
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

1 **Pacific Gas and Electric Company**
2 **Advanced Metering Infrastructure Semi-Annual Assessment Report**
3 **SmartMeter™ Program Quarterly Report**
4 **September 2011**

5 **I. Executive Summary**

6 A. Introduction

7 This is Pacific Gas and Electric Company's (PG&E or the Company) tenth semi-
8 annual assessment report (Report) regarding the deployment of PG&E's Advanced
9 Metering Infrastructure (AMI) Program (now the SmartMeter™¹ Program) and serves as
10 the ninth quarterly report for the SmartMeter™ Program Upgrade.

11 In Decision 06-07-027 (the AMI Decision), the California Public Utilities Commission
12 (CPUC or Commission) approved the SmartMeter™ Program that PG&E proposed in
13 Application 05-06-028. In Decision 09-03-026 (the Upgrade Decision), the CPUC
14 approved, with certain modifications, PG&E's Application 07-12-009 (the Upgrade
15 Application) to recover incremental costs associated with the SmartMeter™ Program.

16 Ordering Paragraph 16 of the AMI Decision requires that PG&E provide a semi-
17 annual report assessing AMI deployment. Ordering Paragraph 7 of the Upgrade
18 Decision requires that PG&E provide quarterly reports on the implementation progress
19 of the SmartMeter™ Upgrade. After consultation with the Commission's Energy
20 Division, PG&E has prepared this Report to comply with the requirements of both
21 Ordering Paragraph 16 of the AMI Decision and Ordering Paragraph 7 of the Upgrade
22 Decision.

23 The AMI Decision explains that the semi-annual report is intended to update the
24 Commission in the following areas: advances in AMI technology; a self-assessment of

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

1 AMI system operating performance based on performance criteria established in
2 consultation with the Energy Division and DRA; updated cost-effectiveness review; and
3 the ability to provide real-time usage data and customer interest in such data.² PG&E
4 conferred with representatives of the Energy Division and DRA to discuss the scope of
5 topics to be addressed and the metrics by which AMI is to be assessed and
6 incorporated staff comments and suggestions into this Report.

7 B. Update on the SmartMeter™ Program

8 PG&E's SmartMeter™ Program continues to progress through its objectives,
9 including deployment of endpoint devices and associated network equipment, as well as
10 implementing new information technology (IT) functionality. This section of the Report
11 provides an overview of Program developments and PG&E's progress on individual
12 elements of the Program during the first six months of 2011.

13 1. Advances in AMI Technology

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

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

² D.06-07-027 at pp. 57-58.

1 2. Progress in PG&E's AMI Deployment

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

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

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

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

7 3. Program Costs and Benefits

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

17 As of June 30, 2011, PG&E had allocated all of the \$2,355 million Board-authorized
18 project amount to Program workstreams, and continued to monitor the actual spending
19 against the forecast, as well as issues and risks that could contribute to cost overruns.
20 SmartMeter™ Program expenditures through June 30, 2011 totaled approximately
21 \$2,143 million (92 percent) of the \$2,355 million.

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

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

8 4. System Performance Criteria

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

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

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

19 6. SmartMeter™ Information Technology Progress

20 During the first half of 2011, PG&E continued the detailed testing and
21 implementation associated with the development of complex IT systems and interfaces
22 required to support the SmartMeter™ Program. Highlights of PG&E's continuing IT
23 development over the past six months are provided in Section VII of this Report.

1 7. SmartMeter™ Transition to Operations

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

8 8. Other Program Updates

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

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

1 **II. Advances in AMI Technology**

2 A. Introduction

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

9 B. PG&E Distribution Automation Update

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

15 C. PG&E's HAN Update

16 Development of PG&E's HAN enablement road map is in progress. In Decision 11-
17 07-056, the Commission ordered PG&E and the other California electric utilities to file
18 HAN "rollout" implementation plans by the end of November 2011, including an initial
19 phase rollout of up to 5,000 HAN devices by March 1, 2012. PG&E's HAN
20 Implementation Plan will describe the capabilities and schedule for PG&E's HAN-
21 enabled programs, including discussion of how standards development and market
22 adoption will affect the plan.

23 In the SmartMeter™ Upgrade Decision, PG&E was granted \$6.0 million in laboratory
24 and product demonstration costs, with the condition that PG&E can only use those

1 ratepayer-provided funds to the extent that it matches them with funds from other
2 sources³. PG&E has identified approximately \$627,000 in matching funds (within
3 technology assessment areas) and is actively working to secure the remainder of the
4 matching funds.

5 D. Technology Industry Updates

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

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

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

- 16 • UCA⁴ Open Smart Grid Technical Committee (Chair) – Providing oversight over
17 UCA's systems, communications, security, simulations, and certification and
18 testing working groups. The UCA Open Smart Grid committee (a utility
19 leadership committee) has been integral in setting utility requirements in UCA
20 and providing them to the appropriate standards bodies.

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.

- 1 • UCA Open Auto DR (Chair) – Transforming the Lawrence Berkeley National
2 Laboratory Automated Demand Response requirements from a specification to a
3 standard.
- 4 • Institute of Electrical and Electronics Engineers (IEEE) 802.15.4 Tg (Chair) –
5 Producing IEEE 802 standards for Smart Utility Networks.
- 6 • UCA OpenHAN – Setting technology independent requirements for technology
7 alliances.
- 8 • UCA Utili ENT – Setting standards for the AMI Enterprise.
- 9 • UCA Utili SEC – Establishing open security standards for the Smart Grid.
- 10 • UCA Open ADE – Defining a common interface for exchange of information
11 between utilities and third parties for customer data.
- 12 • SAE J2836 – Setting the communication standards between vehicle and grid for
13 purposes of energy transfer.
- 14 • NIST SmartGrid Architecture Committee – Creating and refining a conceptual
15 reference model, including lists of the standards and profiles, necessary to
16 implement the vision of the Smart Grid.

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

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

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

3 **III. Progress in PG&E's AMI Deployment**

4 A. Overview

5 PG&E continues to manage its meter and network deployment activities in parallel
6 with the development and implementation of the IT systems and interfaces necessary to
7 support SmartMeter™ functionality. The deployment schedule is dependent upon the
8 availability of a trained workforce, an effective supply chain to maintain an efficient
9 installation process, and access to customer premises to make the necessary changes
10 at each service location. Deployment planning adjustments may be required due to
11 several factors – including customer considerations, supply chain constraints, labor
12 availability, and technology considerations – which could affect the scheduling of meter
13 endpoint installations.

14 B. Infrastructure Installations

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

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 occurring in 2011 and 2012 is funded in the 2011 GRC and not included in the above table or the following graphs.

2

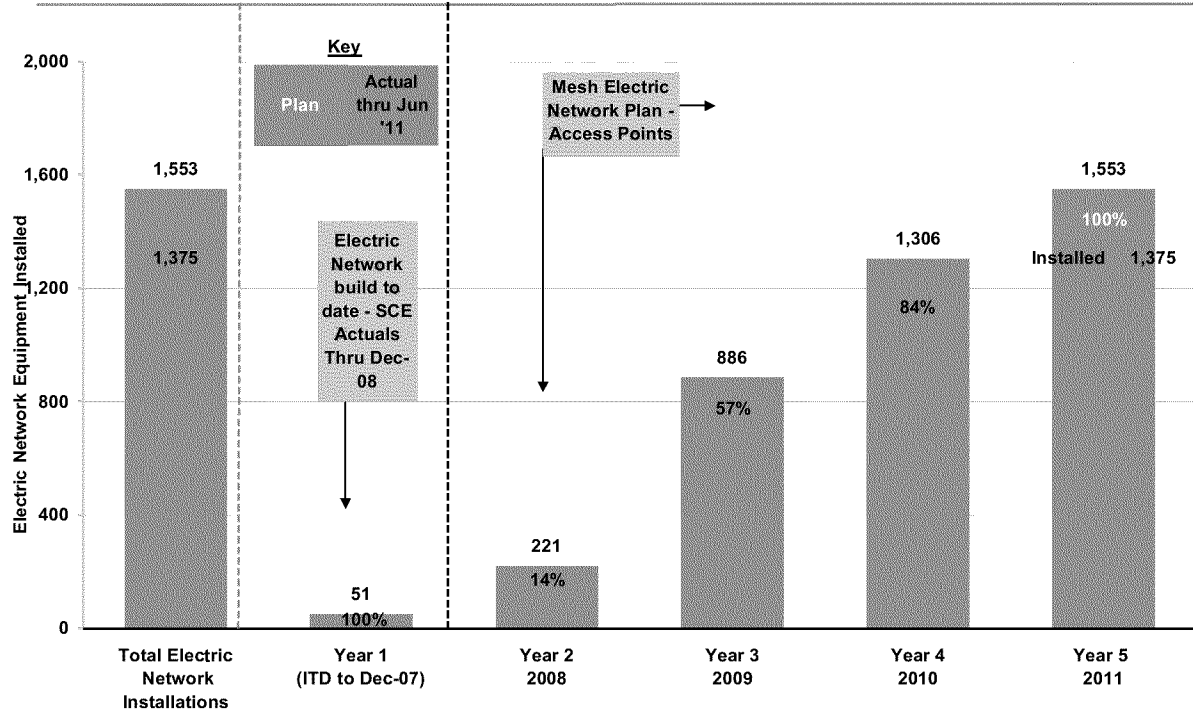
3 PG&E continues to make progress in the deployment of gas and electric network
 4 infrastructure, the installation of gas and electric meters and communication modules,
 5 and the activation of gas and electric meters.

6 The following figures summarize the progress of PG&E's SmartMeter™ Program
 7 implementation in each respective area through June 30, 2011. The percent-of-plan
 8 refers to the total (five-year) Program completion and provides perspective on PG&E's
 9 installation progress. PG&E reports actual and projected deployments and installations
 10 on a calendar year (CY) basis.

1 **Table III – 2**

2

Cumulative Electric Network Installations: Substation Communication Equipment (SCE) & RF Mesh Access Points



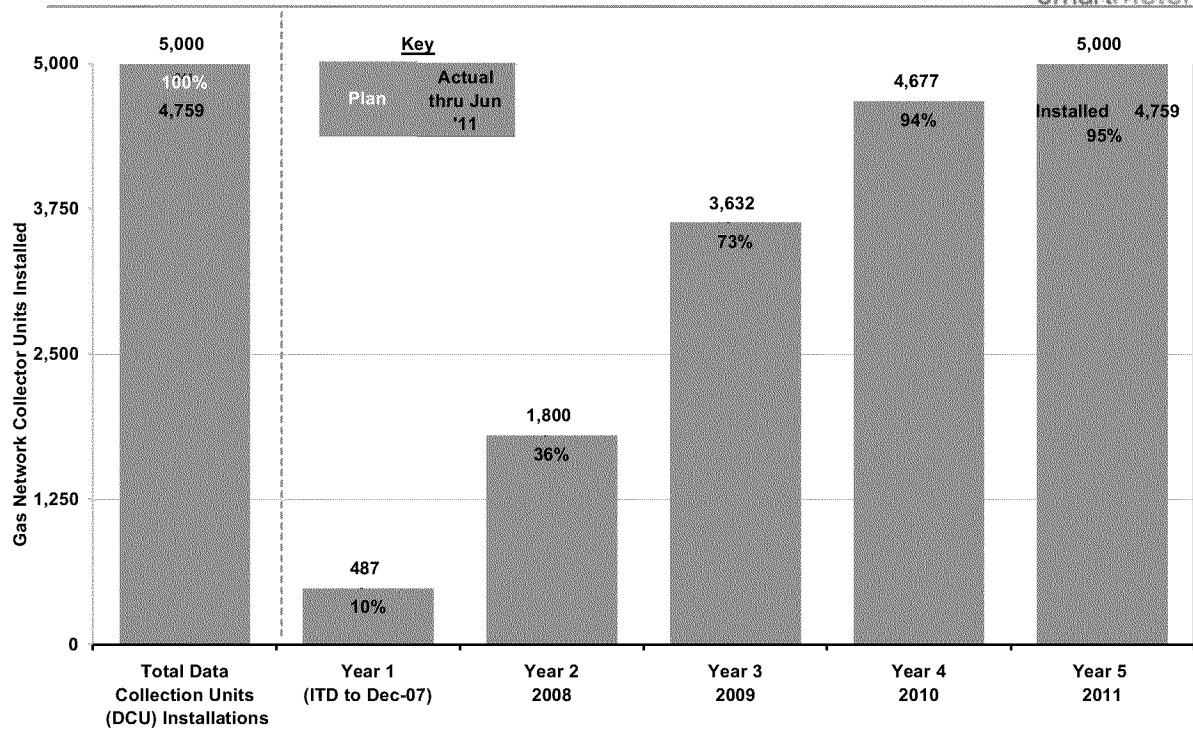
3

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

4

1 **Table III - 3**

Cumulative DCU Network Installations



2

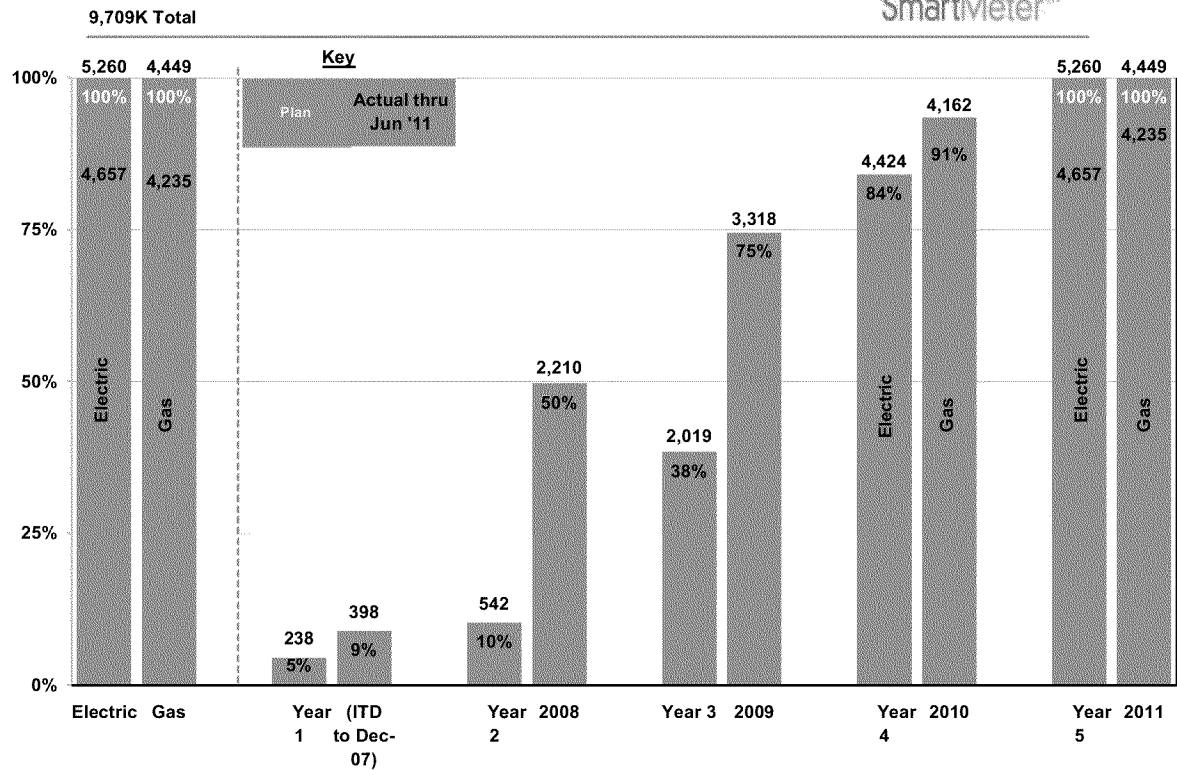
Cumulative Data Collection Unit (DCU) Installations	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Installed thru 06/11	4,759	487	1,800	3,632	4,677	4,759
Plan	5,000	487	1,800	3,632	4,553	5,000

3

1 **Table III - 4**

2

Cumulative Network Enabled Locations (in 000s)



3

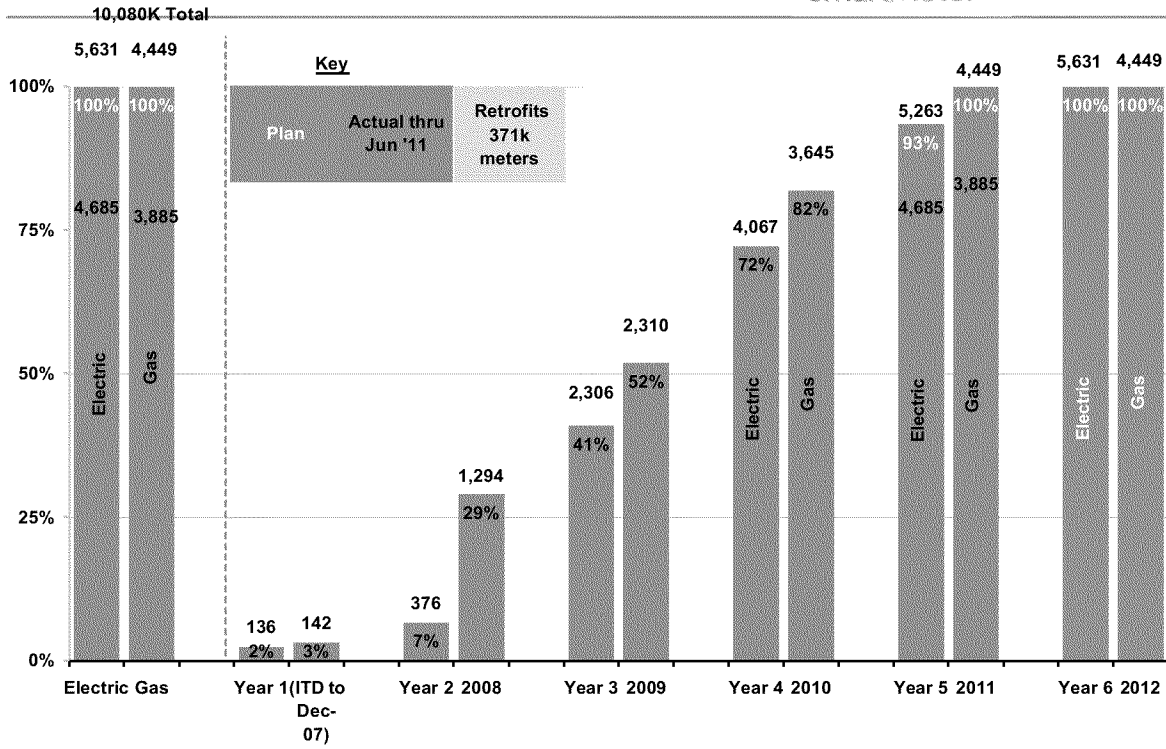
Cumulative Network Enabled Locations (000)	Total	2007		2008		2009		2010		2011	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Enabled thru 06/11	8,892K	238K	398K	542K	2,210K	2,019K	3,318K	4,424K	4,162K	4,657K	4,235K
Plan*	9,709K	238K	398K	542K	2,210K	2,019K	3,318K	4,722K	4,029K	5,260K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

4

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

1 **Table III - 5**

Cumulative Meter-Module Installations (in 000s)



2

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 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

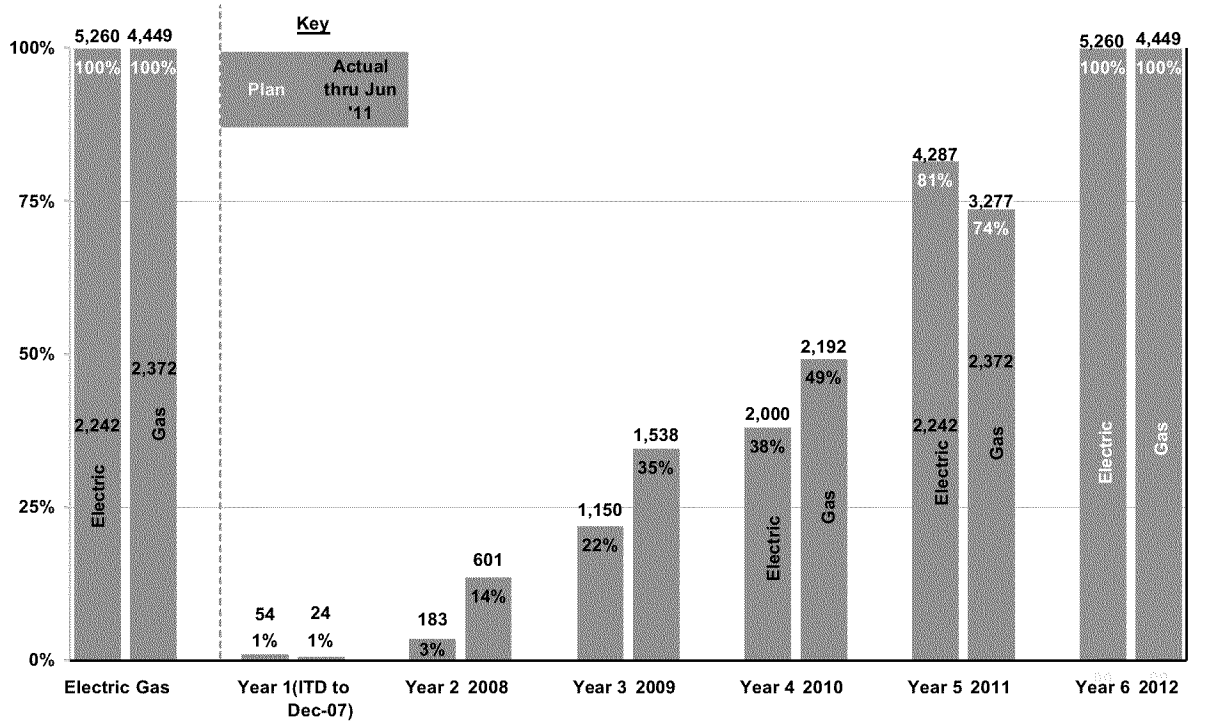
*Planned total includes installation of retrofitted SmartMeters™ and updated meter growth forecast through 12/31/10.

3

1 **Table III - 6**

Cumulative Meter-Modules Activated (in 000s)

9,709K Total



2

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.

3

1 **IV. Program Costs and Benefits**

2 A. SmartMeter™ Program Costs

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

8 The Program budget includes a risk-based allowance, which was authorized by the
9 CPUC to provide for unanticipated costs necessary to complete the defined Program
10 work scope. For the SmartMeter™ Program, only the officer-led Steering Committee
11 can approve a workstream expenditure that requires a draw against the risk-based
12 allowance funding category. If a draw against the risk-based allowance is approved, the
13 workstream budget is shown with an increase in approved funds, and the risk-based
14 allowance category with an equal offsetting amount. In addition, the PMO recommends
15 other reallocations, both increases and decreases, within and among workstream
16 budgets, as circumstances require. Table IV-1 indicates the approved adjustments to
17 the workstream budgets, which reflect both the allocation of the \$178 million risk-based
18 allowance and the additional \$129 million Board-approved costs.

19 Through June 30, 2011, the SmartMeter™ Program incurred costs of approximately
20 \$2,143 million (\$1,745 million in capital and \$398 million in expense). Of this total dollar
21 amount, Field Delivery activities have cost approximately \$1,411 million (66 percent)
22 and IT-related activities have cost approximately \$467 million (22 percent). The
23 remaining 12 percent is attributed to the Customer & SM Operations and PMO
24 categories. The Program's total estimated cost at completion of \$2,335 million is based

1 on the combined CPUC cost authorizations of the AMI Decision (\$1,739 million) and
 2 Upgrade Decision (\$467 million), as well as the additional \$129 million of Board-
 3 approved costs.

4

5 **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%	

6 Note: Totals subject to rounding

7 The Customer & SM Operations category includes \$54.8 million specifically
 8 authorized in the AMI Decision for the purpose of marketing Critical Peak Pricing
 9 programs. As of June 30, 2011, approximately \$28.4 million of the \$54.8 million has
 10 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

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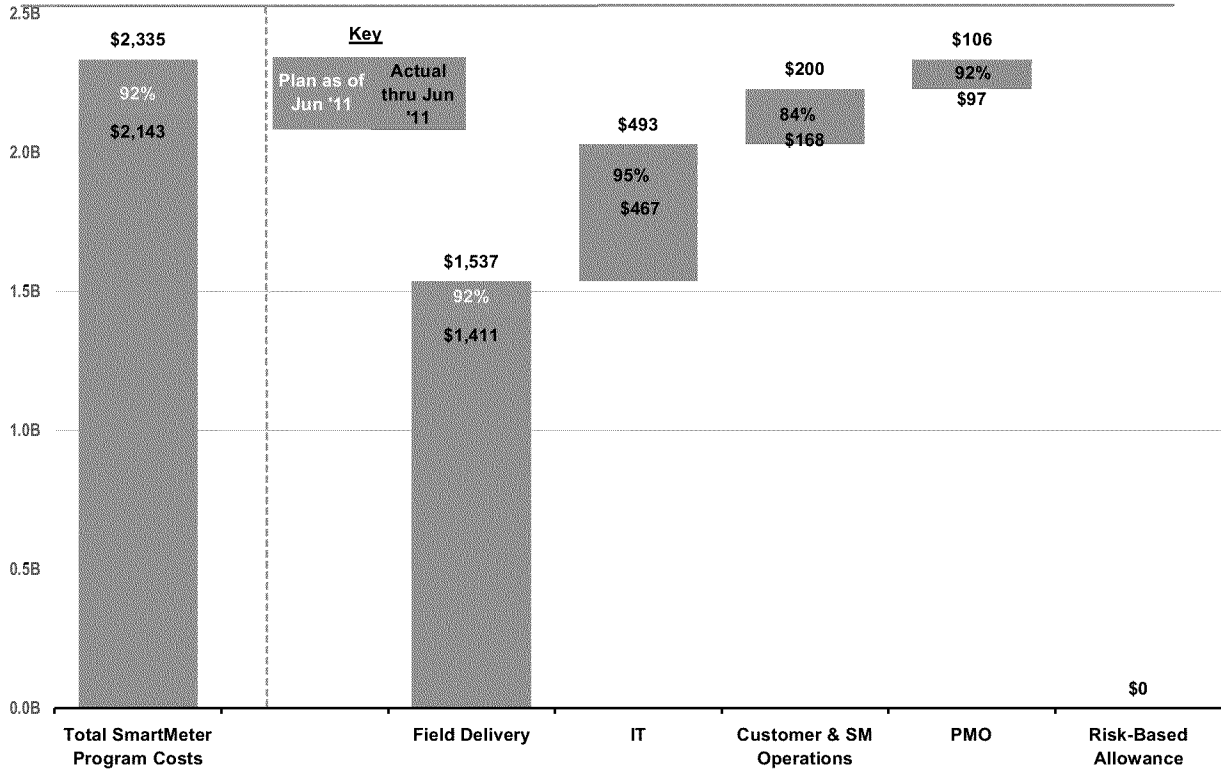
12 Tables IV-2 through IV-7 show PG&E's incurred costs from inception through June
 13 30, 2011, for the SmartMeter™ Program, as well as each respective budget category.
 14 The percent-of-expenditures refers to the total incurred expenditure as of June 30, 2011
 15 as a percentage of the adjusted workstream budgets.

16

1 **Table IV – 2**

2

Total SmartMeter™ Program Costs (\$ Millions)



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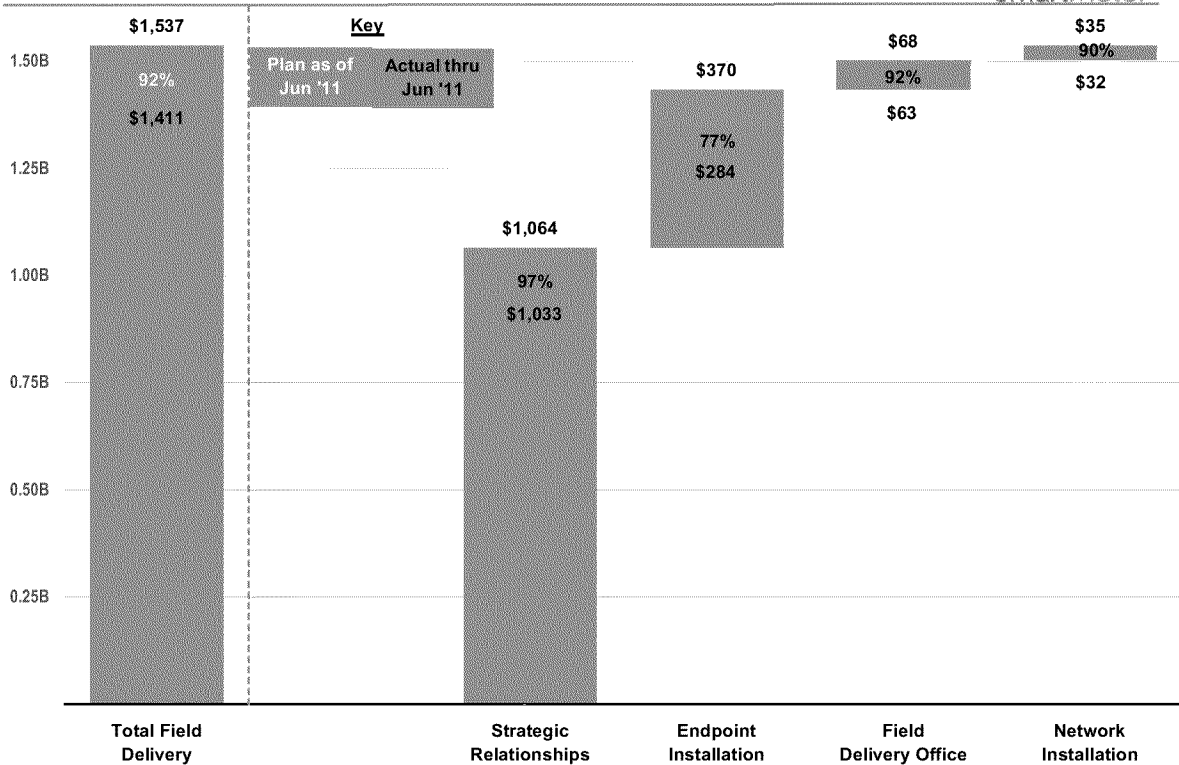
\$ Millions	Total SmartMeter Program Costs	Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allowance
Actuals thru June 30, 2011	2,143	1,411	467	168	97	N/A
Plan as of December 31, 2010	2,206	1,438	493	179	96	-
Cost Changes/Reallocation	129	99	-	21	10	-
Plan as of June 30, 2011	2,335	1,537	493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

Note: Totals subject to rounding

4

1 **Table IV – 3**

Field Delivery Costs (\$ Millions)



2

\$ 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%

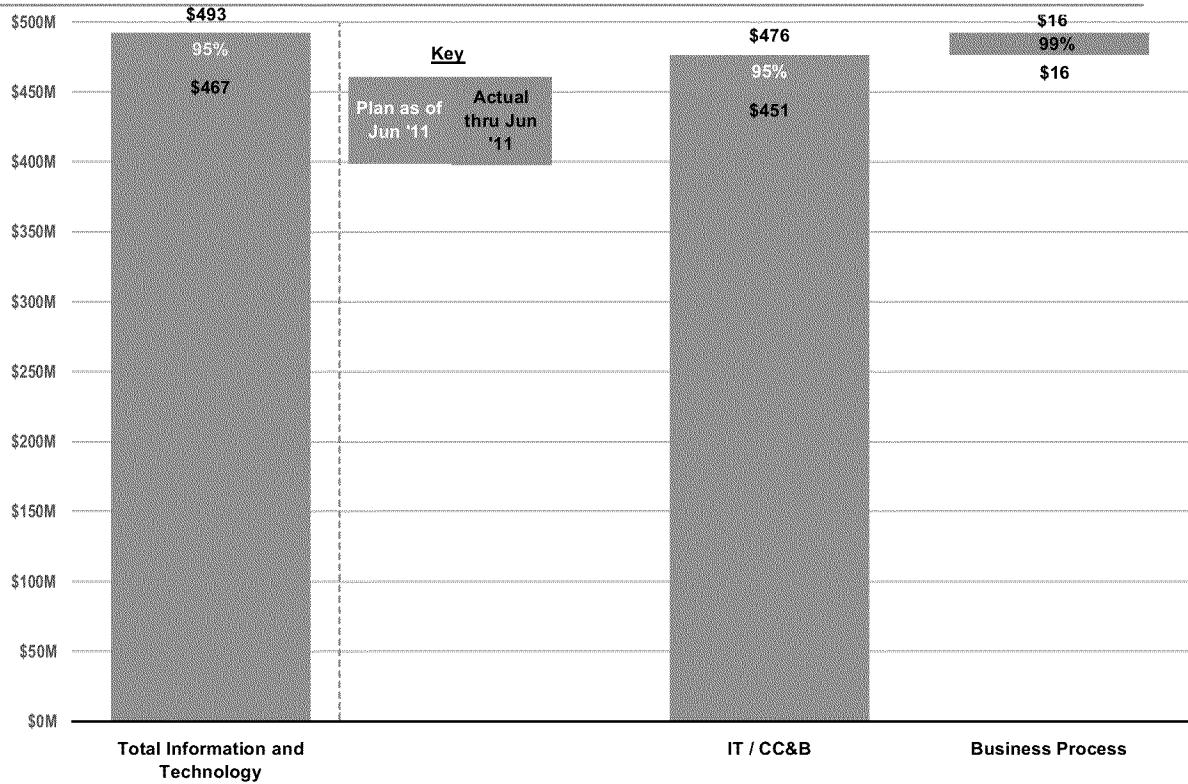
\$ Millions	Network Installation	Electric Network	Gas Network
Actuals thru June 30, 2011	32	20	11
Plan as of December 31, 2010	29	12	17
Cost Changes/Reallocation	6	12	(5)
Plan as of June 30, 2011	35	24	12
% of Plan Expended	90%	86%	97%

3

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.

1 **Table IV - 4**
2

Information Technology Costs (\$ Millions)



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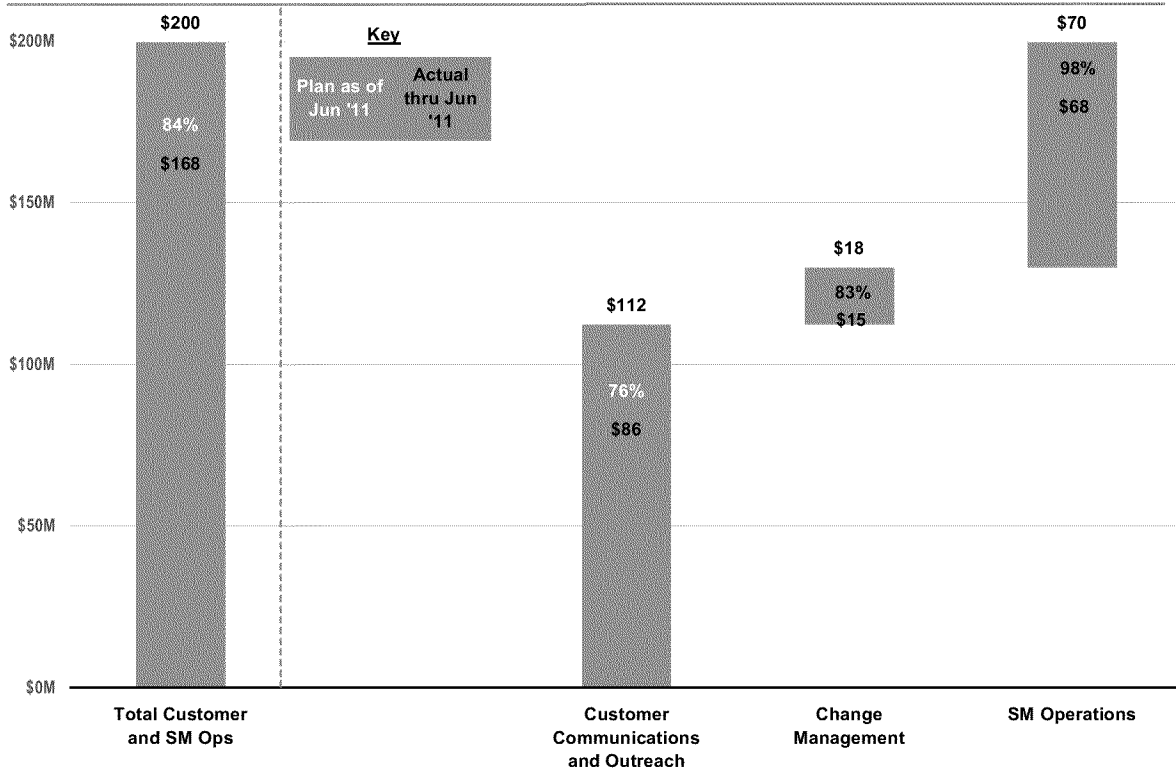
\$ Millions	Total Information and Technology	IT / CC&B	Business Process
Actuals thru June 30, 2011	467	451	16
Plan as of December 31, 2010	493	478	15
Cost Changes/Reallocation	(0)	(2)	1
Plan as of June 30, 2011	493	476	16
% of Plan Expended	95%	95%	99%

4

Note: Totals subject to rounding

1 **Table IV - 5**
2

Customer and SM Operations Costs (\$ Millions)



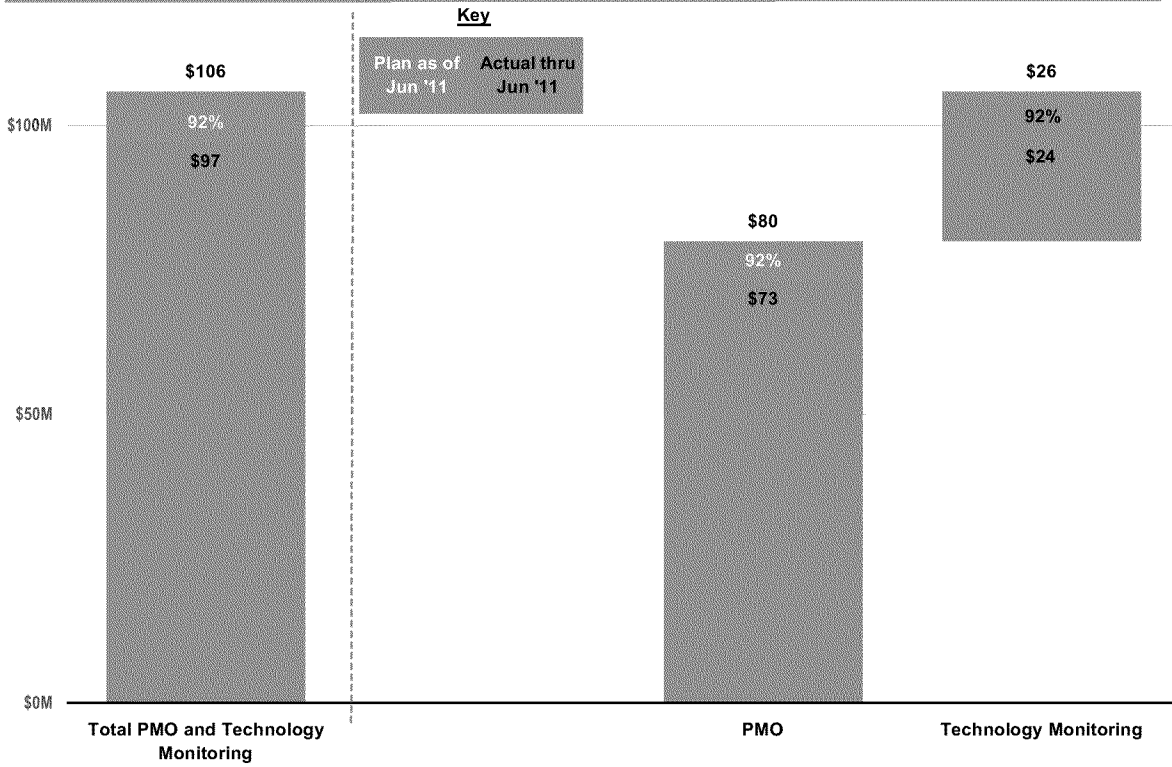
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\$ Millions	Total Customer and SM Ops	Customer Communications and Outreach	Change Management	SM Operations
Actuals thru June 30, 2011	168	86	15	68
Plan as of December 31, 2010	179	98	13	68
Cost Changes/Reallocation	21	14	5	2
Plan as of June 30, 2011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

5 Note: Totals subject to rounding

1 **Table IV - 6**
2

PMO & Technology Monitoring Costs (\$ Millions)



3
4

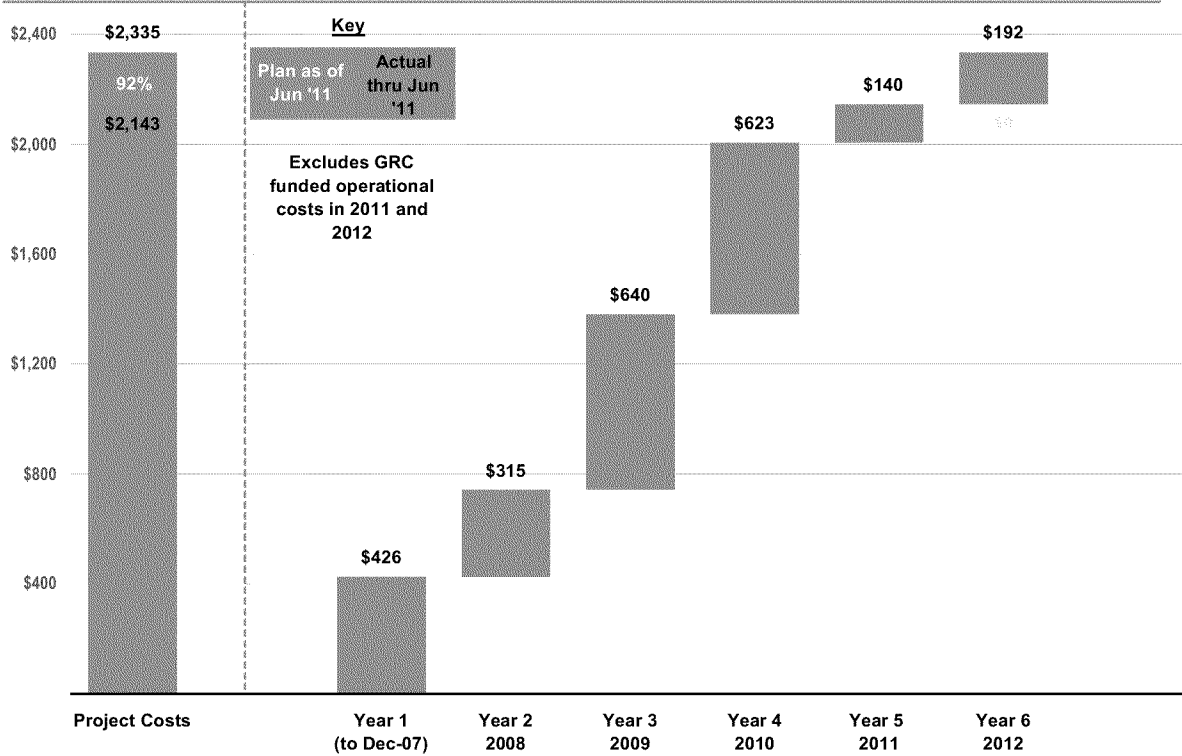
\$ Millions	Total PMO and Technology Monitoring	PMO	Technology Monitoring
Actuals thru June 30, 2011	97	73	24
Plan as of December 31, 2010	96	70	26
Cost Changes/Reallocation	10	10	(0)
Plan as of June 30, 2011	106	80	26
% of Plan Expended	92%	92%	92%

Note: Totals subject to rounding

5

1 **Table IV – 7**
2

Total SmartMeter™ Project Costs By Year (\$ Millions)



3

\$ 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

4

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

1 B. Operational Benefits Realization

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

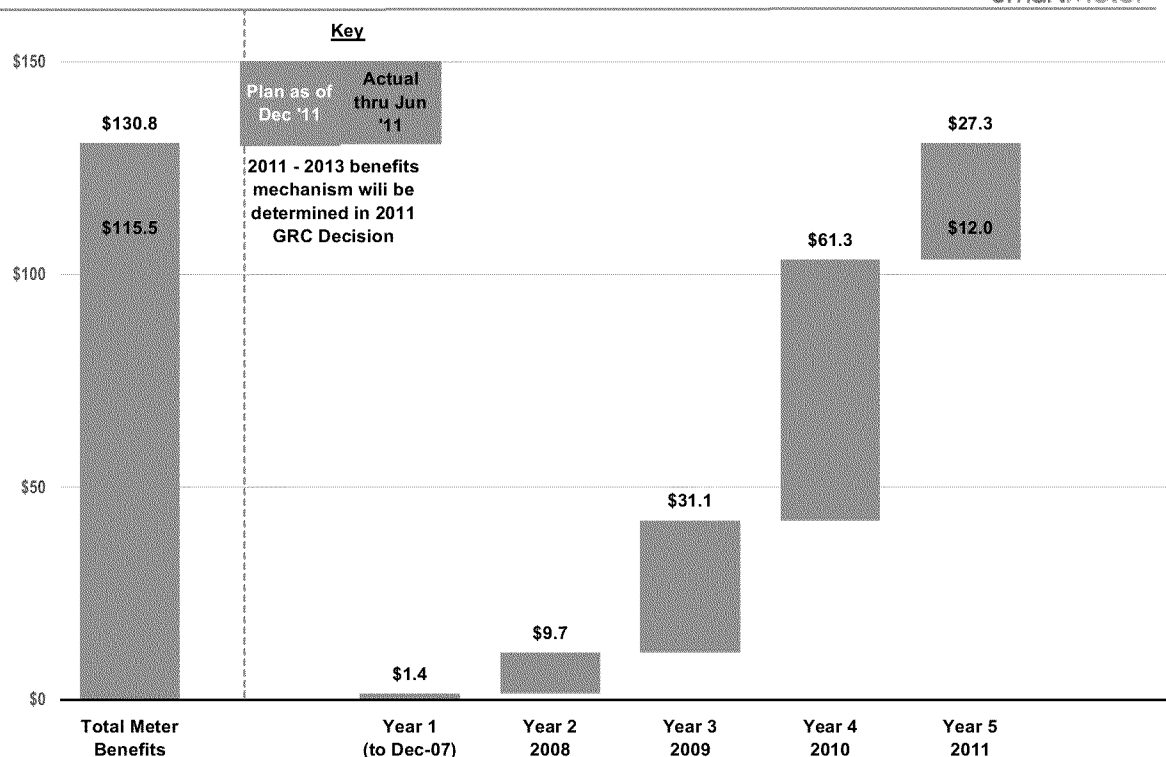
10 As reported in the January 2008 Report, the first meter activations occurred in
11 December 2007. Since then, approximately 7,409,000 meters have been transitioned,
12 and approximately 4,614,000 meters have been activated (as of June 30, 2011). Total
13 cumulative benefits recorded as credits to the balancing accounts as of June 30, 2011
14 are \$115.5 million, which represent both activated meter benefits and mainframe
15 software licensing benefits. Such amounts are consistent with the calculation
16 methodologies and savings rates adopted in the AMI and Upgrade Decisions, as well as
17 the 2011 GRC Decision.

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

- 1 activated meter benefits in effect since January 1, 2011, based on the 2011 GRC
- 2 Settlement, are \$0.9225 per meter per month for electric and \$0.0189 per meter per
- 3 month for gas.

4 **Table IV – 8**

Total Meter Benefits by Year (\$ Millions)



5

Activated Meter Benefit - Actuals (As of June 30, 2011)						
		<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>
(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

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

1 **V. System Performance Criteria Metrics**

2 System performance criteria and metrics are measured and reported on an on-going
 3 basis as meter installations progress. As stated in previous reports, PG&E may modify
 4 these criteria and metrics after it has collected and analyzed actual system performance
 5 parameters in order to better characterize system performance.

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

8 **Table V - 1**

9

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.		

10

11 The performance criteria presented in Table V-2 are based on the number of actual
 12 reads retrieved by the head-end system versus the expected number of reads provided
 13 by the system. Deployment in areas with poor communications coverage degrades
 14 performance, while firmware upgrades and supplemental network designs for existing
 15 and new installations improve performance. PG&E considers that the system performs
 16 as designed within the specified system requirements. Additionally, PG&E's monitoring
 17 of SmartMeter™ billing continues to indicate performance that meets and/or exceeds
 18 established criteria.

1 **Table V – 2**

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%

3

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

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

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

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

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

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

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

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

18 PG&E's SmartRate™ Program, a Critical Peak Pricing tariff option that requires
19 interval data to administer, was launched in May 2008. It supports a customer's ability
20 to manage energy usage during hot summer days when SmartDay™ events are
21 triggered when temperatures surpass a preset threshold. As of June 30, 2011, the
22 SmartRate™ Program had 22,930 active residential customers.

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

1 May 1, 2010. The transition of the non-residential customers from SmartRate™ to PDP
2 started in May 2010. The decision also ordered residential customers on SmartRate™
3 to default to PDP on February 1, 2011. PG&E requested, and was granted, an
4 extension to November 1, 2011 for residential customer transition. As a result, the
5 residential SmartRate™ Program was extended until October 31, 2011. On January 14,
6 2011, PG&E filed a Petition for Modification of Decision 10-02-032, asking the
7 Commission to delay the default of residential SmartRate™ participants to PDP and to
8 retain SmartRate™ as an option for residential customers until residential dynamic
9 pricing options are considered again by the Commission. The Executive Director
10 granted PG&E's request on May 5, 2011, but established a default date of November 1,
11 2012, pending the Commission's decision on PG&E's Petition for Modification.

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

- 16 • There were 13 SmartDays™ during the 2010 season (May 1 through October
17 31).
- 18 • On average, participants reduced peak electricity use by 16.9 percent across the
19 13 event days.
- 20 • August 2010 offered the season's highest average reduction – 17.4 percent – in
21 peak electric use.
- 22 • In general, participants with central air conditioning reduced peak electricity use
23 more than those without it.

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

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

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

- 9 • 81 percent of 2010 customers report being very satisfied with SmartRate™.
- 10 • A higher share of low-income respondents – 91 percent – reported being very
11 satisfied with SmartRate™.
- 12 • 79 percent of respondents perceived they were saving energy during their
13 SmartRate™ participation and more than 90 percent actually experienced lower
14 costs.
- 15 • 95 percent of 2010 SmartRate™ customers planned to continue on SmartRate™
16 in 2011.
- 17 • 88 percent of SmartRate™ customers would recommend SmartRate™ to a
18 friend.

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

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

8 **VII. SmartMeter™ Information Technology Progress**

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

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

- 20 • Release 1: July 2011
 - 21 • Remote Connect/Disconnect
 - 22 • 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.

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

14 **VIII. SmartMeter™ Transition to Operations**

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

22 Business departments that are directly affected by this transition and currently
23 receiving training include: Contact Center Operations, Office Services, Meter to Cash,
24 Service Planning, Gas and Electric Meter Shop, Restoration, Customer Field Services,

1 Energy Service and Solutions, Telecommunications, and Gas and Electric Maintenance
2 and Construction. Transition planning has begun with business departments, with
3 transitions beginning as early as March 2011 and continuing through the end of
4 deployment. In parallel with these activities, Employee Change Management is
5 partnering with Information Technology, Governmental Relations, and Internal and
6 External Communication departments to ensure employees are well-prepared ahead of
7 implementation.

8 **IX. Other Program Updates**

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

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

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