presented in PG&E's 2014 GRC. Customers who choose to participate in this program will bear all of its costs, with California Alternative Rates for Energy (CARE) customers receiving a 20 percent discount. Customers who keep their SmartMeter™ radios turned on will pay no additional fees.

On April 5, 2011, the California Council on Science and Technology (CCST) issued its final report regarding whether the RF signals from SmartMeters™ pose any health risk. The CCST report reached the conclusion that SmartMeters™ comply with every known health standard and that there is no evidence that additional standards are needed to protect the public from SmartMeter™-related RF.

On May 2, 2011, PG&E announced that it would replace a small number of the electric SmartMeters™ supplied by L+G due to a rare defect in the meters. L+G determined the error affected approximately 1,600 of the two million meters it supplied to PG&E. PG&E replaced the meters at no cost to customers and issued full refunds to customers who received inaccurate bills. The average refund was about $40 per customer. PG&E also issued a $25 credit for customer inconvenience and offered a free in-home energy audit to affected customers. As of June 30, 2011, PG&E had replaced a total of 1,572 L+G meters affected by the defect.