Application: 11-11-XXX
(U 39 E)
Exhibit No.: ____________________
Date: November 21, 2011
Witnesses: Various

PACIFIC GAS AND ELECTRIC COMPANY

SMART GRID PILOT DEPLOYMENT PROJECT

PREPARED TESTIMONY

PG&E®

PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID PILOT DEPLOYMENT PROJECT
PREPARED TESTIMONY

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

SMART GRID PILOT DEPLOYMENT PROJECT POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
SMART GRID PILOT DEPLOYMENT PROJECT POLICY

TABLE OF CONTENTS

SB_GT&S_0303974

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
SMART GRID PILOT DEPLOYMENT PROJECT POLICY

A. Introduction

In this application, Pacific Gas and Electric Company (PG&E) requests that California Public Utilities Commission (CPUC or Commission) approve its proposal to implement the Smart Grid Pilot Deployment project. This project seeks to advance the modernization of PG&E's electric grid consistent with the policy of the state of California as described in Senate Bill 17[1] (SB 17) and PG&E's Smart Grid Deployment Plan (Deployment Plan) filed with the Commission on June 30, 2011.[2]

PG&E's Smart Grid Pilot Deployment project will test, evaluate and deploy select technologies and initiatives on a pilot basis which when fully deployed, if results indicate that full deployment is appropriate, could provide significant value to PG&E's customers in the form of energy cost savings, reduced environmental impacts, avoided Operations and Maintenance (O&M) costs, as well as improved service reliability and enhanced safety. In this application, PG&E is requesting **$109 Million ($77 million capital, $32 million expense)** from 2013 through 2016 with an associated revenue requirement of approximately **$39 million** over the same period.

As stated in SB 17, "It is the policy of the state to modernize the state's electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with an infrastructure that can meet future growth in demand and achieve all of the following, which together characterize a smart grid:

a. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

b. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security.

---

[1] Stats. 2009, Ch. 327.

[2] Application 11-06-006.

c. Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

d. Development and incorporation of cost-effective demand response, demand-side resources, and energy-efficient resources.

e. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation.

f. Integration of cost-effective smart appliances and consumer devices.

g. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning.

h. Provide consumers with timely information and control options.

i. Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.

j. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services."

In its Smart Grid Deployment Plan, PG&E described 21 new initiatives that it plans to pursue over the next 10 years to provide benefits to its customers and to meet California's energy policy goals as outlined in SB 17 and other legislative requirements. In this application, PG&E is seeking authorization and cost recovery to begin work on six of these new initiatives.

Decision 10-06-047 provides the utilities with the option to seek approval of Smart Grid investments through individual applications or through General Rate Cases (GRC).[3] The six initiatives for which PG&E is seeking approval in this application require early stage development work now to provide customers with the benefits sooner than if PG&E were to wait until 2014, the Test Year for its next GRC, to begin the evaluation.

As will be described further in this chapter and later in this application, the six initiatives have the potential to provide significant benefits upon full deployment to customers in the form of avoided energy procurement costs,

[3] See Decision 10-06-047, Ordering Paragraph 14.

reduced environmental impacts, avoided O&M costs, improved service reliability and enhanced public safety. If the projects were to be deployed at the scale described in PG&E's Deployment Plan, collectively, these projects and initiatives could achieve approximate benefits over 20 years of:

- $550 million to $1.1 billion in avoided energy procurement costs
- $80 million to $110 million in avoided O&M costs
- 5 to 9 percent improvement in system reliability[4]
- 1.6 to 2.2 million metric tons of avoided carbon dioxide emissions[5]

In addition to the quantified potential benefits listed above, these initiatives may support enhanced public safety by identifying hard to detect high impedance fault conditions and advance California's progressive energy policy goals by supporting the interconnection of higher levels of distributed, solar photovoltaic generation and other intermittent resources.

The potential customer benefits associated with large-scale deployment of the technologies identified in this application are significant. However, PG&E believes additional testing and piloting on PG&E's system is necessary to confirm the estimated benefits before seeking approval for the capital investment necessary to achieve these potential benefits.

Beginning now with the testing and piloting rather than including these projects in PG&E's 2014 GRC could allow deployment of the specific initiatives beginning in 2017 assuming the expected benefits are shown to be achievable. Including the initial initiative testing and evaluation work in its 2014 GRC could delay large scale benefits until 2020 due to the timing of PG&E's GRC cycle.

B. Regulatory Background

In response to the Federal Energy Independence and Security Act of 2007, on December 22, 2008, the Commission initiated Rulemaking 08-12-009, the Smart Grid Order Instituting Rulemaking (OIR). This OIR set out to examine the Commission's policies with respect to modernizing the electric grid. Soon after the Smart Grid OIR was initiated, the federal government passed the American Recovery and Reinvestment Act (ARRA) in 2009 that proposed substantial

---

[4] Percent improvement in System Average Interruption Duration Index.

[5] 2011-2030 study period, internal PG&E estimates.

investment in grid modernization and new technology development to advance the Smart Grid. Later in 2009, SB 17 was signed into law in California outlining the state's policies for modernizing the electric system, describing the characteristics of a smart grid and setting in motion the process by which the utilities, interested parties and the Commission should undertake in achieving these state policies, including implementation of the utilities' Smart Grid Plans filed with the Commission under those policies.

C. Summary of PG&E's Proposed Smart Grid Deployment Plan

PG&E's Smart Grid Deployment Plan adopts ***10 high-priority Smart Grid strategic objectives in four program areas*** to guide PG&E's Smart Grid investments and initiatives over the next decade and to achieve the Smart Grid policies and goals established by SB 17:

Engaged Consumers

1. **Leverage SmartMeter™ Technology for Direct Customer Benefit** – This strategic objective is to take advantage of the SmartMeter™ capability to stimulate industry-wide innovation, and implement programs, standards and technologies that can be used by customers and by third parties to create and provide energy solutions and tools for customers.
2. **Improve the Use of Demand Response Resources for Operational Efficiency** – This strategic objective is to enable better use of demand response resources in energy and ancillary service markets and thereby increase the efficient use of these resources and reduce the environmental impact of supply-side energy resources.
3. **Support the Expanding Market for Electric Vehicles** – This strategic objective is to appropriately invest in the necessary Transmission and Distribution infrastructure and monitoring systems to accommodate and support the mass market adoption of electric vehicles.

Smart Energy Markets

1. **Improve the Forecasting of Market Conditions** – This strategic objective is to improve the ability to match energy supplies and energy demand while maintaining the reliability of the grid and increasing the use of renewable energy to meet statutory requirements.
2. **Integrate and Manage Large-Scale Renewable Resources** – This strategic objective is to enhance PG&E's ability to integrate large-scale

renewables into the grid in order to allow for more widespread deployment of clean resources and technologies that reduce the carbon footprint of PG&E's generation portfolio while maintaining energy system reliability.

Smart Utility

1. **Enhance Grid Outage Detection, Isolation, and Restoration** – This strategic objective is to leverage advanced communications technology and control systems to assist utility operators and repair personnel to locate damaged equipment or outage areas, isolate the problem and restore service to unaffected areas quickly, thereby minimizing customer outage time.
2. **Enhance Grid System Monitoring and Control** – This strategic objective is to deploy advanced monitoring and control technologies to provide more in-depth understanding of grid equipment and conditions to identify emerging problems before they result in system disruptions.
3. **Manage Grid System Voltage and Losses** – This strategic objective is to use advanced technologies to enhance PG&E's capability to maintain voltage levels within required levels, and to use the same sensing, telecommunications and control systems to reduce energy usage by customer equipment and reduce electric losses in the utility delivery system and reducing costs for customers.
4. **Manage Transmission and Distribution Asset Condition** – This strategic objective is to improve the utility's ability to monitor real-time asset conditions in substations, which will help improve operational efficiency as well as provide advanced warning of potential issues that can result in equipment failures.

Foundational and Cross-Cutting Smart Grid Infrastructure

1. Provide Foundational and Cross-Cutting Utility Systems, Facilities and Programs Necessary to Continuously Improve the Application of New Smart Grid Technologies – This strategic objective is to improve the foundational and cross-cutting systems and programs in information technology, telecommunications, and cyber security; technology testing, evaluation and standards development; workforce development; and customer engagement that are necessary in order to achieve PG&E's other Smart Grid strategic objectives.

The 10 strategic objectives align with California's grid modernization policies described in SB 17 cited earlier in this chapter.

D. Description of the Smart Grid Pilot Deployment Projects Included in This Application

This immediate application seeks approval to begin work on six important Smart Grid initiatives with significant potential benefits to customers, but which require additional development and benefits verification before seeking approval for the associated capital investments for full-scale deployment. PG&E's proposed initiatives also include necessary investments in Information Technology (IT) (software applications, cyber security, data management architecture, hardware and telecommunications). The project proposes to reduce technology implementation risk by focusing IT support on the testing and pilot stages while also performing analysis and high level design of foundational infrastructure to support the full scale deployments if the pilots prove to be successful. This approach minimizes costs and avoids unnecessary investments in large scale Smart Grid foundational IT infrastructure until after the benefits have been proven, while at the same time expediting the high level IT design work in preparation for scaled-up deployment of these projects.

The specific initiatives and potential benefits are described briefly below and in more depth in later chapters in this application.

1. Smart Grid Line Sensors

In this pilot project, PG&E will install line sensors to evaluate their impact on reducing outage response time, improving outage location accuracy, and the ability to provide line loading information at the installed locations. To achieve this goal, following a testing and evaluation phase, PG&E will pilot recommended line sensors on up to 30 distribution feeders in three PG&E divisions. This pilot may also include evaluation of various communication technologies to support the line sensor operation including cellular, mesh radio and existing distribution automation telecommunications networks.

This project supports advancing PG&E's Smart Grid strategic objectives in its Smart Utility program to: (1) enhance grid outage detection, isolation, and restoration; and (2) enhance grid system monitoring and control and is consistent with SB 17 Smart Grid characteristics of improved reliability of the electric system.

2. Voltage and Reactive Power (Volt/VAR) Optimization

In this pilot project, PG&E seeks to test voltage and reactive power (VAR) optimization algorithms and control systems on up to 12 distribution feeders in three PG&E divisions, to control one or all of the following voltage and reactive power regulating devices on PG&E's distribution system: (1) substation load tap changers, bus or feeder voltage regulators; (2) distribution line regulators; and (3) distribution line capacitors to achieve electricity demand and energy use reductions, voltage profile improvements and power system loss reductions. The optimization algorithms and control systems will use voltage measurements from SmartMeters™, and other substation and line equipment with voltage sensing information to adjust the distribution system voltage levels.

This project supports advancing PG&E's Smart Grid strategic objectives in its Smart Utility program to: (1) enhance grid system monitoring and control; and (2) manage grid system voltage and losses and is consistent with SB 17 smart grid characteristics of: (a) improved grid efficiency; (b) dynamic optimization of grid operations and resources; and (c) integration of distributed resources.

3. Detect & Locate Distribution Line Outages and Faulted Circuit Conditions

In this pilot project, PG&E will test system analysis tools to more precisely locate outages and faulted circuit conditions caused by damaged equipment using input from a variety of sensors including digital protective relays, fault current sensors, SmartMeter™ voltage measurements and Smart Grid line sensors. During the pilot phase of this project, PG&E will install fault-finding software systems and telecommunication systems on up to 15 distribution feeders in two of PG&E divisions.

This project supports advancing PG&E's Smart Grid strategic objectives in its Smart Utility program to: (1) enhance grid outage detection, isolation, and restoration; and (2) enhance grid system monitoring and control; and is consistent with SB 17 Smart Grid characteristics of improved reliability of the electric system.

4. Short-Term Demand Forecasting

The objective of this pilot project is to evaluate if more granular sources of data can be acquired and used cost-effectively to improve the accuracy of short-term demand forecasts for PG&E's bundled customers, which inform daily electricity procurement activities. These more granular sources of information are SmartMeters™, transmission and distribution network devices, demand response programs, and other sources.

This project supports advancing PG&E's Smart Grid strategic objectives in its Smart Markets program to assess the value of improving forecasting of market and portfolio conditions, and is consistent with SB 17 Smart Grid characteristics of increased use of digital information to improve the reliability and efficiency of the grid.

5. Technology Evaluation, Standards and Testing

PG&E will also seek to create a Smart Grid technology development capability to integrate and test new Smart Grid technologies, evaluate and develop Smart Grid standards, and improve PG&E's understanding of new Smart Grid technologies through the benchmarking of experiences of others. This initiative will also focus on investigating ways to use information created by Smart Grid systems including SmartMeters™ to create new or improved regulated utility services for customers to leverage the extensive investments already in place. This initiative will also investigate the applicability of new technologies being tested or deployed by other utilities to PG&E's systems including projects being developed using ARRA Smart Grid grants or in National Laboratories across the country.

This initiative supports advancing PG&E's Smart Grid strategic objectives in its Foundational and Cross-Cutting program to put in place programs necessary to continuously improve the application of new Smart Grid technologies. It is also consistent with virtually all of the SB 17 Smart Grid characteristics and specifically supports developing standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid. The work to be performed under this initiative will build on the knowledge base and research results already obtained through PG&E's existing technology evaluation, testing and innovation programs, including those funded under PG&E's general rate cases and SmartMeter™ program.

6. Smart Grid Customer Outreach

PG&E's proposal also includes an initiative to perform regional and community level customer outreach to engage our customers in understanding Smart Grid facts, costs and benefits at the individual and societal level, including with the five projects described in this application and other Smart Grid related projects as appropriate. This outreach is intended to support customers using Smart Grid enabled tools to make informed energy choices and to understand the Smart Grid capabilities being deployed.

This initiative supports advancing PG&E's Smart Grid strategic objectives in its Foundational and Cross-Cutting program to provide utility facilities and programs necessary to continuously improve the application of new Smart Grid technologies. This initiative also focuses on the customer education, awareness and engagement in the Smart Grid components that are necessary to achieve PG&E's other Smart Grid strategic objectives and is consistent with virtually all of the SB 17 Smart Grid characteristics involving consumers directly.

E. Summary of Cost and Revenue Requirement Requested

1. Project Cost Summary

Table 1-1 below provides a summary of the estimated costs for each of the six projects contained in this application along with the associated annual revenue requirement.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID PILOT DEPLOYMENT PROJECT
SUMMARY OF PROJECT EXPENDITURE
($ IN THOUSANDS)

Line No.	Project	2013	2014	2015	2016	Total
1	Smart Grid Line Sensors	$2,551	$8,681	$3,023	$2,652	$16,908
2	Volt/VAR Optimization	3,856	14,944	10,281	9,747	38,828
3	Detect & Locate Faults	1,733	8,224	1,547	1,506	13,009
4	Technology Evaluation Standards & Testing	2,306	3,587	3,585	2,973	12,451
5	Short Term Demand Forecasting	2,575	7,171	2,174	2,228	14,149
6	Customer Outreach & Awareness	3,031	3,231	3,458	3,795	13,515
7	Total Project Cost	$16,053	$45,838	$24,068	$22,901	$108,860
8	Revenue Requirements	$5,992	$7,667	$94	$25,138	$38,891

2. The Costs Proposed in this Application are Incremental

PG&E applied a two-step approach to test the incremental nature of each cost estimate included in the Smart Grid Pilot Deployment Project. Specifically, the analysis considered: (1) the incremental nature of the activities underlying the cost estimates in this Smart Grid Pilot Deployment Application; and (2) the incremental nature of the cost estimates relative to costs previously approved by the Commission in prior relevant proceedings.

In the first step, PG&E assessed whether the functionality or other factors giving rise to the estimated costs are incremental to:

(a) the activities that PG&E is currently undertaking.

(b) the functionality that already exists in PG&E's current systems and IT applications.

(c) other factors or functions that PG&E has requested and are either pending approval or approved by the Commission in previous proceedings.

Where the specific activity or function giving rise to the cost estimate has not previously been requested by PG&E or approved by the Commission in prior proceedings, PG&E performed the second step described below.

In the second step, PG&E assessed whether the specific components of the estimated costs (i.e., labor, materials, equipment and contracts) are additive to the costs included in PG&E's prior applications.

In order for costs to be considered incremental, the cost estimates must satisfy both steps. Using this process, PG&E determined that the costs included in this application are incremental to any costs approved for recovery or pending before the Commission.

F. Timeline for Implementation and Case Schedule

PG&E proposes that the six initiatives be tested and piloted over a four-year period beginning immediately following the final decision on this application. The specific schedule for each initiative will vary but, in general, the first two years will be devoted to analyzing and testing the technologies in a laboratory environment followed by a two-year pilot in a real or simulated operating environment. This schedule will provide PG&E sufficient information about the actual costs and benefits in time to propose continuing to larger scale deployment to achieve the targeted customer benefits in either its 2017 GRC or a separate application, or to discontinue project development based on its findings about costs and benefits.

In order for PG&E to meet this schedule, the Commission should approve PG&E's Smart Grid Pilot Deployment Program by no later than the end of 2012.

G. Overview of Testimony

The remaining testimony is organized as follows:

Chapter	Chapter Title	Witness
2	Smart Grid Distribution Pilot Projects	Dan Pearson
3	Technology Evaluation, Standards and Testing	Kevin Dasso
4	Short-term Demand Forecasting Smart Grid Pilot Project	Daidipya Patwa
5	Smart Grid Customer Outreach and Education Pilot	Steven Propper
6	Results of Operation	Niel Jones
7	Cost Recovery Proposal	Teresa Hoglund

H. Conclusion

In this application, PG&E is seeking authorization and cost recovery of $109 million to pursue early stage development of six Smart Grid initiatives that have the potential to provide significant benefits to its customers, modernize PG&E's electricity grid, and meet California's progressive energy and environmental policy goals in a logical and stepwise fashion. PG&E's application recognizes that testing and piloting of promising technologies and approaches is warranted before making the substantial long-term investments that require significant expenditures. In addition, PG&E's application proposes to pursue promising initiatives as quickly as possible rather than delay the realization of potential benefits for customers, a situation that would occur under GRC schedules.

The initiatives proposed in this application represent new technologies to modernize the electric utility infrastructure. Consistent with the concept of the Smart Grid, these initiatives include a much higher reliance on information technology than what many utilities have implemented in the electric system in the past. Therefore, the proposed testing and evaluation approach reflects an emphasis on both the grid and operations analysis combined with supporting information technology design and analysis. The deeper integration of information technology into the domain of electric utility operations requires evaluation and testing to validate the IT foundational requirements and to ensure that if projects progress to production deployment, there is a high degree of confidence of fully functioning, end-to-end reliable business and technology processes.

Even more importantly, this evaluation and testing is required to ensure customers will receive the full benefits of technology integration, including more reliable, environmentally sustainable and cost-effective utility service than would otherwise be provided by existing technologies.

PG&E's Smart Grid Pilot Deployment Project is consistent with PG&E's Smart Grid Deployment Plan and California's Smart Grid policies, and will cost-effectively demonstrate significant potential operating and environmental benefits for PG&E's customers. The Commission should approve PG&E's Program as proposed in this application.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

SMART GRID DISTRIBUTION PILOT PROJECTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
SMART GRID DISTRIBUTION PILOT PROJECTS

TABLE OF CONTENTS

TABLE OF CONTENTS

(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
SMART GRID DISTRIBUTION PILOT PROJECTS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) Smart Grid Distribution Pilot Projects under its Smart Grid Pilot Deployment Project and the forecast incremental costs and benefits associated with those projects. PG&E proposes to deploy on a pilot basis three separate distribution projects that will demonstrate different Smart Grid technologies that can be used to increase reliability, reduce costs, reduce environmental impacts of electric system operation, and more effectively, integrate distributed renewable generation on PG&E's distribution system. These projects are:

(1) Smart Grid Line Sensors

(2) Voltage and Reactive Power (Volt/Var) Optimization (VVO)

(3) Detect and Locate Distribution Line Outages and Faulted Circuit Conditions

The analysis, testing and piloting of these projects on PG&E's distribution grid will allow PG&E to understand and demonstrate the costs and benefits of these Smart Grid applied technologies prior to implementing a larger scale system deployment.[1] This is consistent with PG&E's Smart Grid strategy in its Smart Grid Deployment Plan, which provides for the Company to reduce the risk of implementing technologies new to PG&E and confirm the feasibility and reliability of those technologies in a pilot environment prior to larger scale production deployment across PG&E's system.

Each of these proposed projects is new and incremental to PG&E's baseline Smart Grid projects, as described in Chapter 4 of PG&E's Smart

[1] Chapter 7 of PG&E's Smart Grid Deployment Plan filed on June 30, 2011 presented both conceptual and provisional costs and benefits estimates quantifying the cost and benefits of the Smart Grid Projects and Initiatives laid out in the Deployment Plan.

Grid Deployment Plan. However, each project builds on and incorporates the know-how and insights from those baseline projects.

2. Summary of Project Costs

PG&E requests that the California Public Utilities Commission (CPUC or Commission) adopt its incremental capital and expense expenditure forecast for these Smart Grid Distribution Pilot projects.

The costs of the Smart Grid Distribution Pilot Projects are summarized in Table 2-1 as follows:

TABLE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID DISTRIBUTION PILOT PROJECT COSTS
($ IN THOUSANDS)

Line No.	Title	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	Total
1	Total Capital	$8,140	$31,246	$13,031	$11,905	$64,323
2	Total Expense	–	603	1,819	2,000	4,422
3	Total	$8,140	$31,849	$14,850	$13,905	$68,745

3. Support of Project Benefits

PG&E's three Smart Grid Distribution Pilot Projects will provide the following overall benefits:

- The **Smart Grid Line Sensor project** will install line sensors on up to 30 distribution feeders on the overhead and underground distribution primary system to test line sensor capabilities to communicate when a fault is detected and provide current flow data to operations and planning engineers. The line sensors provide more accurate information about the fault location area allowing faster outage restoration by reducing outage response time and improve customer satisfaction. The line sensors provide accurate current flow information to operators and engineers to plan and reconfigure the system without overloading equipment based on actual current measurements instead of models and more accurate current flow information to planning engineers to support better planning of the distribution system rather than relying on models. Line sensors provide more granular, location-specific information than conventional protection devices that operate under fault conditions since the sensors are located beyond the protection devices. This more granular, area specific information allows operators to more quickly direct physical line patrols to find damaged equipment that caused the fault. Line sensors also provide more accurate information about an outage area than SmartMeter™ outage reporting. SmartMeters™ provide operators information about the number of customers out of service and which automatic protective device operated to isolate damaged equipment. Line sensors can more precisely locate the area of the equipment damage within the larger outage area reported by SmartMeters™ allowing operators to direct personnel to this smaller area for patrolling and targeted investigation in a more expedited manner.

- The **Voltage and Reactive Power (Volt/Var) Optimization project (VVO)** is an automated distribution control system that communicates via traditional Supervisory Control and Data Acquisition (SCADA) system equipment to distribution line devices that will control the voltage on the distribution feeder, optimizing operating voltage and reactive power resulting in reduced customer energy usage and reduced utility system losses by more precisely managing the distribution voltage from the substation to the customer's service point (distribution primary, secondary and service systems). Feeders with high penetration of distributed renewable generation will also be selected in the pilot phase of the project to determine how to improve the management and integration of intermittent distributed generation sources, such as solar photovoltaic (PV) systems, which can adversely impact the feeder voltage profile. Solar PV systems can cause high voltage conditions when power output from these generators is at the maximum, adversely impacting operation of the PV systems as well as impacting other non-PV customers in the area. To the extent that the pilot project demonstrates the ability to reduce voltage and line losses, customer cost savings are possible. To the extent that the pilot project demonstrates the ability for the distribution system to support greater amounts of distributed generation, additional renewable generation will be enabled without the need for costly distribution system enhancements.

- The **Detect and Locate Distribution Line Outages and Faulted Circuit Conditions project** will install and evaluate fault finding software system or systems for use in the distribution operations control room with inputs from distribution circuit relays on the magnitude of fault current. This will assist in further pinpointing the location of failed equipment that caused an outage and determine if there are incremental benefits of providing this more accurate location. The software system will take the fault data supplied by the distribution circuit relay and compare it to the calculated software program fault duty and identify the likely faulted area within a more specific, determined distance. The fault location distance will be confirmed in the analysis, test and field pilot phase of the project. The distribution circuit protective relays provide information about the type of fault (line to line, line to ground) and magnitude of the fault current. If the pilot is successful, PG&E will incorporate other devices that provide outage and fault locating information into the software to assist in further narrowing the physical location of outage-causing faults to reduce outage time for customers and reduce outage management and response costs.

In addition, the combination of this fault analysis software with line sensors and voltage sensing devices, possibly including SmartMeters™, may be able to locate high-impedance faults in order to improve public safety. An example of a high-impedance fault is a conductor that breaks, but does not make a solid contact with the ground, resulting in an energized high-voltage line close to the ground presenting a hazard to the public. Existing protection equipment cannot detect these conditions in some cases because the fault current may not reach the level to cause the protective devices to operate.

Generally, there are multiple locations on each feeder that can have the same fault duty and, in these cases, the computer software system will provide all these locations. The line sensors will also detect the fault and reduce the number of locations with the correct fault duty down to one location, the one beyond the line sensor which detected the fault condition.

4. Organization of Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section B – Evaluation of the Need for the Smart Grid Distribution Pilot Projects
- Section C – Line Sensor Project
- Section D – Voltage and Reactive Power (Volt/Var) Optimization System Project (VVO)
- Section E – Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project
- Section F – Information Technology (IT) Support Activities for Smart Grid Distribution Pilot Projects
- Section G – Detailed Project Costs (Distribution and IT)
- Section H – Conclusion

B. Evaluation of the Need for the Smart Grid Distribution Pilot Projects

PG&E's strategic Smart Grid priorities for its Transmission and Distribution (T&D) system are to improve safety and reliability, reduce costs for customers, improve the efficiency of the utility infrastructure and integrate higher levels of renewables including distributed renewable resources into utility operations through the use of advanced system control, telecommunications and monitoring equipment. PG&E has identified the following two operational "barriers" and "problems" that significantly hinder its ability to achieve these priorities.

First, PG&E's ability to rapidly and accurately detect, analyze and respond to distribution system outages is hindered by its inability to precisely and quickly detect the location of specific faults using existing systems. PG&E's systems, even when augmented with SmartMeters™ outage data, identify fairly large areas that should be patrolled to find the location of the fault rather than providing a smaller area and/or definitive location.

Second, PG&E, like other electric utilities, must size and manage its distribution infrastructure in order to account for voltage variations and line losses, and uses complex line loss and voltage variation calculations to do so. This is because of the lack of more accurate voltage data from the field, particularly between the substation and individual customer meters.

In order to address these problems and reduce these barriers, PG&E has evaluated and selected the three Smart Grid Distribution Pilot projects described earlier to test, pilot and demonstrate the feasibility, scalability, costs and benefits of using sensors, and communications and control system technologies to provide distribution operators and engineers with more accurate, more rapid and more precise data from the field on line faults, voltage and other localized grid conditions. Control systems, analysis tools and the proposed project equipment deployed systematically throughout the T&D system may provide real time or near-real time, accurate information to operators, thereby enabling faster outage response and reduced outage management costs. Further, these projects will help reduce the environmental impacts of electric system operation by improving the efficiency of the electric system through reduced customer energy usage—lower voltage can reduce appliance energy usage—and reduced energy losses in the utility distribution system by optimizing voltage regulation. Volt/Var Optimization in a large scale deployment can also assist in emergency peak demand situations by reducing system or localized area demand temporarily by reducing system voltage. Lastly, the VVO control system may be able to mitigate some of the potentially adverse impacts of high penetrations of distributed solar PV generation, thereby increasing the grid's capacity for distributed solar PV and supporting California energy policy goals reliably and more cost effectively.

Using the criteria for choosing Smart Grid projects described in PG&E's Smart Grid Deployment Plan, PG&E has determined that these three pilot projects support the pursuit of Smart Grid technologies with the highest potential for improving safety and reliability, reducing Operations and Maintenance (O&M) costs, enhancing customer satisfaction and reducing environmental impacts on PG&E distribution system. However, these technologies require further evaluation and testing to confirm the potential benefits and the cost to implement, prior to making the larger investments necessary for large-scale deployment.

Each of these proposed projects is described in more detail below. In addition, IT support and pre-deployment design activities supporting all three projects are described in a separate section following the project-specific descriptions.

C. Smart Grid Line Sensor Project

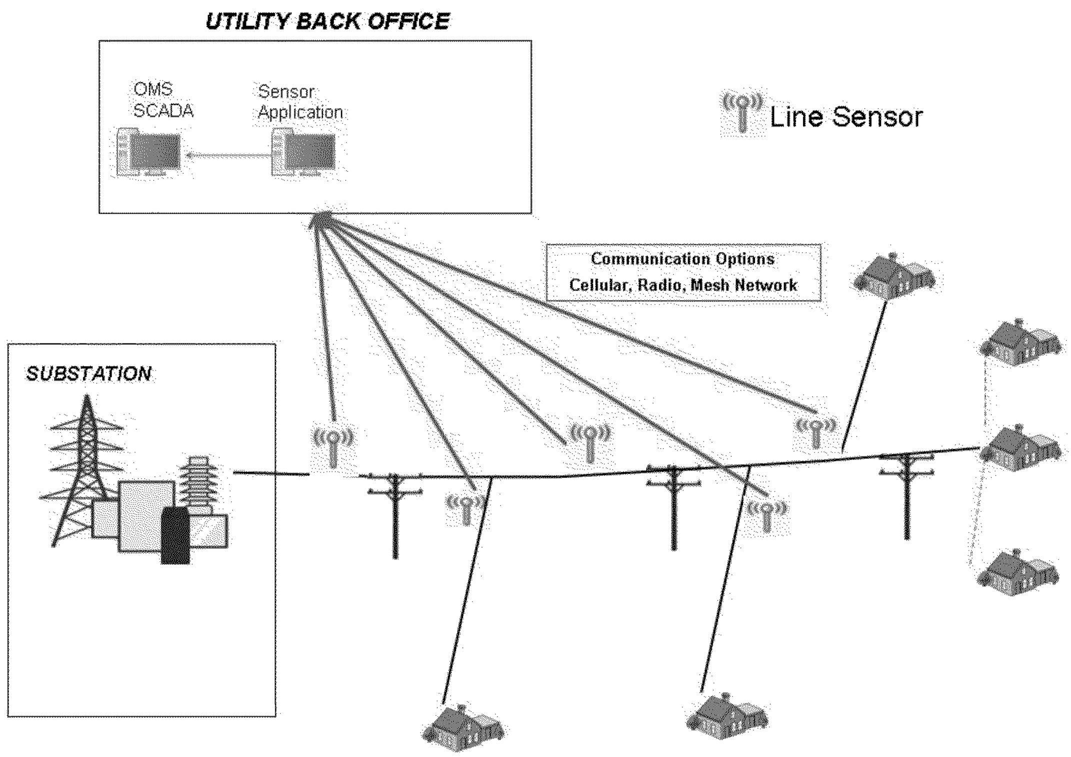
1. Project Goal and Scope

The goal of this project is to install line sensors to evaluate their impact on: (1) providing more accurate information about the fault location area, allowing faster outage restoration by reducing outage response time, and improve customer satisfaction; (2) providing accurate current flow information to operators and engineers to plan and reconfigure the system without overloading equipment based on actual current measurements instead of models; and (3) providing more accurate current flow information to engineers to support better planning of the distribution system rather than relying on models. Line sensors will be installed on the overhead and underground distribution primary system to test the capabilities of the sensors to communicate when a fault was detected, and to communicate current flow data to operators and operations and planning engineers on an as-needed or pre-determined time schedule.

2. How the Smart Grid Line Sensor Project Will Work

Line sensors are proposed to be installed on primary distribution lines at key distribution circuit locations (mainline, mainline branches, tap lines, etc.). See Figure 2-1 following:

FIGURE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
LINE SENSOR COMPONENT DIAGRAM



Line sensors can provide normal current loading per phase or at predefined levels of fault current communicate which phase detected a fault. When a line sensor detects a fault, it will communicate the detected fault information through a telecommunications system back to a central software application. The central software application will provide information to distribution operations personnel to assist in directing outage first responders to the detected fault area.

Additionally, as required by PG&E's operations and or planning engineers, the distribution line sensors provide current flow information at user defined time schedules. Operators and engineers would then use this information as part of normal daily operations and planning for future distribution system upgrades.

The distribution line sensors must be upgradeable and configurable via the telecommunications network to avoid physical field visits and the associated operating costs.

3. Line Sensor Infrastructure Technology

To effectively implement and test distribution line sensors for utility and customer benefits, the distribution line sensors will be installed at key primary distribution line locations, and managed by a central software application that:

(1) Controls the distribution line sensor configuration and communicates with other internal utility systems.

(2) Utilizes a telecommunications system that can communicate the user requested information from the distribution line sensor to the central application and *ad hoc* user information requests within specified time schedules.

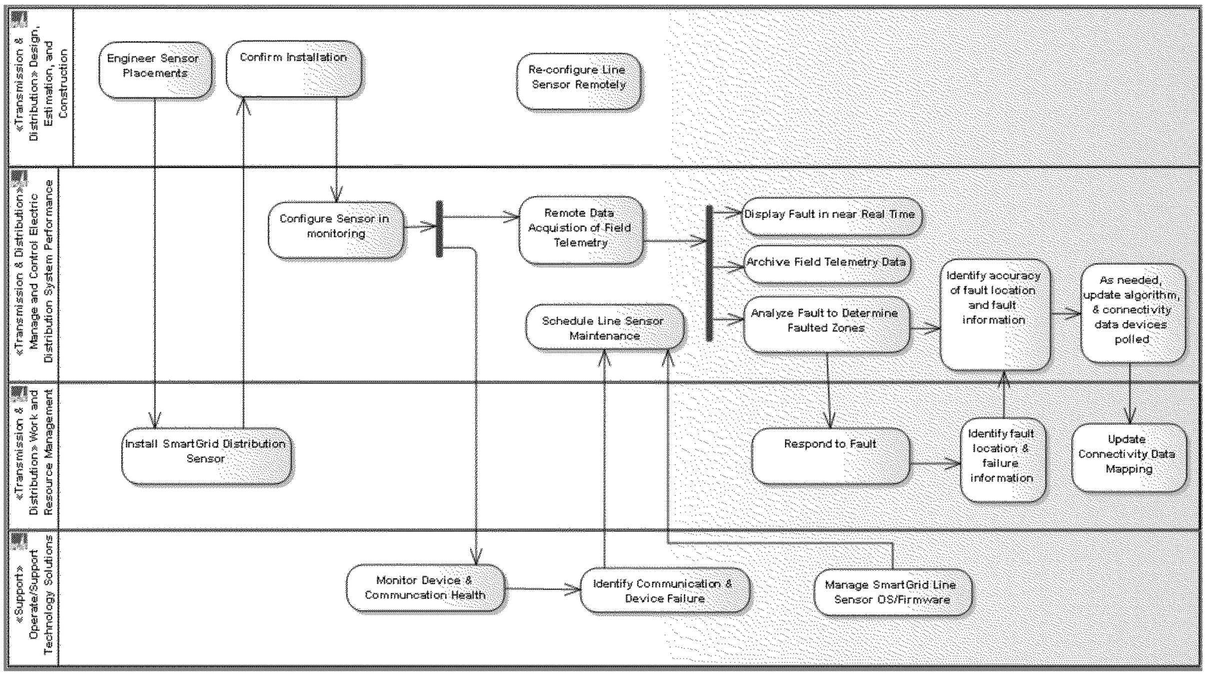
(3) Includes cyber security systems and controls that prevent intrusion and inappropriate control system changes.

(4) Complies with applicable standards.

(5) Integrates into the existing and planned future utility operating systems and technology architectures.

An initial, proposed process flow diagram for the Smart Grid Line Sensor Project is provided in the Figure 2-2 following:

FIGURE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
LINE SENSOR PROCESS



The controlling software application and distribution line sensors are highly specialized, computerized controlling system and devices when compared to the other items in this Smart Grid project. The controlling application needs to manage the distribution line sensor firmware, manage the line sensor health and provide the ability for users to define information requirements and capabilities. The distribution line sensors need to be upgradeable remotely via the telecommunications network from the central application, have the ability for the user to define information requirements and have the capabilities to use one or many multiple telecommunication systems across PG&E's service area (i.e., cellular, mesh radio network, satellite communications, etc.) as needed.

Five other key pilot project technology elements, applications, information architecture, telecommunications, cyber security, and standards and testing, will be provided by IT systems that are common across or otherwise support all three of the proposed T&D projects. These supporting IT activities are discussed in Section F of this chapter.

4. Project Activities

During the start-up phase of the project, PG&E will select a number of different line sensor products to test and pilot on PG&E's distribution system. PG&E will scan the equipment industry for line sensors that are in production and or being used by other utilities; benchmark other utilities using line sensors to understand their potential benefits, costs and usage in operations and planning; review applicable standards and identify which specific line sensors comply with these standards. Examples of applicable standards include Federal Communications Commission (FCC) standards for radio operations, National Institute of Standards and Technology Internal Report (NISTIR) security, Institute of Electrical and Electronic Engineers (IEEE), and other industry, state, federal and PG&E standards.

PG&E will then analyze the technology requirements to support line sensors, including applications; cyber security; information architecture; standards and lab testing; and telecommunications.

Once this analysis is complete, PG&E will plan and complete the testing of the technologies for use in the test phase. In a laboratory environment, PG&E will test the selected line sensors and identify the line sensors to use for the field pilot. This will include testing the line sensor project systems and devices against standards, prototyping line sensor integration and technologies, installing and testing the communications systems to be integrated with the sensors, and testing-related software applications. More specifically, PG&E's test program for the project will:

(a) Install and test line sensors and simulate faults and line currents in a controlled lab environment to understand the systems capabilities and performance.

(b) Integrate line sensor fault information into PG&E's SCADA and Outage Management System.

(c) Test remote firmware upgrades to line sensors and controllable sensor settings.

(d) Integrate line sensor current loading information into PG&E's load tracking and analysis system.

(e) Develop documentation and training materials to support the workforce installing, operating and utilizing the line sensor information during the pilot deployment.

Upon completion of the lab test phase, PG&E will then deploy recommended line sensor products on up to 30 distribution feeders in three of PG&E's divisions and proceed to operate, evaluate and demonstrate the project in the field. The results of the testing in the field, including performance metrics and any iterative changes in the configuration and design of the deployment, will be formally evaluated and reported to PG&E management including recommendations on whether to proceed or not proceed with further deployment. PG&E will provide status reports on this and the other Smart Grid projects to the Commission as part of its annual Smart Grid progress reporting required by Senate Bill (SB) 17.

5. Project Benefits

PG&E expects that the Smart Grid Line Sensor project will provide the following benefits and potential improvements to PG&E's distribution system following large scale deployment:

- Improved systemwide and regional reliability, as measured by System Average Interruption Duration Index and Customer Average Interruption Duration Index, by identifying and resolving outage locations and recurring outages better than current tools.
- Improved customer satisfaction with electric system reliability.
- Improved employee and public safety by providing outage and area impacted information faster.
- Avoided O&M costs by faster location and isolation of damaged equipment and avoided labor and transportation costs for personnel responding to outages.

Line sensor technology is maturing rapidly with multiple vendors communicating product availability and benefits. However, since the products are still new, PG&E needs to evaluate vendor claims and quantify actual benefits. PG&E believes that a proven line sensor product will enhance other distribution automation projects, (i.e., detection and location of outages and high impedance faults, etc.) because it can be scaled, deployed and integrated easily once a base IT and telecommunications infrastructure is in place.

6. Project Costs

Smart Grid Line Sensor Project Pilot Costs are outlined in Table 2-2 following:

TABLE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
LINE SENSOR PROJECT PILOT COSTS
($ IN THOUSANDS)

Line No.		2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	Grand Total
1	Line Sensor					
2	Capital	$2,551	$8,483	$2,382	$1,931	$15,347
3	Expense	–	199	641	721	1,561
4	Total	$2,551	$8,682	$3,023	$2,652	$16,908

D. Voltage and Reactive Power (Volt/Var) Optimization Project (VVO)

1. Project Goal and Scope

The goal of this project is to pilot a VVO Optimization system to evaluate its ability to reduce customer energy usage and reduce utility system losses by managing the distribution voltage from the substation to the customer's service point (distribution primary, secondary and service systems). The project also includes feeders with high penetrations of renewables which can adversely impact the feeder voltage profile. PG&E will pilot a VVO system that will communicate via the existing SCADA system to distribution line devices that will control the voltage on the distribution feeder. Distribution line devices managed by the VVO system that control voltage are the substation transformer load tap changer, distribution line regulators, and distribution line capacitor banks. Additionally, the project will enable voltage inputs to the VVO controlling system by enabling SmartMeters™ to provide voltage measurements along with the distribution line voltage controlling devices. Currently, SmartMeters™ can display the voltage on the meter but require a firmware upgrade to enable transmitting the voltage measurements back to the proposed central VVO system. Additionally, an application to manage the SmartMeter™ voltage user requirements is available but not installed as part of PG&E's approved SmartMeter™ project.

2. How Would the VVO Optimization System Project Work

A VVO software control system will be installed to manage voltage and var regulation devices on individual radial primary distribution circuits. The VVO system would utilize the voltage measurement information from select or bellwether SmartMeters™ to understand the high and low voltages within each voltage zone in order to perform the necessary calculations to control the voltage and Var regulation devices to lower or raise the voltage on the distribution feeder to the lowest possible voltage while maintaining the required power factor at the distribution substation feeder level.

The SmartMeter™ voltage measurements would be communicated from the SmartMeter™ through PG&E's mesh radio network—SmartMeter™ to relay, relay to access point, access point to central operational data storage. The central operational data storage location is then linked with the VVO computerized control system to provide the necessary high- and low-voltage information for the individual distribution feeders. An existing central SmartMeter™ voltage management tool would be used to manage how often the SmartMeter™ voltage information is required and which SmartMeters™ will be polled for the data. Basically, the tool will "ping" SmartMeters™ on a user defined timeframe and only ask for SmartMeter™ voltages that are outside defined voltage limits as defined in Rule 2 (i.e., 114-126 volts).[2]

The distribution line and substation voltage and power factor information will be communicated by PG&E's existing SCADA system to an operational data storage system that is linked with the VVO computerized control software. This same SCADA system is used to execute commands sent to voltage and var regulating devices to perform the requested control changes. The SCADA system communicates over the existing PG&E radio network which links the VVO system to the devices it is controlling.

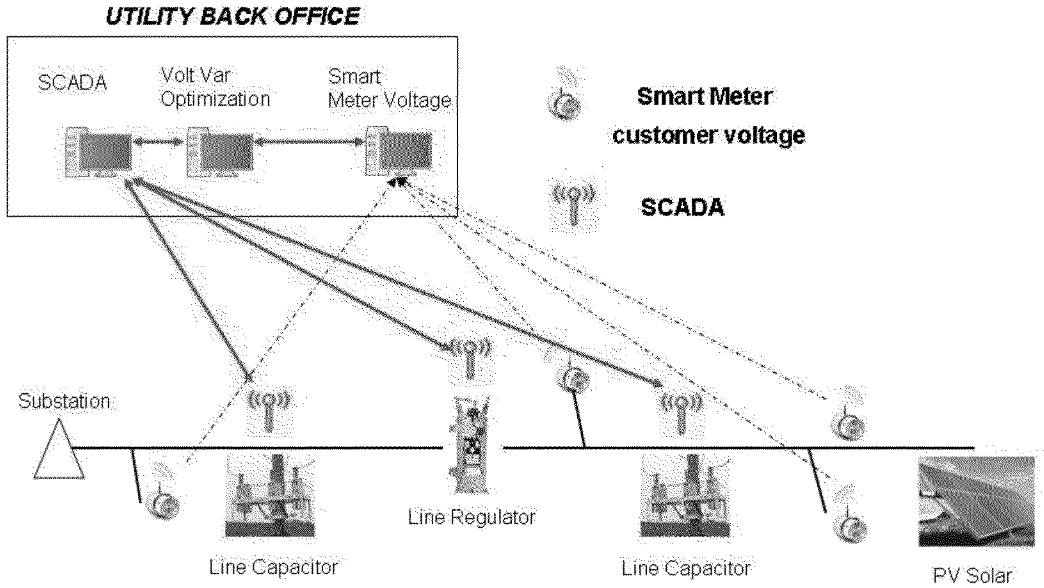
---

[2] CPUC Rule 2 defines what voltage ranges investor-owned utilities in California must maintain on their distribution systems.

The VVO system simultaneously manages voltage and the distribution system power factor[3] at the distribution feeder level. Careful power factor management can minimize electrical losses in the distribution system. Distribution operators will maintain manual override control capability over each individual circuit VVO control system.

A component diagram for the VVO Project is provided in the Figure 2-3 following:

FIGURE 2-3
PACIFIC GAS AND ELECTRIC COMPANY
VVO COMPONENT DIAGRAM



The voltage and Var regulating devices will receive the command, perform the operation and communicate back to the VVO controlling system what operation it performed. PG&E, as part of the analyze and test phases, will engineer the number of operations that each voltage and var regulating device can perform daily, monthly and yearly to provide a reliable and safe system that does not deteriorate equipment creating increased future equipment failures or increased equipment maintenance costs. The desired

[3] Powerfactor is calculated by dividing a unit of watt by a unit of var (e.g., Powerfactor = cos [$\tan^{-1}$ (0 var / 1 watt)] = 1.0 powerfactor). A powerfactor of 1.0 minimizes line losses to the lowest point possible assuming voltage is at its lowest value per CPUC Rule 2.

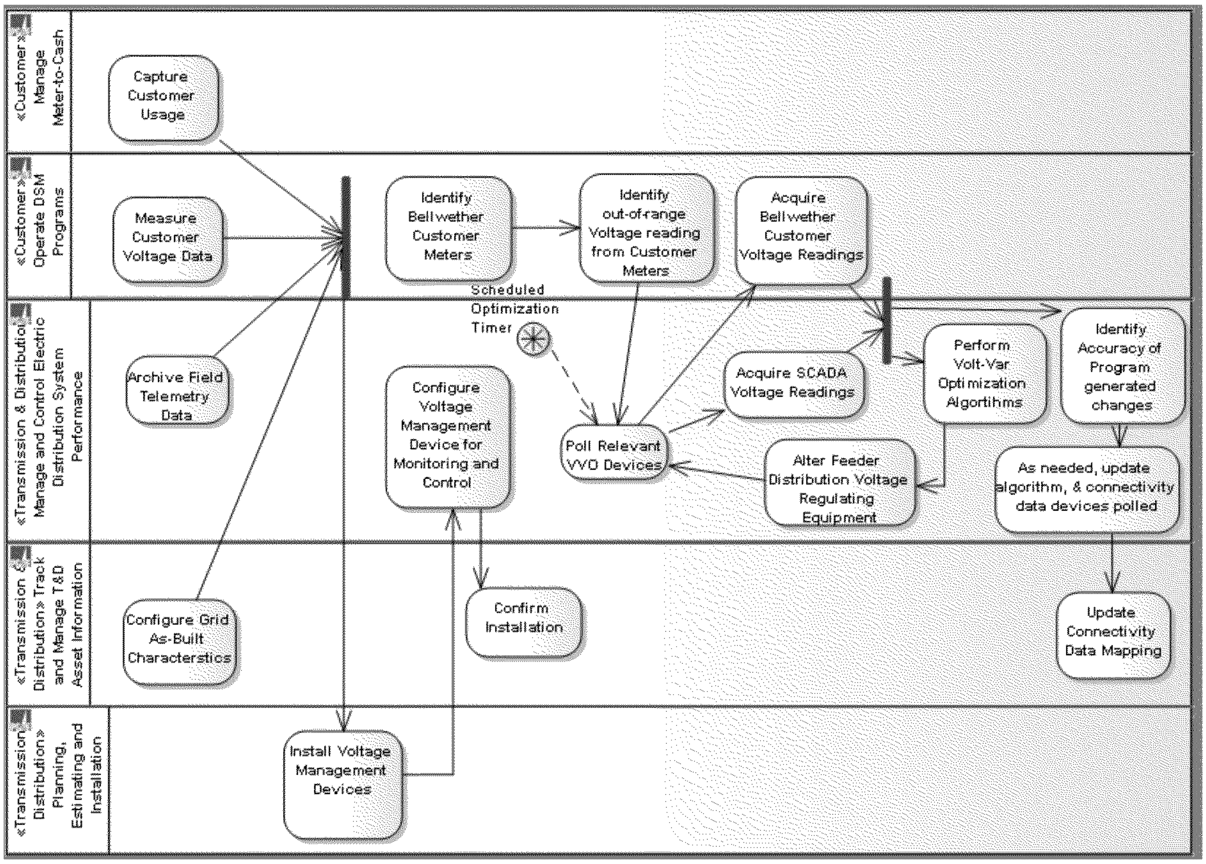
operational parameters for the voltage and var management equipment are well known in the industry and have been tested over the many years of operation under actual field conditions. Additionally, the equipment vendors recommend the number of operations for each voltage and var regulating device between maintenance intervals.

3. VVO Computerized Controlling Infrastructure Technology

The application called the VVO computerized control system is the key system that is required to manage the distribution feeder voltage and power factor. It relies on the voltage and power factor information obtained from select or bellwether SmartMeters™, the voltage and var regulating devices and the feeder breaker relay. This data requirement mimics existing SCADA information currently provided by limited amounts of distribution substation equipment and line voltage and var regulating devices. Approximately half of all distribution substation equipment and very few line voltage and var regulating devices can provide voltage and power factor information today. The VVO application automatically controls a system that has historically been manually set to operate within the desired ranges at peak load and minimum load but sub-optimally the rest of the time because the technology has not been readily available.

The VVO system manages the distribution line device configuration and communicates with other internal utility systems, utilizes multiple telecommunication systems to retrieve voltage and power factor information and controls voltage and Var regulating equipment using SCADA system equipment, includes cyber security systems and controls to prevent intrusion and inappropriate control system changes, complies with applicable standards and is integrated into the existing and planned utility operating systems and architectures. An initial process flow diagram for the VVO Project is provided in Figure 2-4 following:

FIGURE 2-4
PACIFIC GAS AND ELECTRIC COMPANY
VVO PROCESS



The VVO control application is a highly specialized, computerized system when compared to the other items proposed in this Smart Grid project. The control application needs to manage the substation and distribution line voltage and Var regulating equipment, manage the line equipment health and provide the ability for users to define information requirements and capabilities. The distribution line voltage and Var regulating devices need to have the ability to use one or many multiple communication systems across PG&E's service area (i.e., cellular, mesh radio network, radio, satellite communications, etc.).

The five IT elements required to support the VVO Project: applications, information architecture, telecommunications, cyber security, and standards and testing, discussed in Section F of this chapter.

4. Project Activities

In the initial phase of the project, PG&E will scan the industry for VVO systems that are in production and or being used by other utilities. PG&E will benchmark other utilities using VVO systems to understand their benefits, costs and usage in operations and planning. PG&E also will review applicable standards and which VVO systems are complying with these standards. The applicable standards include FCC standards for radio operations, security guidance from National Institute of Standards and Technology (NIST), Department of Homeland Security, North American Electric Reliability Corporation, International Electro-Technical Commission, Advanced Security Acceleration Project (ASAP),IEEE, and other industry, state, federal and PG&E standards.

PG&E then will analyze the technology requirements to support VVO system. This includes turning on the already-installed voltage measuring capability of its SmartMeter™ system at the meter and understanding the voltage software system and its capabilities.

After completing this analysis, PG&E will begin lab testing of VVO systems and devices against standards and for compliance with agreed-upon specifications to ensure compliance, including testing associated software applications. This lab testing will include the simulation of operations to understand the VVO system capabilities and performance against Rule 2 voltage requirements, as well as the ability to integrate into PG&E's SCADA system. Likewise, PG&E will test the ability to integrate its SmartMeter™ and line device voltage data into the VVO system. At this point, PG&E also will scope the training needs of the workforce utilizing and operating the VVO system and develop training to support the pilot.

After completion of the test phase, PG&E will install the VVO and telecommunications system on up to 12 distribution feeders in three of PG&E's divisions. All the systems included and integrated in the pilot phase will be integrated into the utility production systems (telecommunications, SCADA, etc.). The results of the field pilot, including any iteration on design and scope of activities, will be formally evaluated and reported to PG&E management including recommendations on whether to proceed or not proceed with further deployment. PG&E will provide status reports on this and other projects to the Commission as part of it annual Smart Grid progress reporting required by SB 17.

5. Project Benefits

PG&E expects that the VVO Pilot Project can demonstrate the potential to deliver energy cost savings to customers and reduced utility system losses that reduce energy procurement costs for customers. In addition, PG&E expects that the Project can demonstrate the ability of PG&E's current distribution system to reliably and cost-effectively integrate and manage the variations in voltage associated with intermittent distributed generation, especially solar PV generation.

Current industry estimates are that reducing distribution voltage by 1 percent provides a 0.5 to 0.8 percent reduction in demand from customer appliance and on the utility distribution system. The customer energy usage and costs would be reduced by lowering voltage at the customer meter to the lowest voltage while staying within the limits of Rule 2. There is a direct relationship between energy consumption by an appliance and the voltage at that appliance. This concept of managing energy consumption through voltage control is known as conservation voltage regulation. Conservation voltage regulation is not new to the utility industry but technologies are now available to make larger-scale implementation much more feasible and cost effective. As a result, demand and energy and the corresponding energy procurement costs would be reduced avoiding costs that would otherwise be passed on to customers. Just as importantly, distributed renewable generation penetration can likely be reliably increased by using the VVO system to maintain the distribution primary voltage within desired operating ranges. The VVO system would manage and reduce the potential for high-voltage impacting operation of the customer PV equipment operations.

6. Project Costs

The VVO Project Pilot Costs are outlined in Table 2-3 following:

TABLE 2-3
PACIFIC GAS AND ELECTRIC COMPANY
VVO PILOT COSTS
($ IN THOUSANDS)

Line No.		2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	Grand Total
1	VVO – Volt Var Optimization					
2	Capital	$3,856	$14,645	$9,356	$8,735	$36,592
3	Expense	–	298	925	1,012	2,236
4	Total	$3,856	$14,943	$10,281	$9,747	$38,828

E. Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project

1. Project Goal and Scope

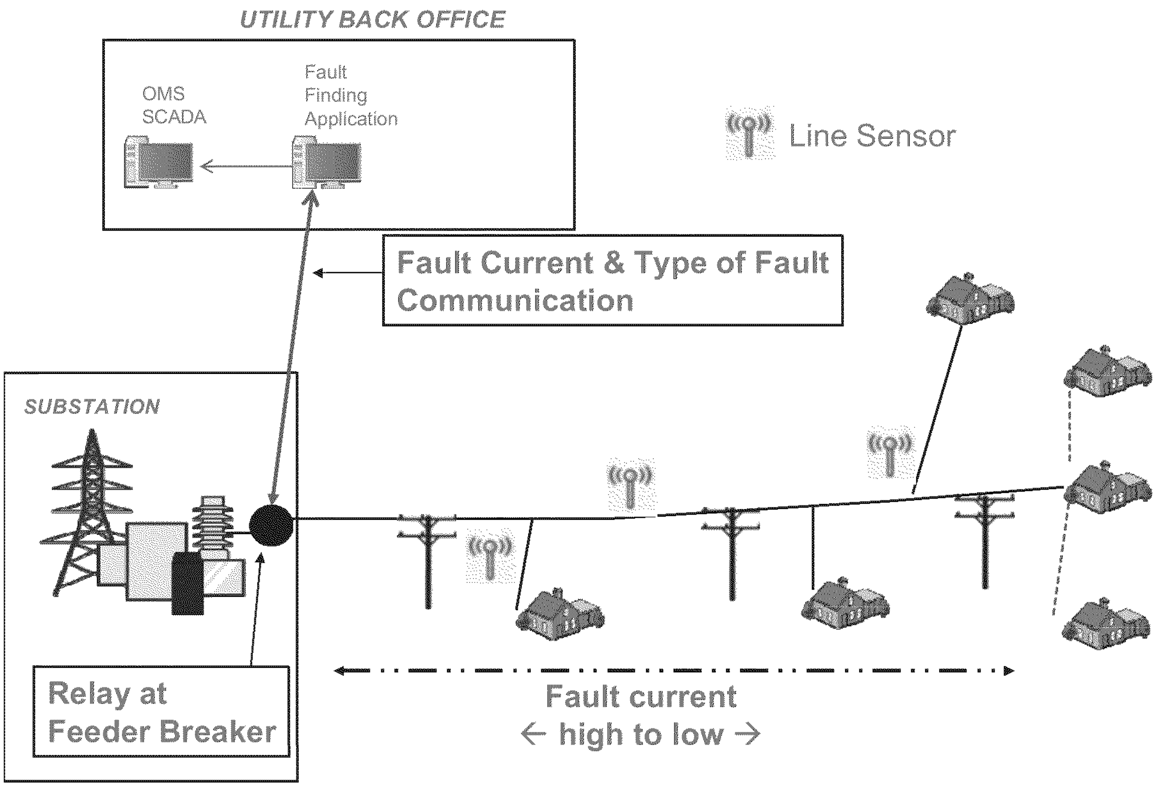
The goal of this project is to install and evaluate a fault-finding software system or systems that will assist in more precisely locating failed equipment that caused an outage and determine if there are additional benefits of providing a more accurate location to utility first responders to outages.

2. How the Detect and Locate Outages Project Will Work

PG&E will install fault-finding software in the utility's control system network to provide distribution operators responsible for the individual radial distribution feeders with the ability for to see the results and recommended actions. The fault-finding software utilizes available fault duty information from protection studies and actual field fault duty inputs from distribution circuit relays quantifying the magnitude of fault current and type of the fault to provide the likely locations of the faulted equipment. PG&E expects to incorporate other devices to assist in narrowing the physical location of the fault such as line sensors described earlier in this chapter. For example, if there were three locations with the same fault duty characteristics identified by the fault-finding software, having a set of line sensors in the path between these locations and the feeder relay will allow the line sensor to provide one location with the fault characteristic to investigate. Additionally, PG&E would look to incorporate systems and devices (including SmartMeters™) to locate high impedance faults and capture waveform characteristics to assist in detecting and finding these hazardous conditions.

These additional devices may be used by PG&E engineers to assist in locating recurring temporary outages that cannot be detected through other means. The components of the fault-finding technology to be used in the Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project are described in Figure 2-5 following:

FIGURE 2-5
PACIFIC GAS AND ELECTRIC COMPANY
DETECT AND LOCATE DISTRIBUTION LINE OUTAGES AND FAULTED CIRCUIT CONDITIONS PROJECT COMPONENTS

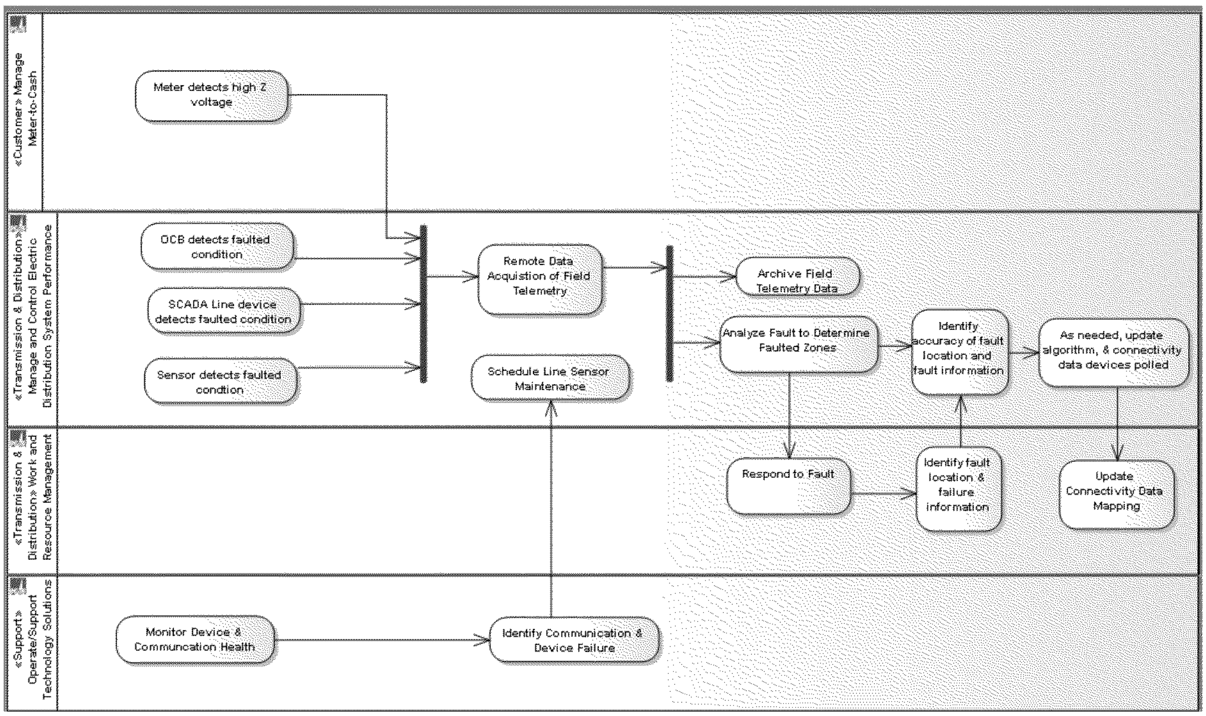


3. Fault-Finding Infrastructure Technology

The centralized fault-finding software application is the key system that is required to integrate existing protection fault duty studies with actual fault duty information from the distribution feeder relay to provide the likely faulted location on a radial distribution feeder.

The fault-finding system will utilize PG&E's multiple telecommunication systems to retrieve the distribution feeder relay fault information. It will not control any distribution substation or line devices and is intended to only communicate recommendations to distribution operators and outage first responders on the likely location of the faulted equipment. The fault-finding software will include a cyber security system that can prevent intrusion and inappropriate system changes, complies with applicable standards and is integrated into the existing and planned utility operating systems and architectures. The process flow diagram for the Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project is provided in the Figure 2-6 following:

FIGURE 2-6
PACIFIC GAS AND ELECTRIC COMPANY
DETECT AND LOCATE DISTRIBUTION LINE OUTAGES AND FAULTED CIRCUIT CONDITIONS PROJECT PROCESS



The five IT elements to support the Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project: applications, information technology, telecommunications, cyber security, and standards and testing, and communications are discussed in Section F of this chapter.

4. Project Activities

As with the other projects described in this chapter, during the initial phase, PG&E will scan the equipment industry for fault detection software systems that are in production and or being used by other utilities. PG&E

will benchmark other utilities using fault detection systems and substation relays to understand their benefits, costs and usage in operations and planning. PG&E will review approved standards and what fault-finding systems are adhering to approved standards. The applicable standards include FCC standards for radio operations, NISTIR security, IEEE, and other industry, state, federal and PG&E standards. Also like the other projects, PG&E will analyze the technology requirements to support fault-finding systems and software.

During the lab test phase of the project, PG&E will test the software, systems and related devices against standards defined above and specifications to ensure compliance. Utility industry standard relays that provide fault duty will be used and tested. A fault-finding system will be installed in the lab to simulate operations to understand the systems and software capabilities and performance. The fault-finding system also will be integrated into PG&E's SCADA and possibly PG&E's Outage Management System and tested in the lab. Training needs of the workforce utilizing and operating the fault-finding system will be evaluated and training programs developed.

During the field pilot phase, PG&E will install fault-finding software systems and telecommunications system on up to 15 distribution feeders in two of PG&E's divisions. All the systems and software in the test phase will be integrated into the utility production system during the field pilot phase (telecommunications, software, security, etc.). After appropriate field testing, including any iteration in design and deployment activities, PG&E will formally evaluate the results and make recommendations to PG&E management including recommendations on whether to proceed or not proceed with further deployment. PG&E will provide status reports on this and other projects to the Commission as part of it annual Smart Grid progress reporting required by SB 17.

5. Project Benefits

PG&E expects that the project will have similar but additional benefits to the Line Sensor project, including the demonstration of technologies to improve system safety and reliability, reduce outage detection and management costs, and improve customer satisfaction. This system can provide multiple fault locations on each circuit based upon the fault characteristics that the substation relay provides and the fault locating software uses to project the faulted location. The Line Sensors will assist in pinpointing which of the fault locations is the correct one when multiple locations are projected by the fault locating software.

6. Project Costs

The Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project Pilot Costs are outlined in Table 2-4 following:

TABLE 2-4
PACIFIC GAS AND ELECTRIC COMPANY
DETECT AND LOCATE DISTRIBUTION LINE OUTAGES AND FAULTED CIRCUIT CONDITIONS PROJECT PILOT COSTS
($ IN THOUSANDS)

Line No.		2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	Grand Total
1	Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project					
2	Capital	$1,733	$8,119	$1,294	$1,239	$12,384
3	Expense	–	105	253	267	625
4	Total	$1,733	$8,224	$1,547	$1,506	$13,009

F. IT Support Activities for Smart Grid Distribution Pilot Projects

As discussed above in the individual project descriptions, IT support is required for each project to analyze, architect, install, test, approve and implement systems that securely integrate data, information, distribution line device control, and controlling software systems. The IT support activities are categorized in the following technology domain areas:

(a) Applications

(b) Information Architecture

(c) Telecommunications

(d) Cyber Security

(e) Standards and Laboratory Testing

In order to scope the required IT support activities for the projects, PG&E developed a full-scale, high-level conceptual architecture for each project. The conceptual architecture includes three different views of each project to ensure a comprehensive view into the business requirements for the projects. These architecture views are: (1) a business process flow view; (2) a business/IT informational view; and (3) an IT applications view. The supporting IT work activities were then scoped and estimated in alignment with the business requirements to arrive at a suggested scope of work and costs for the necessary IT support activities for the projects.

In addition, over the course of each pilot project analysis, evaluation and initial design of commercial scale IT activities required to support full-scale, production-level system deployment will be conducted based on the design and results of the pilots. This approach is a pragmatic approach to ensure foundational IT infrastructure for potential system deployment is evaluated and scaled at the appropriate size and rate before a decision is made on full deployment.

The following section describes the IT activities in each of the five technology domains required to support the implementation of the three Smart Grid Distribution Pilot projects in this chapter.

1. Applications

Applications are the central "brain" for Smart Grid systems. The systems can be comprised of one or more applications and essentially provide the ability to automate existing manually controlled operations. These applications are keys to the increased automation needed to derive benefits from the proposed Smart Grid projects. The increase in the number of telemetry data points and the need to process complex events with speed and precision require new applications to perform those operations within the context of the proposed systems in this filing. While there may be other supporting applications that comprise the entirety of the Smart Grid system, the applications referred to in this particular section are those that specifically perform the targeted business function. Generally speaking, the applications will collect data through a variety of source systems at pre-determined intervals, process that data to inform another system or user, and provide output through either reporting, data feeds to other systems, terminal display, and specific control activities in the case of new field device operations. For the proposed system control actions, control signals are transmitted to distribution system devices to take action and these devices report back on the action taken. The system design, which is based on the business requirements, can vary depending on the type of applications needed for a given system. The application, for example, may be installed centrally where it controls multiple circuits and devices at once or it can be de-centralized and operate at key equipment field locations controlling fewer circuits or devices by specific area. There are various tradeoffs to each design element which are analyzed as part of the overall IT efforts for each project to come up with detailed system design blueprints. The blueprints will depict the applications for each project in the context of their system definition and the various system interfaces associated with collecting data, processing it, and acting on it. While a detailed design does not yet exist for the three projects, each was modeled at a conceptual design level depicting requirements for new applications and augmentations or integrations to existing applications. Those applications are detailed below.

<u>Smart Grid Line Sensor Applications</u>

At a high-level, the Smart Grid Line Sensor project system will send fault indication and current flow data to a central collection point where the data will be processed and analyzed by the application and the operators for operational use then sent to a data repository for storage and potential further analysis. For the Line Sensor project, there are three new applications proposed and integration requirements for two existing applications.

First is the Sensor Head-End application. The sensor head-end manages device configuration and direct communication to each device. The sensor head-end could take many forms from a SCADA application to other technologies.

Second is the Field Area Network Head-End application. The field area network provides communication from line sensor devices in the field to the PG&E network. The application is the interface gateway for consolidating sensor data from the field.

The third is the Fault Location Module application. The fault location module will incorporate the line sensor fault indications (data) collected from the Field Area Network Head-End application into the inference algorithms to allow for the identification of the faulted zone (i.e., between two line sensors) for an outage.

The next two applications are existing applications that will be leveraged as part of the overall Smart Grid Line Sensor project system. The Data Historian application will provide a repository for storage, access and analysis of load information provided by line sensors. The Geographic Information System (GIS)/Asset Management application will provide asset and connectivity information to the fault location module and other applications in the solution (e.g., Data Historian and Sensor Head-End).

<u>VVO Applications</u>

For the VVO system, the VVO controlling application will get voltage information from SmartMeters™, voltage information from line devices (switches, reclosers, voltage regulators, load tap changer, capacitor banks), and power factor information from the feeder breaker and then make a decision on what changes are required on the line devices (for example reduce or increase voltage on the load tap changer and or line regulator), and electronically transmit the necessary instructions to those devices. For VVO, there are two new applications proposed and integration requirements for three existing applications.

First is the SmartMeter™ Voltage Monitoring Application/Firmware. The PG&E SmartMeter™ system, will require a new application and updated meter/network firmware to enable voltage monitoring on the system.

Second is the VVO Engine application. This application will accept triggers and inputs from the SmartMeter™ system and field telemetry via SCADA. The inputs will allow it to optimize grid operation based on configured business rules and priorities set by PG&E.

The next three applications are existing applications that will be leveraged as part of the overall Smart Grid VVO system. First is the SCADA system. The SCADA system will provide telemetry and control to substation and field devices on the electric system. Second is the Data Historian. The Data Historian will provide a repository for storage, access and analysis of load triggers, inputs, outputs and results of the VVO engine. Third is the GIS/Asset Management System. This system will provide asset and connectivity information to the VVO engine and other applications in the solution (e.g., Data Historian and Advanced Metering Infrastructure Voltage Monitoring Application).

Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project Applications

This computer system allows for inputs from multiple data sources to process and calculate various business scenarios related to faults such as location. For this computer system, there are likely two new applications and a third with integration requirements.

The first is the Fault Location Application which compares the fault-duty calculations from a protection analysis to the actual fault-duty and fault-type provided by the substation based feeder relay which then indicates the possible fault locations. It can incorporate other data from line sensors and customer calls to determine the correct locations when multiple fault locations could result.

The second is the Fault Database which will provide functionality for retrieval, storage, and access of fault data and signatures from relays. This function can be provided by the Data Historian or a custom-built solution, among other options.

The third is the GIS/Asset Management system which will provide asset and connectivity information to the Distribution Management System-Based fault location module.

2. Information Architecture

Because of the increased quantity of information exchanges represented by the introduction of new devices and more widespread voltage telemetry, there is a corresponding increase in the complexity of the interactions between the systems referred to in the previous applications section. The complex system interactions provide an opportunity to simplify with technologies that first aggregate data from systems into one place rather than directly linking systems point-to-point. This approach allows for monitoring and management of the movement of information between the systems to ensure improved operational quality and stability. These technologies, for example, will be deployed between systems such as that between customer SmartMeters™ and the VVO platform. Because of these new information-centric requirements, a systematic analysis of the newly introduced telemetry and control data is necessary to ensure that it is properly structured for ease of use and system consumption throughout PG&E's application infrastructure. This will help maximize the investment of the implementation of these pilot technologies, and will help facilitate a more cost-effective, and accurate, evaluation of the implications of any full deployment of the new sensors, voltage management algorithms, and fault detection applications. In each case, the full benefit of the investment in this pilot can only be realized if the information introduced by the new "Smart" telemetry and capabilities in this filing are well understood and constructed for an eventual, orderly, introduction into the broader field and technology operations for PG&E.

Given the context above, the distribution pilots in this filing all require a reliable and interconnected information exchange among the platforms, devices and applications at play to ensure the overall data reliability, integrity and confidentiality required to execute a successful pilot. In order to ensure that connectivity, IT Information architecture enhancements are required for each project. These have been derived based on the proposed pilot scope deployment for each project, the requirements for application integration in support of each pilot, and the associated data exchange needs. The data exchange needs are characterized by:

(1) The volume of the data exchanged
(2) The frequency of the data exchanged
(3) The volatility of the data (how often it changes)
(4) Reporting needs for the new information

For each such information exchange or data store, the scope of effort that has been considered in the estimations involves:

(1) Performing a thorough analysis of the data exchange or information storage needs based upon the results of the deployment pilot evaluations of the various candidate products.
(2) Developing information structures and architectures to support the movement and reporting of identified information based upon the identified data in full deployment.
(3) Identifying the systems software and hardware required to support the movement of data in the full deployment.

(4) Implementing limited deployments of software and hardware to support the deployment evaluation.

(5) Performing data correlation, validation and analysis tools to ensure operational data quality and stability.

(6) New and/or enhanced data monitoring and information management tools to provide data in a useful manner to operators and engineers to act timely on faults or other situations.

The estimates in this filing have been derived by estimating the work associated with each activity for each information exchange. In addition as part of the deployment pilots, evaluation and analysis will be conducted to determine the information architecture needs at full deployment to validate appropriate interconnectivity between systems at production scale.

3. Telecommunications

Telecommunications infrastructure enhancements are required for the pilots in order to provide a data path for information and control of new devices on the electric distribution systems. The telecommunications systems in place at PG&E for distribution line devices (switches, capacitors, etc.) utilize Radio Frequency technology that requires line-of-sight to the devices for effective operations. The SmartMeter™ system utilizes a radio frequency mesh network that relies on many devices that create a mesh network to receive and transmit customer meter data. This mesh network system is made up of relays and SmartMeters™ that act together to funnel customer meter data to a central access point that then communicates to a central storage location.

Within the Smart Grid Line Sensors and VVO projects, PG&E will be seeking to utilize either a mesh network similar to the current SmartMeter™ network, cellular networks, satellite and/or other communication systems that provide the enhanced communications capabilities needed to support the projects. Therefore, PG&E has included incremental IT activities for the installation of telecommunications system enhancements to support the distribution deployment pilots.

4. Cyber Security

As described in PG&E's Smart Grid Deployment Plan, effective cyber security controls and mechanisms are critical to the safe, reliable, and secure operation of Smart Grid technologies. The proposed Smart Grid pilots introduce new, computer-enabled devices onto the traditional electric distribution infrastructure which has not been subject to the more robust security measures currently applied to both generation facilities and the transmission network. Therefore, new devices on the electricity infrastructure will need to be evaluated and tested to ensure robust security controls are in place to mitigate cyber security threats and risks. This is especially important when new IT enabled devices are placed on the production network and new systems are created that have a closed loop control (no human intervention). The system must not introduce vulnerabilities into the safety, reliability or integrity of the electric systems operations.

PG&E has included within IT support for the projects, the activities needed to maintain a level of cyber security and address the following security risks and domain areas:

(1) Secure Design and Governance

The architectural design process that ensures security is built-in early from the beginning so that risk can be iteratively managed and mitigated throughout any project. It begins with the conceptual security model and ends with logical and physical design blueprints, along with the corresponding security plans and ongoing reviews to ensure the security lifecycle is being adhered to throughout. This also includes efforts to align industry standards to architectural efforts.

(2) Risk and Program Management and Metrics

These efforts provide risk assessment activities throughout the lifecycle of a project. These may include activities such as risk assessments, audit and compliance management, and residual risk management through established plans, etc. New security profiles for Smart Grid will also be required to be developed, aligned to industry recommendations, and refined for PG&E-specific use.

(3) Policy, Training and Awareness

These efforts seek to integrate any new change to the business that occurs for security policy including the documentation, training, and awareness to inform and change the processes required to secure the Smart Grid.

(4) Testing, Certification and Audit

These efforts provide critical security testing for new devices and systems that are being introduced into the enterprise. Activities may include penetration testing and may also involve certification work to ensure new devices are up to specifications to the company and industry standards as well configuration and state management to ensure that the systems operate and remain within their expected state.

(5) Threat and Vulnerability Management

Provides an early-warning preventative system through the use of information-sharing and correlation tools and techniques. Also establishes tools and techniques for rapidly identifying, quarantining, and removing identified system vulnerabilities through technologies such as anti-malware and automated system patching. PG&E has established a security threat management team to identify credible emerging threats and enable enhanced operational monitoring. Additional public/private partnerships have also been developed within this function to enhance information sharing.

(6) Incident Management

These services seek to quickly contain and quarantine, minimize and manage any cyber security incidents that occur. The services holistically review and extend existing incident management processes to be inclusive of the identification and consideration of cyber security risk as part of the operational incident management triage for the new Smart Grid systems.

(7) Tools and Technology Administration

These services provide the operational control for security solutions that extend across the business. Systems that manage the logging and authentication for Smart Grid devices are examples of services that are performed under this category.

Most of the security estimates are labor associated with carrying out one or more of 28 specific activities that roll up to the seven categories listed above. Each of those activities were then estimated across the analyze, test and pilot phases for each of the business initiatives. The focus of the effort is primarily on architecture, control specification, risk assessment, and operations of the limited scope pilots. It is important to note that there may be subsequent mandatory controls that arise out of risk assessment activity to take place during the initial analyze/test period and the subsequent pilot phase which cannot be fully predicted at this point for the filing. Due to the limited scope of the initiatives, it is also anticipated that compensating controls and/or manual controls will likely fill gaps where risks are noted during the assessment periods. The actual building of any supplemental security hardware and software controls for the security system will be depicted in the architectural and design deliverables at the final stages of this Smart Grid pilot project. The exceptions to this have identified five very limited areas of security hardware/software investments.

Because these are small scale production pilots (with closed-loop systems for example), a standard risk assessment process will be applied immediately up front followed by a second risk assessment in the pilot phase to determine production scalability risks to feed the production scale architectural design and control model. In addition, a detailed security profile that is a derivative aligned to the works produced by NIST[4] and the contributing organizations such as ASAP-SG[5] must be developed for each of these initiatives to perform the risk assessments in the context of the emerging regulatory frameworks. From a security perspective, part of this pilot effort is to expose and discover the risks of these systems and mitigate them before they scale to full production. This ensures an iterative approach to security that “bakes it in” so that it is not just designed and then applied retroactively.

In addition, as part of the pilot deployments, IT evaluation and analysis will be conducted to determine the security requirements at full production

[4] National Institute of Standards and Technology.

[5] Advanced Security Acceleration Project – Smart Grid.

scale. This is critical to expose and discover potential risks and mitigate them before systems are scaled to full production, and to ensure that security controls are “baked-in” to initial designs rather than applied retroactively.

5. Standards and Laboratory Testing

Each of the pilots will need to adhere to industry IT standards that provide direction to the industry on designing systems for integration between utilities and vendors. Having standards in place reduces costs and increases the chances for integration with other components or systems. Therefore, IT standards-related activities will be required in direct support of the pilot distribution projects. These activities include the following:

- Evaluate detailed standards specifications and perform mapping against pilot requirements.
- Perform cross-standards mapping to examine overlaps, interoperability, potential standards harmonization opportunities and/or co-existence issues.
- Define level of vendor compliance for standards-related features.
- Apply relevant standards to PG&E’s operating environment in support of the pilots and in conformance to standards.

Table 2-5 below represents the key standards at this point in time relevant to the pilot deployments.

TABLE 2-5
PACIFIC GAS AND ELECTRIC COMPANY
KEY STANDARDS RELEVANT TO THE PILOT DEPLOYMENTS

Line No.	Relevant Standards	Description of Standard
1	COMFEDE (IEEE C37.239)	XML format for various types of event data collected from electric power systems is defined.
2	IEC 61850	Suite of standards for the design of substation automation. Includes requirements, information models (node classes and data classes), and conformance testing.
3	DNP3, Secure-DNP3	Set of communication protocols typically used in SCADA systems, between a master terminal and remote substation or intelligent end devices. In standard networking terms, mostly a layer2 protocol.
4	IEC 61968-61970/Back-End EIM Impact, OpenSG, SGIP	Series of standards under development that define information exchanges between electrical distribution systems. CIM is maintained as a UML model used to derive design artifacts like XML schema.

Laboratory testing will also be required to test the proper function of the technology in use for the Line Sensors, VVO and Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project pilot deployments. This includes testing the installation of new technology components, proper electric system functionality, communications and software functions required. Specific electrical and IT testing of the software and devices will be based on the type of devices and vendor technologies selected in the analyze phase of each project.

The majority of the laboratory efforts for these projects are for the labor required to install the components, construct and execute the various tests, uninstall the components and collect, organize and report the results. In addition, specialized communications test equipment and software that is not currently available in PG&E's laboratory is included in the project scope.

Smart Grid Line Sensors (Labs & Standards)

Vendor applications will be installed in the lab for testing. These applications will be connected with the Distribution Test Yard (DTY) and test scenarios developed and executed to understand and characterize the operation of these applications. Functionality testing will include creating normal and abnormal conditions on the monitored circuits and evaluating the performance and accuracy of the products. The applications will be evaluated on the level of complexity in their installation and configuration as well as their operation. Data analysis and reporting functions will be evaluated.

The Smart Grid Line Sensor project includes testing of multiple communications technologies which are expected to include cellular, Silver Springs Networks (SSN) wireless mesh, narrow channel radio, and possibly others. Cellular and narrow channel radio are mature technologies that are used by the utility today for various communications solutions. The SSN wireless mesh is used by PG&E as its core electric SmartMeter™ network. Using this network technology to support communications for additional field applications has been envisioned to leverage additional capability from this technology. Other communications technologies, such as WiMax, may also be included in this testing.

Testing of the mature communication technologies involves ensuring that the devices are functioning according to their specifications. However, testing either the network technology or other emerging technologies involves more thorough and deeper testing. These uncertainties with the non-mature communications technologies need to be analyzed and tested as part of this pilot. This testing requires a large number of test cases to be developed and executed and will likely require an iterative approach to the testing as results from one set of tests will identify other tests that need to be executed.

<u>Voltage and Reactive Power (Volt/Var) Optimization Project (VVO) (Labs & Standards)</u>

Vendor applications will be installed in the lab for testing. These applications will be connected with the DTY and test scenarios developed and executed to understand and characterize the operation of these applications. Functionality testing will include creating normal and abnormal conditions on the monitored circuits and evaluating the performance and accuracy of the products. The applications will be evaluated on the level of complexity in their installation and configuration as well as their operation. Data analysis and reporting functions will be evaluated.

Additionally, the lab will perform an IT integration and scalability assessment of the vendor applications. The integration will quantify the ability of the vendor products to be integrated into the utility back office systems. The scalability assessment will provide guidance as to the ability of the vendor products to be able to support the size of PG&E's distribution system.

<u>Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Project (Labs & Standards)</u>

Vendor applications will be installed in the lab for testing. These applications will be connected with the DTY and test scenarios developed and executed to understand and characterize the operation of these applications. Functionality testing will include creating normal and abnormal conditions on the monitored circuits and evaluating the performance and accuracy of the products. The applications will be evaluated on the level of complexity in their installation and configuration as well as their operation. Data analysis and reporting functions will be evaluated.

The currently installed technology at many PG&E substations requires a manual activity after a fault to gather the engineering data that is available in the substation. The lab will prototype an automated function using a Complex Event Processor system that will automate the collection of the post-fault engineering data, combine this with the initiating fault data and transfer this data to the fault analysis application under test.

Additionally, the lab will perform an IT integration and scalability assessment of the vendor applications. The integration will quantify the ability of the vendor products to be integrated into the utility back office systems. The scalability assessment will provide guidance as to the ability of the vendor products to be able to support the size of PG&E's distribution system.

6. IT Project Costs

The technology costing process for the Smart Grid Distribution Pilot projects followed a three-step process. First, the high level business processes for the pilot projects where defined alongside the information/data reporting needs. Next, technology foundational areas requiring modification to support the projects were defined by technology domain. These include applications, information architecture, telecommunications, cyber security and standards and laboratory testing domains. Specific activities were defined within each technology domain across the "analyze, test and pilot deployment" phases for each project, as well as pre-deployment design activities to prepare for potential system deployment. As a final step, costs were derived across all activities within the technology domains based on hardware, software and labor requirements for each activity. Both estimated project management and O&M costs were included commensurate to the level of technology involvement in each project, as is standard to all PG&E technology-intensive projects.

G. Detailed Project Costs (Distribution and IT)

Smart Grid Distribution Pilot Project Costs by type of work, labor and materials are outlined in Table 2-7 following:

TABLE 2-7
PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID DISTRIBUTION PILOT PROJECT COSTS (DISTRIBUTION AND IT)

Line No.		2013	2014	2015	2016	Total
1	Distribution Labor Total	$2,451,845.3	$9,229,249.7	$6,062,222.2	$5,586,470.7	$23,329,788.0
2	IT Labor Total	3,642,716.7	11,703,439.9	4,567,924.4	4,734,885.2	24,648,966.2
3	Distribution Materials	562,304.6	5,442,576.6	1,962,312.0	1,584,000.0	9,551,193.2
4	IT Hardware	391,678.8	2,708,795.8	438,723.6	–	3,539,198.3
5	IT Software	1,091,464.7	2,162,247.8	–	–	3,253,712.5
6	Total by Year	$8,140,010.2	$31,246,309.8	$13,031,182.3	$11,905,355.9	$64,322,858.2
7	Total Running	$8,140,010.2	$39,386,319.98	$52,417,502.24	$64,322,858.17	
8	Distribution Maintenance	–	–	–	68,655.7	68,655.7
9	IT Maintenance	–	602,629.2	1,819,181.5	1,931,583.0	4,353,393.7
10	Total by Year	–	$602,629.2	$1,819,181.5	$2,000,238.7	$4,422,049.5
11	Total Running	–	$602,629.24	$2,421,810.77	$4,422,049.47	

H. Conclusion

PG&E selected these three Smart Grid Pilot Projects based on the drivers and elements of its Smart Grid Vision and deployment plan. These projects seek to pilot new Smart Grid Technologies that PG&E, and the industry generally, believes will make a significant positive impact over time in reducing costs that would otherwise be borne by customers, reliably managing increasing distributed renewable resources, improving electric system safety and improving customer reliability. PG&E's Smart Grid Pilot projects are pragmatic and focused to assist in meeting California's environmental and energy policies and providing foundational infrastructure to meet future changes in those policies.

PG&E's strategy is to proceed cautiously based on conservative benefit and cost analysis, and to test out and prove the feasibility of Smart Grid technologies prior to full scale deployment. This means that PG&E will perform an analysis on the status of these new devices within the industry, test individual device capabilities and integration within the lab, then pilot individual capabilities at a small-utility scale on multiple distribution circuits and then if benefits show the need for and benefits of further deployment, then deploy across its utility infrastructure after full review and approval by the CPUC as appropriate.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

TECHNOLOGY EVALUATION, STANDARDS AND TESTING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
TECHNOLOGY EVALUATION, STANDARDS AND TESTING

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
TECHNOLOGY EVALUATION, STANDARDS AND TESTING

A. Introduction

1. Background

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) proposed Smart Grid Technology Evaluation, Standards and Testing (TEST) initiative to support the Company's Smart Grid Pilot Deployment Project.

As described in Senate Bill (SB) 17, new technologies and capabilities consistent with the characteristics of a smart grid are key aspects of modernizing the electric system in California. The rapid evolution of the Smart Grid environment involves dramatic changes to the electric system, requiring substantial new long-term planning efforts and the ability to identify and integrate emerging technologies more effectively than ever before. In its Smart Grid Deployment Plan filed with the California Public Utilities Commission (CPUC or Commission) on June 30, 2011, PG&E identified a set of high-priority initiatives which provide new, incremental benefits to customers, energy markets and society as a whole by integrating advanced communications and control technologies to transform the operations of the electric system. PG&E applied a focused approach by selecting projects that have the potential to provide significant benefits to customers. However, some of the technologies proposed are relatively new or have not been proven in real-world operating environments. PG&E seeks to minimize the inherent risks associated with new technology by phasing the development and deployment of the projects.

This chapter describes the foundational Smart Grid TEST initiative to identify and evaluate promising new Smart Grid technologies, enable and facilitate adoption of emerging Smart Grid technology standards and verify the performance of emerging Smart Grid technologies in controlled test environments to prove the feasibility of Smart Grid projects prior to large-scale deployment. This initiative increases the Company's benchmarking and acquisition of Smart Grid technology expertise and know-how, and enables engagement with industry-wide Smart Grid technology experts, technology developers, and standard-setting bodies.

In Chapter 2 and 4 of this testimony, PG&E describes the four high-priority Smart Grid pilot projects it has chosen for initial testing and deployment under its Smart Grid Pilot Deployment Plan. These projects represent a subset of the technology roadmap PG&E proposed in its Smart Grid Deployment Plan,[1] which included 21 projects categorized across *Engaged Consumer, Smart Energy Markets, Smart Utility, and Cross-Cutting and Foundational* program focus areas.

The TEST initiative is separate but complementary to the four pilot projects. It is one of the *Cross-Cutting and Foundational* program initiatives included in PG&E's Smart Grid Deployment Plan and represents the capability beyond the other four pilot projects required to implement and coordinate PG&E's Smart Grid technology identification and evaluation, standards, and testing activities in other areas across all departments in PG&E over the 2013-2016 time period.

The TEST initiative builds on but does not duplicate the Smart Grid-related technology evaluation and innovation activities that have been funded or requested in other proceedings, including funding in PG&E's 2011 General Rate Case, SmartMeter™ cases, and Demand Response (DR) cases.[2] The capabilities are foundational to implementation of PG&E's Smart Grid Plan because they are necessary precursors to successful deployment of the Smart Grid initiatives described in the Smart Grid Deployment Plan, as well as to future PG&E Smart Grid initiatives and the application of approaches from other utilities and third-party technology developers to PG&E's system. In short, the TEST initiative is essential to PG&E's ability to learn about, acquire, test and leverage promising new Smart Grid technologies for the benefit of its customers and California.

The TEST initiative will provide a centralized organization for the Smart Grid technology evaluation and innovation activities at PG&E, helping

---

[1] Appendix A, pp. 121-152.

[2] See Section E2 of the policy chapter of this application.

identify and evaluate emerging technology projects, in order to achieve the desired strategic objectives set forth in the Smart Grid Deployment Plan. Specifically:

(a) By *creating the capacity to identify and coordinate Smart Grid technology activities* across PG&E, the TEST initiative will decrease the risks associated with managing diverse technology projects at different stages of maturity across multiple PG&E departments.

(b) By *actively promoting the use of newly-available data* across PG&E's operations, the TEST initiative will help achieve new benefits for customers.

(c) By *increasing PG&E's ability to leverage industry and publicly-funded Smart Grid research and demonstrations*, the TEST initiative will prevent PG&E from spending resources on duplicative efforts to those done elsewhere, and will help PG&E make use of the best available Smart Grid technology at a lower cost to its customers.

(d) By *focusing PG&E's standards development and compliance certification efforts* in areas not previously possible, the TEST initiative will shape the future of Smart Grid technology holistically to maximize interoperability, minimize technology selection risk and reduce implementation costs for customers.

(e) Finally, *by providing testing resources beyond current activities to reduce the implementation risk of new and emerging technologies*, this initiative will improve the effectiveness and reduce the cost of future large-scale Smart Grid deployment efforts.

This TEST initiative is an essential investment for PG&E to make today in order to continuously improve the safety, reliability and customer focus of PG&E's operations, even while the grid is being transformed to empower customers and respond to new demands. PG&E needs to operate its existing systems efficiently and to make renewable resources an ever-expanding part of the energy mix. By continuing to build a strong foundation now, PG&E will be better prepared to meet demand, fill technology gaps, and enable a stronger and more resilient infrastructure for its customers.

2. Organization of the Chapter

The remainder of this chapter is organized as follows:

- Section B – Need Assessment
- Section C – Proposed Smart Grid TEST Initiative
- Section D – Estimated Costs Requested in This Chapter

B. Need Assessment

When implementing new technology, companies inevitably face a set of execution risks due to the fast-paced and unproven nature of technological change. For PG&E, the potential risks associated with future Smart Grid investments could include such problems as: (1) selecting less effective technologies or systems that could adversely impact reliability, safety, security or customer data privacy; (2) deploying technologies that require costly upgrades, maintenance, or replacement sooner than expected; (3) paying for unnecessary technology that provides less benefit than expected; or (4) failing to design deployments in a way that maximizes the benefits to customers, markets, or other stakeholders.

Beyond the individual project risks, planners in the Smart Grid environment face the larger challenge of managing long-term technology identification and development across a wide-ranging set of domains. These domains include such diverse areas as power engineering, automation, telecommunications, information systems, Transmission and Distribution (T&D) operations, energy efficiency and DR programming, electric vehicle integration, and energy procurement. Within each of these different realms, technologies also vary dramatically in their maturity, from the earliest proof-of-concept to somewhat tested to widely deployed.

As the complexity of the utility infrastructure increases, there is a significant need to test and pilot systems and equipment in an “end-to-end” fashion to reduce risk, ensure benefits and manage costs. As the Smart Grid environment integrates grid infrastructure with advanced communications and control technology, PG&E’s technology evaluation capabilities must be enhanced to test new types of equipment, work processes and integrated systems. With this project, PG&E seeks to combine capabilities into a single responsible organization. PG&E’s proposed Smart Grid staff will leverage existing facilities to investigate and test new Smart Grid devices, equipment, communications, applications, and systems in an integrated manner that models the Smart Grid and the new customer, market and utility interactions.

This initiative is required in order to achieve alignment between PG&E's needs and the Smart Grid solutions currently being developed and commercialized in the marketplace. By testing and maturing products at small scale and in a controlled environment, this initiative will reduce the risks and costs associated with these technologies, when deployed at large scale into production systems.

By deliberately specifying and coordinating the resource requirements associated with technology identification and development, PG&E expects to successfully achieve the simultaneous development of multiple Smart Grid capabilities across a number of different program areas.

C. Proposed Smart Grid TEST Initiative

1. Proposed Initiative

PG&E proposes to create a foundational Smart Grid TEST capability to support the successful deployment of Smart Grid initiatives as described in the Smart Grid Deployment Plan, as well as new initiatives that will emerge in the future. This TEST initiative has five components:

(a) Creating and coordinating Smart Grid technology identification and development across PG&E.

(b) Leveraging data from newly deployed technology and infrastructure throughout PG&E's operations and services.

(c) Applying external research and demonstrations from industry and publicly funded projects to improve PG&E's operations.

(d) Expanding PG&E's engagement in standards development efforts and supporting compliance certification activities not currently covered.

(e) Reducing the risk of new and emerging technologies through an "end-to-end" technology evaluation and testing capability.

a. Creating and Coordinating Smart Grid Technology Identification and Development Across PG&E

PG&E will require new staff to implement this initiative, under the leadership of a new program manager for Smart Grid TEST. It is essential that a single program manager be established to manage and coordinate these activities. Without such a position, it is unlikely that this evolving technology identification and development will successfully translate into PG&E's Smart Grid objectives or the expected benefits for customers.

PG&E staff directed by the new program manager will further develop PG&E's Smart Grid technology roadmap, identify appropriate projects, plan and schedule projects, solicit additional funding from partners and government agencies where appropriate, provide project test plans, and coordinate and collaborate with vendors and other parties.

PG&E staff will coordinate these new activities across the multiple disciplines relevant to the Smart Grid, including electrical power systems, Information Technology (IT), and communications technology. PG&E does not currently staff a focused initiative as proposed here. A broad and sustained approach is critical for the level of technology change that is being driven by the Smart Grid.

Through increased coordination of Smart Grid technology identification and development, PG&E expects to realize a number of customer benefits. These include: new, incremental benefits from newly deployed technology, infrastructure and data (already paid for through approved projects such as the SmartMeter™ project); lower costs as a result of improved operational efficiency; avoided costs of selecting the wrong technology and having to change course later; and greater reliability, safety, security, and customer data privacy.

PG&E will require 0.5 Full-Time Equivalents (FTE) of program management staff in the first year and 1.0 FTE in the following three years.

b. Leveraging Newly Available Data Throughout PG&E's Operations and Services

The availability of data from new infrastructure (such as SmartMeters™, expanded substation Supervisory Control and Data Acquisition, and distribution automation equipment) presents significant opportunities for operational improvement within PG&E's operations and services. These improvement opportunities include not only those envisioned during original project planning, but also new and emerging opportunities that arise from innovative types of analysis. After many decades of having only limited monthly usage data from electromechanical meters, PG&E now has a wealth of data from which it can derive fresh insights. However, moving beyond traditional patterns of activity often requires new approaches. Achieving operational improvements of these kinds requires focused staff that can actively promote the availability of new data, and help support the development of new applications and services using such data.

There are many domains within PG&E's operations where benefits from new types of analysis are expected. For example, PG&E may be able to further improve T&D system demand forecasting and load profiling to improve operations. Electric Vehicle (EV) charging is an area with significant potential for adverse grid impacts that can be more thoroughly understood by analyzing emerging data streams as EV penetration increases. Finally, PG&E expects to find new applications for data to improve the integration of renewable resources such as more accurate and timely information about customer-owned generation output and actual operating parameters.

Understanding and utilizing new data can be enhanced through advanced visualization systems that translate raw data into pictorial and graphical forms for easy pattern recognition. A significant amount of the new Smart Grid data will be location-based, and advanced designs for fully utilizing location-based information will be needed. Additionally, real-time digital simulations are an emerging analysis tool that PG&E expects to apply and continue developing to better understand the grid impacts of new technology.

PG&E will require 0.25 FTE of program management staff and 0.5 FTE of new engineering staff, per year over the 4-year period for this component of the TEST initiative.

c. Applying Industry and Other External Research and Demonstration to PG&E's Operations

The rapid evolution of the Smart Grid environment is taking place across a wide playing field encompassing private industry (utilities, telecom companies, device manufacturers, and others), the public sector (federal and state agencies), and nonprofit organizations (research consortiums, standard-setting entities, etc.). Substantial sums of research funding are already flowing into Smart Grid projects in the industry from many sources. In order to achieve the highest possible level of benefits from these industry activities for customers, PG&E needs to be aware of and engaged in the most relevant industry consortia, and to have at its fingertips the most recent results of publicly and privately-funded research activities. To avoid duplication of activities, PG&E must be fully informed about the latest research and demonstration efforts. These include projects funded by the Department of Energy's (DOE) Smart Grid Investment Grant and Smart Grid Demonstration Grant programs, California agency-managed research projects, as well as the efforts at DOE's national labs (Sandia, Pacific Northwest National Laboratories, National Renewable Energy Laboratories and others). In addition, privately funded research organizations like the Electric Power Research Institute manage research programs through a consortium of industry participants who create and carry out shared research agendas in electric transmission and distribution, new end-uses and renewable resource integration.

Through this proposed program element, new program staff will engage in technology scanning, industry peer visits, benchmarking and collaborative efforts, in order to learn from the work others have already done. In addition, PG&E plans to ramp up its efforts to attract outside funding (non-ratepayer dollars) through grants offered by state agencies, the DOE, and others. This may include contributing in-kind resources such as staff time or test facilities, and small amounts of money toward early-stage "matching grant" opportunities. In this way, PG&E can more proactively influence the research and development agenda to address the challenges faced in its service territory.

PG&E expects that gaining greater visibility into industry and publicly-funded research will provide: (1) cost savings for customers by not conducting unnecessary research; (2) lower-cost technology evaluation through leveraging dollars already being spent by others to study technologies relevant to PG&E customers; and (3) improved operations as a result of importing others' successful practices.

PG&E will require 0.5 FTE of program management staff for four years, and 0.5 FTE of engineering staff for the first two years for this component of the TEST initiative. PG&E also proposes $1.50 million of other program expense such as funding for research cost sharing over the four years, for this component. The total cost will be $2.42 million.

d. Expanding Standards Development and Compliance Certification

The size and diversity of the Smart Grid environment—referred to by some as a "system of systems"—presents challenges to successful and secure integration. However, this integration is critical to deriving the full benefits of new technology for customers and utility operations. In order to achieve integration and interoperability, the Smart Grid must be governed by a unifying set of standards, protocols and interfaces. While a few existing standards may provide guidance for certain devices or technologies, much of the emerging Smart Grid requires the creation of new standards.

Technology vendors, such as device manufacturers and telecom providers, release new products into the market as quickly as possible in order to capture maximum commercial advantage. Vendors' interests, however, do not always align with utility customer expectations for security, privacy, interoperability, reliability, and safety. Furthermore, a competitive marketplace requires durable, flexible solutions that are not tied to specific vendors or proprietary technologies. Building a foundational platform of standards creates an environment in which product developers can build and innovate, knowing more clearly what shared capabilities are required for widespread adoption. This is especially important given how much of the Smart Grid benefits are dependent upon "network effects" (under which products provide value in direct proportion to the extent of adoption by other users, e.g., smart phones or text messages).

Within utilities such as PG&E, adoption of a technology standard goes through a number of steps, beginning with the development of the business case and use case for a product class, followed by the documentation of commercial and technical requirements, and then technical specifications. Then, once a technology prototype has been developed to deliver the necessary requirements consistent with the technical specifications, it must undergo certification testing. Finally, interoperability testing verifies that devices from multiple vendors which are certified to a particular technical specification can operate effectively together under that specification.

In 2007, recognizing the challenge of developing standards for emerging technologies across the energy industry nationwide, the U.S. Congress assigned coordinating responsibility to the National Institute of Standards and Technology (NIST). Accordingly, NIST engages stakeholders in participatory public processes to identify applicable standards, gaps in currently available standards, and priorities for new standardization activities. NIST's 18 Priority Action Plans[3] provide a comprehensive agenda for coordinated standards development across multiple technology areas, and PG&E has begun to align its Smart Grid standards architecture with NIST while also participating in the NIST standards process. While NIST coordinates the development of standards, it does not actually issue and maintain standards. That responsibility lies with standard specification and development organizations that participate in NIST-sponsored processes.

At present, PG&E staff contribute in some way to more than 50 standards development working groups, convened by organizations such as those highlighted in Table 3-1.

[3] http://www.nist.gov/smartgrid/priority-actions.cfm.

TABLE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
EXAMPLE STANDARDS DEVELOPMENT GROUPS – TABLE

Line No.	Standards Bodies	Description	Example Standards/ Guidelines
1	NIST Smart Grid Interoperability Panel	Assesses changes in technologies and requirements, and coordinates with standards setting organizations to support timely availability of needed standards.	NISTIR 7628
2	Open Smart Grid (OpenSG) (Program of the UCA International Users Group	Association of utility user and supplier companies dedicated to promoting the integration and interoperability of electric/gas/water utility systems.	OpenADR
3	ZigBee Alliance	Industry association developing an IP networking stack and application.	Smart Energy 2.0
4	Society of Automotive Engineers (SAE)	Defines standards for electric vehicle charging and 2-way communication with the vehicle and substation/transformer.	SAE J2847
5	Internet Engineering Task Force	Organization behind the Internet as it is known today and tasked with extending the Internet beyond computing to a broader array of devices (the Internet of Things).	IPv6
6	IEEE Standards Association	Signifies that the IEEE believes the document to be consistent with good engineering practice and represents a consensus from materially affected industries, governments, or public interests.	IEEE 802.15
7	International Electrotechnical Commission (IEC)	International organization providing standards and conformity assessment for all electrical, electronic and related technologies.	IEC 61850

To date, as described in its semi-annual SmartMeter™ program report filed with the Commission, PG&E has focused its attention on standards development in the Home Area Networking (HAN) and Open Automated Data Exchange (OpenADE) areas, through such groups as the ZigBee Alliance and OpenSG. These efforts have been necessary to support the rollout of SmartMeters™ and the Commission's requirements for HAN capabilities. Under this application, PG&E will not conduct work on HAN or OpenADE standards which are already funded in the SmartMeter™ project. Instead, PG&E proposes to focus on the evolution of existing standards for next-generation use cases, as well as the development of new standards, for areas where PG&E has not yet engaged, including the following:

- Advanced distribution and substation automation
- Next-generation telecommunications
- Electric vehicle charging and communications
- Data management and integration

For the purposes of this application, PG&E has assigned costs for standards development on a project-specific basis to the four proposed pilot projects described in this application with immediately foreseeable needs. Chapter 2 addresses the standards work necessary to support the three T&D pilots proposed in this application. These efforts fall primarily into NIST Priority Action Plan areas #8, #12 and #14. Chapter 4 addresses the standards activity relevant to more granular load forecasting using SmartMeter™ data, primarily aligned with Priority Action Plan areas #9 and #17.

In this chapter, PG&E proposes to support new PG&E staff to conduct incremental efforts which are foundational to PG&E's Smart Grid deployments, but which are not covered in other chapters of this application or in prior applications to the Commission. Some of the specific areas for future standards work are known to PG&E today. For example, areas known to be of longer-term importance, but not yet addressed by any PG&E resources include NIST Priority Action Plan #2 for improving standards for new wireless technologies (Satellite, WiMAX, LTE) which are expected to be part of PG&E's longer-term telecommunications roadmap; and Priority Action Plan #11 for creating a common interoperable model for EV charger pricing, billing, and DR participation. Other areas of emerging focus are expected to surface in the later years of PG&E Smart Grid deployments (2016 and beyond).

PG&E has placed a high priority on cyber-security for its Smart Grid deployments. The company's approach to Smart Grid cyber-security is outlined in the Smart Grid Deployment Plan,[4] and is designed to leverage and extend the work completed by NIST in the NISTIR 7628, evolving NERC CIP guidance, DOE specific guidance (such as the

[4] Appendix A, pp. 217-246.

emerging Electricity Sector Cyber-Security Risk Management Process Guideline), ASAP-SG security profiles, and detailed IEC standards. PG&E actively tracks these types of standards and guidelines to ensure that they will be appropriately applied in the Smart Grid environment. While cyber-security standards development activities for the four specific projects proposed in this application have been planned for those projects, there remains additional effort to align, contribute, and shape the work being completed by these bodies today to future efforts as part of this specific Testing and Standards project. In addition, ensuring alignment of the emerging specific T&D standards to the security standards is an activity that is deemed important for PG&E to integrate these requirements into existing processes and technology specifications to ensure that the principle of security by design is not solely focused on individual projects but becomes part of the continuous cycle of vetting and reducing the risk of new technologies for the Smart Grid.

PG&E's standards activity also includes compliance certification and interoperability testing of new technologies. New technologies must be tested to ensure that they perform to the standards that vendors claim, for instance Federal Communications Commission standards for Radio Frequency emissions, or the DNP3 standard for interoperability between substation equipment. In many cases, PG&E must either perform compliance certification on new technology itself, or pay for vendors or others to do the certification. Depending on the size of the vendor, PG&E may also need to purchase the technology it wishes to test. This program will support compliance certification for new and emerging Smart Grid technologies, including efforts to build more rigorous compliance test cases into the standards specifications processes, to reduce the cost of testing incurred by PG&E and its customers.

In addition, PG&E proposes an up-front "standards initiatives assessment" that identifies gaps in PG&E's current standards activities and the myriad of standards development activities underway in the industry beyond those PG&E is already actively participating in. This will enable a more comprehensive roadmap for Smart Grid standards development activities at the company. The proposed new staff will then coordinate the resources necessary for development, certification and/or interoperability testing across the priority standards areas.

This program is also intended to support increasing PG&E's influence in national standards leadership efforts, such as NIST's governance committees. PG&E must take an active role in standards bodies decided by NIST as fulfilling any crucial piece of the Smart Grid vision, since these bodies shape and influence the future of the industry.

PG&E expects that increased efforts in standards development and compliance certification will provide technology deployment that delivers the security, privacy, reliability, safety performance that customers expect; flexible and lower-cost solutions that aren't tied to specific vendors or proprietary technologies but rather emerge from a competitive market for innovation; and a higher likelihood of integrative benefits from the broader Smart Grid vision. PG&E's test results may also help reduce implementation costs and risks for new Smart Grid initiatives industry-wide.

There are direct advantages to PG&E of engaging in standards, as well as significant risks and disadvantages to not doing so. Such risks could include: Smart Grid solutions failing to operate in a secure and reliable manner; a lack of alignment between PG&E technologies and future regulations, requiring expensive rework to achieve compliance; and/or a lack of preparedness to deploy emerging technology on the timeframe expected by customers and regulators. Consequently, it is critical to drive development and track progress on numerous standards which are of importance to PG&E's Smart Grid initiatives.

PG&E will require 2.5 FTE of technical staff in the first year, and 1.75 FTE in the second and third years for this component.

e. Reducing the Risk of Smart Grid Technology Implementation Through Technology Evaluation and Testing

Under this TEST initiative, PG&E will add Smart Grid staff to utilize its existing test lab facilities, in order to verify the performance of new and emerging technologies through an "end-to-end" Smart Grid testing environment. This staff would be incremental to the staff proposed in the other chapters of this application, as well as other applications to the Commission.

This program will quantify the effectiveness and maturity level of technology applicable to the Smart Grid program, working closely with vendor and industry peers to test their products at small scale in production-like situations. While some projects will be performed as a verification that the vendor product works as expected, other projects will be performed as collaborative efforts with vendors and industry peers as Proof of Concept projects that extend or enhance the capabilities and functionality beyond what is currently available.

Testing projects will be staffed by new positions, and will be conducted over periods from a few months to a year. The proposed new staff will not be dedicated to specific project areas, but will be utilized in various projects on an as-needed basis. FTE figures are used for estimation purposes to indicate the level of staffing required to conduct testing across the program areas of interest.

In summary, PG&E will add staffing capacity equivalent to 4 to 5 FTEs over the course of the initiative. For each testing area, this team of engineers and technicians will identify technology alternatives, decide on vendor products or prototypes to test, install the devices, create a test plan, conduct the technology test (including security), and create a written report on the test results.

PG&E also expects to incur a total of up to $450,000 per year of capital spending to support testing activities. Each small project is estimated to require up to $50,000 to purchase the equipment or devices that will be subject to testing and potentially new test equipment, based on past experience with technology testing. Where possible, PG&E will attempt to obtain prototype equipment directly from vendors at no charge. Where necessary, PG&E will pay for new equipment. Some purchased equipment will be useful across multiple test areas, providing some economies of scale.

PG&E envisions technology evaluation and testing projects that will include, but not be limited to, the following areas:

(1) Integrating the Increasing Penetration of Distributed Renewable Resources.

(2) Integrating Distributed Storage and Advanced Distribution Automation.

(3) Integrating Electric Vehicles Into Grid Operations.

(4) Coordinating Communication and Control Equipment Development and Specifications.

(5) Meeting Emerging and Expanding Smart Grid Cyber-Security Requirements.

(1) Integrating Increasing Penetration of Distributed Renewable Resources

Renewable generation is an ever-expanding part of the generation mix for PG&E, California and the nation. Small-scale renewable generation can provide direct benefit to the individual customer. However, when customers employ distributed renewable generation products, their use of the electric grid changes.

PG&E has the responsibility to safely and efficiently manage the distribution grid so that all customers receive high quality and reliable power to meet their needs. This becomes more challenging as the level of distributed generation on the distribution grid increases. Control systems on the distribution grid will need to be enhanced with new types of sensors and monitoring technologies, and new types of automated control systems will be required to react with sufficient speed to mitigate the impacts of these renewable resources on the grid such as changing voltage levels.

This program will characterize the performance of renewable resources in terms of voltage, power output, transient analysis and post-outage recovery. New sensors and monitoring systems will be tested to identify which are most appropriate for deployment. Smart Inverters will be tested to understand the capabilities and limitations. New grid and equipment control systems will be tested to understand how they react to and compensate for these variable conditions, including control leveraging existing SmartMeters™.

PG&E will require $1.45 million of incremental labor expense and $400,000 of new capital over the period 2014-2016 for this component of the TEST initiative.

(2) Integrating Distributed Storage and Advanced Distribution Automation

The storage of electrical energy within the electric grid has not generally been performed due to the high cost of energy storage solutions. However, intermittent distributed renewable generation can be better managed if combined with energy storage, leading to new investments by manufacturers and utilities into energy storage solutions. PG&E will test and characterize the impact of distributed storage (as stand-alone and as part of distributed generation systems) on the distribution grid. This application does not propose to evaluate different types of storage technologies, but rather how energy storage is integrated into the grid and operations.

Further, energy storage alters both the static and dynamic compensation systems on the distribution grid. New and enhanced distribution automation equipment and more sophisticated control systems (distributed equipment controllers and Distribution Management System upgrades) will be necessary to properly integrate energy storage into the grid at the appropriate locations, with the appropriate modifications to the grid and with the appropriate control systems and strategies in place.

Testing will include various deployment scenarios of energy storage and energy storage with distribution automation equipment, in order to better prepare for the impact of increasing storage interconnection by customers.

PG&E will require $1.38 million of incremental labor expense and $450,000 of new capital over the period 2014-2016 for this component.

(3) Integrating Electric Vehicles Into Grid Operations

Electric Vehicles introduce large, variable loads to the electric distribution system. Investigations into the effects on the distribution system at various points relative to the load will be conducted, and simulations will be developed that reflect the results of the physical testing. The feasibility of and necessity for technologies to communicate with EV charging controllers to manage these loads will also be investigated.

Specific activities to be conducted include: testing of EV charging system effects on customer systems, on localized portions of distribution circuits, and on overall circuit performance; comparisons of physical tests with simulation models to understand correlation and validate models; investigation of integrated charging control through the SmartMeter™ system; investigation of localized charging control by applications in the meters that monitor the current voltage conditions on the local circuit; and testing of emerging standards for communications between utilities and EVs through multiple communications paths (mesh radio, WiFi, cellular) for both control and providing information to customers.

PG&E will require $0.50 million of incremental labor expense and $75,000 of new capital over the period 2014-2016 for this component of the TEST initiative.

(4) Coordinating Telecommunication and Control Equipment Development and Specifications

PG&E employs a number of communications technologies to provide service throughout our service territory. Many of these technologies are mature (e.g., fiber optic, single channel radio, code division multiple access cellular), but others are emerging with limited integration into electric system operations (e.g., WiMax, multichannel mesh radio, 4G cellular). In addition, even mature communications technologies may require enhancements to meet the more stringent cyber-security requirements that are also evolving along with the Smart Grid. A key direction that the industry is moving is to leverage more of the internet-based technologies and protocols across larger portions of the utility communication systems. This direction may lead to lower cost and more interoperable and secure communications systems over time.

In addition, command and control systems, such as a Distribution Management System (DMS), are evolving to support new Smart Grid technologies. This testing area will evaluate intelligent control devices that handle control at the substation level and then communicate upstream with a DMS. Under these hybrid centralized and distributed control systems, intelligent field devices and substation-level devices perform localized decision making, while also coordinating with higher level systems that maintain a broader view of the distribution system.

PG&E will require $0.50 million of incremental labor expense and $125,000 of new capital over the period 2014-2016 for this component of the TEST initiative.

(5) Meeting Emerging and Expanding Smart Grid Cyber-Security Requirements

Advancing the Smart Grid begins with a foundational level of investment in a core set of IT security capabilities that will securely enable the Smart Grid initiatives while also providing the robust, adaptive platform to grow and scale in the face of evolving cyber-threats to the utility industry.

PG&E's Smart Grid Deployment Plan[5] identified a set of 16 security domains for investment, which PG&E expects to form the basis of the system-of-systems architecture. While capabilities currently exist in many of these areas, further investment will extend the company's capabilities to incorporate the fundamental design differences required for the evolving Smart Grid.

While some security components have been built into the four pilot projects proposed in other chapters of this application, this program envisions additional resources to support PG&E security

[5] Appendix A, pp. 234-235.

testing on emerging Smart Grid system components, as well as prototype tools, development and testing.

PG&E will require $0.79 million of incremental labor expense and $125,000 of new capital over the period 2014-2016 for this component of the TEST initiative.

TABLE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED TECHNOLOGY EVALUATION AND TESTING
(REDUCING RISK THROUGH EVALUATION AND TESTING
SUMMARY OF REQUESTED COSTS)
($ MILLION)

Line No.		2014	2015	2016	Total
1	Labor Expense				
2	Integrating Distributed Renewable Resources	$0.32	$0.50	$0.62	$1.45
3	Integrating Distributed Storage and Advanced Distribution Automation	0.32	0.43	0.62	1.38
4	Integrating Electric Vehicles Into Grid Operations	0.16	0.17	0.17	0.50
5	Coordinating Telecommunications and Control Equipment	0.16	0.17	0.17	0.50
6	Meeting New Smart Grid Cyber-Security Requirements	0.25	0.26	0.27	0.79
7	Total Labor Expense	$1.23	$1.54	$1.87	$4.63
8	Capital Expense				
9	Integrating Distributed Renewable Resources	$0.100	$0.150	$0.150	$0.400
10	Integrating Distributed Storage and Advanced Distribution Automation	0.150	0.150	0.150	0.450
11	Integrating Electric Vehicles Into Grid Operations	0.025	0.025	0.025	0.075
12	Coordinating Telecommunications and Control Equipment	0.050	0.05	0.025	0.125
13	Meeting New Smart Grid Cyber-Security Requirements	0.050	0.05	0.025	0.125
14	Total Capital	$0.38	$0.43	$0.38	$1.18
15	Total Technology Evaluation and Testing Cost	$1.60	$1.96	$2.24	$5.80

2. Initiative Benefits and Potential Improvements

The proposed TEST initiative is designed to achieve an important set of objectives for PG&E's operations and services, by creating and coordinating Smart Grid technology identification and development across PG&E, increasing engagement with industry research and standards development efforts, and reducing risks of implementation of new and emerging technologies through a dedicated evaluation and testing environment.

Through increased coordination of Smart Grid innovation, PG&E expects to realize the following benefits for customers:

- New, incremental benefits from newly deployed technology, infrastructure and data (already paid for through prior mechanisms such as the SmartMeter™ project).
- Lower costs as a result of improved operational efficiency.
- Avoided costs of selecting the wrong technology and having to change course later.
- Greater reliability, safety, security, and privacy.

In addition, PG&E expects to achieve compliance with important policy directives contained in SB 17.

Specifically, PG&E expects that gaining greater visibility into industry and publicly funded research will provide: avoided costs for customers by not conducting unnecessary development work; lower-cost technology evaluation through leveraging dollars already being spent by others to study technologies relevant to PG&E customers; and improved operations as a result of importing others' successful practices. It is important to PG&E not to duplicate research efforts that have already been funded elsewhere.

PG&E expects that increased efforts in standards development and compliance certification will provide: technology deployment that delivers the security, privacy, reliability, and safety performance that customers expect; flexible and lower-cost solutions that aren't tied to specific vendors or proprietary technologies but rather emerge from a competitive market for innovation; higher likelihood of integrative benefits from the broader Smart Grid vision. PG&E test results may also help reduce implementation costs and risks for new Smart Grid initiatives industry-wide. By investing in standards development, PG&E complies with SB 17 policy directives for "dynamic optimization of grid operations and resources, with cost-effective full cyber security" and the development of "standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid."[6]

PG&E expects that technology evaluation and testing protocols will improve safety and reliability in its deployments of Smart Grid technologies, ensuring that unproven technologies or system architectures do not threaten public safety or system reliability. In addition, this focus on testing is designed to lower overall costs of Smart Grid projects by reducing the risk of large-scale capital investments in unproven or unready technologies.

Should PG&E not proceed with this initiative, PG&E expects to face heightened risks of the following types: suboptimal technology choice that undermines reliability, safety, security or privacy; higher costs of subsequent replacement; technology that provides fewer benefit to customers; and possible failure to gain full benefits or comply with policy directives (such as those governing interoperability, cyber-security, or increased penetration of renewable technologies).

---

[6] SB 17, Chapter 4 (a) and (i).

D. Estimated Costs Requested in This Chapter

1. Summary of Costs Included in This Chapter

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF TEST INITIATIVE IMPLEMENTATION COST
($ MILLION)

Line No.		2013	2014	2015	2016	Total
1	Creating and Coordinat. Smart Grid Tech. Identification					
2	Labor	$0.14	$0.30	$0.31	$0.32	$1.06
3	Leveraging Newly Available Data					
4	Labor	$0.23	$0.24	$0.24	$0.25	$0.96
5	Applying External Research to PG&E Operations					
6	Labor	$0.30	$0.31	$0.15	$0.16	
7	Other Expense (External Research Cost)	0.75	0.50	0.25		
8	Subtotal	$1.05	$0.81	$0.40	$0.16	$2.41
9	Expanding Standards Development and Compliance					
10	Labor	$0.89	$0.64	$0.67	–	$2.20
11	Reducing Risk Through Evaluation and Testing					
12	Labor		$1.23	$1.53	$1.87	
13	Capital Equipment	–	0.38	0.43	0.38	
14	Subtotal	–	$1.60	$1.96	$2.24	$5.80
15	Total Labor Expense	$1.56	$2.71	$2.91	$2.60	$9.78
16	Total Other Expense	$0.75	$0.50	$0.25	$0.00	$1.50
17	Total Capital	$0.00	$0.38	$0.43	$0.38	$1.18
18	Total Initiative Cost	$2.31	$3.59	$3.58	$2.98	$12.45

2. Risk and Uncertainties Related to Estimated Costs

This proposed TEST initiative addresses new and less developed technologies in areas where less is currently known. The purpose of the testing activity is to evaluate the performance and estimate the benefits delivered for a given technical configuration. The installation process and bill of materials for a given technology application are not known at the point when the lab work begins. As a result, costs cannot be forecast with as much precision as for other chapters. Subsequently, PG&E will develop technology pilots with a better sense of the required costs for installation (labor) and equipment.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

SHORT-TERM DEMAND FORECASTING

SMART GRID PILOT PROJECT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
SHORT-TERM DEMAND FORECASTING
SMART GRID PILOT PROJECT

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
SHORT-TERM DEMAND FORECASTING
SMART GRID PILOT PROJECT

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) Short-Term Demand Forecasting Smart Grid Pilot Project (Project), and request authorization from the California Public Utilities Commission (CPUC or Commission) of $14.1 million in incremental funding to implement this pilot project from 2013 through 2016. As part of this Project, PG&E proposes to evaluate whether there are benefits from using more granular sources of data to forecast PG&E's bundled customer demand for use in the California Independent System Operator (CAISO) markets. The sources of additional data PG&E will use in this Project include, customer demand data from SmartMeters™, Supervisory Control and Data Acquisition (SCADA) data from PG&E's transmission and distribution network, bundled customer enrollment data, and data from PG&E's Demand Response (DR) programs.

As part of this Project, PG&E will analyze, test, build, and then pilot systems incorporating more granular sources of data for a specific region in PG&E's service territory. By doing so, PG&E will be able to demonstrate and evaluate the costs and benefits of using more granular information for the purposes of forecasting short-term electricity demand used to inform daily electricity procurement activities. If warranted by the cost and benefit estimates derived from the Project, PG&E will then pursue broader, systemwide deployment in a later phase. This is consistent with PG&E's Smart Grid strategy, which provides for the Company to pilot and de-risk technologies and processes new to PG&E by confirming their effectiveness to deliver safe, reliable, and cost-effective energy services to customers.

The Project that PG&E proposes in this chapter is incremental to PG&E's baseline Smart Grid projects and builds on other baseline projects. For example, increased penetration of SmartMeters™ in PG&E's territory as well as increased SCADA at distribution substations, yield new sources of granular information that can be used to inform and potentially improve electricity demand forecasts.

The remainder of this chapter is organized as follows:

- Section B – Needs Assessment
- Section C – Proposed Project
- Section D – Project Benefits
- Section E – Estimated Project Costs
- Section F – Conclusion

B. Need Assessment

PG&E procures electricity on behalf of 5.1 million bundled customers throughout its 70,000 square mile service area in northern and central California. In order to provide sufficient electricity service to all of its bundled customers, PG&E must procure and distribute enough energy to match customer demand. Customer electricity demands fluctuate significantly based on changing weather conditions, time of day, season, and other variables. The ability to forecast demand day-ahead and near-real time is important for PG&E to provide reliable and efficient electric service to its customers.

Currently, PG&E utilizes demand forecasts for procurement and planning purposes. The proposed Project focuses on the short-term forecasts ('operational forecasts') used for day-ahead and real-time procurement of electricity from the CAISO markets.

Historically, PG&E has used a "top-down" approach to forecast short-term electricity demand for bundled customers. This is a standard method used by other load serving entities. Using this approach, PG&E forecasts day-ahead and near real-time demand using SCADA load data calculated by adding in-area generators and net flows on transmission lines that interconnect PG&E with other service areas. This SCADA load information, both historical and close to real-time, along with additional information such as the average forecast temperature within PG&E's service area are fed into a model to produce an overall service area forecast. A PG&E bundled customer forecast is then prepared for procurement purposes by removing non-bundled electric demand and adjusting to remove transmission losses.[1]

While this approach has produced reasonable demand forecasts, it does not directly capture the specific impacts of micro-climates within PG&E's service area. For example, the weather effects of coastal fog are currently combined with the effects of high temperatures in the Central Valley to determine an aggregate temperature index for the entire service area. Given the differences in the micro-climates, PG&E may be able to improve the accuracy of its bundled customer demand forecast using more granular demand information. The sources of granular information are transmission network, distribution network, SmartMeters™, and weather data. However, before implementing a new forecasting technique that uses more granular inputs for the entire service area, PG&E believes it would be prudent to test and pilot the new forecasting process in a subset of PG&E's service area (or region) to determine whether to fully deploy this new forecasting technique.

C. Proposed Project

The objective of the proposed Project is to evaluate if more granular sources of data can be acquired and used to improve the accuracy of PG&E's short-term electricity demand forecasts. The Project will follow a three phase approach to analyze, build, and pilot the data acquisition, modeling, and forecasting activities.

In the analysis phase, PG&E will select a region for forecasting and identify the existing data sources available to prepare a forecast. The data, compiled across multiple existing platforms, will be extracted, analyzed, validated, and cleansed where necessary. In the build phase, PG&E will integrate the many data sources into a central repository where the raw data will be processed and housed for input into a demand forecasting process. In the pilot phase, PG&E will run, in parallel with its existing forecasting process, a separate forecast using more granular inputs for the region selected for the pilot, making adjustments to software as needed, and compare the forecast with the existing forecasting

[1] Transmission losses are the loss in energy due to the electrical resistance of transmission lines and other components of the electric grid.

process. The following section provides more detail on the three phases of this Project.

1. Analyze Phase

In this first phase, PG&E will determine the region to be used for the Project. PG&E intends to use a number of criteria to select the region for the pilot, such as:

- Region with a maximum of 500,000 customers.
- Region with available transmission historical demand data.
- Region with a high percentage of deployed distribution automation systems.
- Region with a high percentage of deployed SmartMeters™ and/or customer interval meters.
- Region where the SmartMeters™, distribution sub-stations, and transmission sub-stations can be electrically isolated.
- Region with as much historical data (preferably with at least three years of data) as possible for the above items.

Selection of an appropriate region is an important step to be able to conduct an effective pilot. By piloting in a region that is already well instrumented with technology that generate telemetry data, PG&E will be able to develop more meaningful analytics to train the forecasting model while also leveraging existing baseline investments in Smart Grid.

Once an appropriate region has been selected, PG&E will determine the quality of the data from the existing transmission and distribution SCADA, SmartMeter™, and other existing data sources. PG&E will also extract and clean the data as needed. These steps are important pre-requisites to ensure an accurate and usable representation for the electrical and geographic mapping between elements including customer meters, distribution substations, transmission substations, and other region-specific data.

Examples of some of the sources of more granular data are:

- More granular demand data from distribution and transmission sources associated with region specific weather data on an hourly or more refined basis.
- Leverage monitoring and telecommunications technology being deployed at distribution substations to be a potential new source of data.
- The mapping of SmartMeters™ and customer enrollment data to the selected region to provide accurate information about bundled customer demand in particular regions.

2. Build Phase

The build phase leverages the data analysis and mapping activities of the previous phase to build a central data collection and analysis platform that collects, processes, and houses demand data used for the forecasting process. Furthermore, the build phase will also use the stored historical data to train the demand forecasting model.

PG&E information architects will build and implement the data repository by creating interfaces linking data sources to the repository, developing automated data loading and cleansing processes, and performing calculations to represent data in usable form. These steps will enable the transmission SCADA data, distribution SCADA data, SmartMeter™ data, bundled customer enrollment, and other relevant source to be collected within the repository. PG&E information architects and forecasting specialists will integrate these various sources of data in a meaningful way to represent electricity demand in the region and represent the amount of demand associated with bundled customers.

This representation of demand will be housed in the repository for the historical time period and will continue to accumulate on an on-going basis. The repository will also perform the calculations to adjust the effects of DR events that are called to reconcile the actual demand that would have occurred in the absence of those DR events. The repository will provide the data needed to calibrate the selected region demand to the bundled customer demand using SmartMeter™ data along with other existing sources of information for the selected region. The repository must also accurately track the movement of customers into and out-of bundled procurement for the selected region.

The repository built in this phase provides the key inputs for the demand forecast model, creating future forecasts, and calibrating the relationship between the selected region demand and bundled customer demand.

The build phase will configure and train the vendor provided forecast model used in the pilot phase.

3. Pilot Phase

The pilot phase aims to forecast demand for bundled customers in the selected region using more granular inputs, make adjustments as necessary, and compare results against the existing forecasting process. The final step of the pilot phase includes developing an implementation plan for the full-deployment of granular short-term demand forecasting for PG&E's entire service area.

During the Project, PG&E will continue using the existing top-down forecasting systems and processes to support short-term electricity procurement market activities. The limited scope of the Project to a specific region is to provide information on the forecasting approach for a possible implementation for the entire service area in the future.

The build phase of the project stores historical granular data into the repository and uses a portion of that data (i.e., two years) to train the forecasting model. The pilot phase will use the remaining set of historical weather and SCADA data (i.e., one year) as an input into the forecasting model to develop hourly demand.

Testing with the remaining set of historical data avoids biasing the results with the same inputs used to train the model. The resulting forecast will be compared to the actual demand for the same region and time period.

The output of the forecasting model is an overall estimate of demand, including bundled and unbundled customers, within the region selected for the pilot. This forecast will be adjusted to determine the bundled-only customer demand by using the historical SmartMeter™ and customer enrollment data.

A statistical analysis will be performed to compare the accuracy of the forecast from this pilot project to the accuracy of the existing forecasting process. The items to be compared are as follows:

- Variation between day-ahead forecasts.
- Variation between day-ahead forecasts and real-time forecasts.
- Variation between real-time forecast.

To test the new forecasting process described in this section, PG&E will simulate operations using historical data from the repository in batch mode, rather than continuously operating in real-time. This allows PG&E to lower Information Technology (IT) costs associated with near real-time data transfers and perform pilot phase testing for a year, without actually waiting a year for results.

The increased penetration of distributed solar photovoltaic (PV) and electric vehicles could impact the future accuracy of hourly demand forecasts. The implementation and standards for these are still evolving. As part of this project, PG&E proposes to engage in initial investigations and evaluation of the forecasting tools to assess the impacts of distributed PV and electric vehicles on future demand forecasting.

D. Projects Benefits

By conducting the Short-term Demand Forecasting Pilot Project, PG&E seeks to:

a) Determine whether more granular input data can improve the accuracy of the demand forecast.

b) Determine if the process can be scaled from a single region to the entire service area and what are the costs associated with the full scale deployment of a more granular forecast process.

During the pilot phase, the project will compare the difference in the accuracy of the forecasts produced in this Project to the current forecasting process, for the specific region.

This Project will estimate the benefits of improving the accuracy of the demand forecasts. At this time, such benefits are uncertain. Using a more granular approach to demand forecasting may result in the following operational benefits:

- Reduce PG&E's exposure to procuring energy in the more volatile real-time energy markets by procuring more energy the day-ahead energy markets.
- Reduce the amount of uncertainty of the load that is seen by the CAISO and potentially decrease the procurement of ancillary services to manage that uncertainty. The CAISO procures certain ancillary services to manage the forecast uncertainty of demand and supply.
- Increased system reliability by ensuring sufficient resources are matched and available to meet demand.
- Improved accounting for unaccounted for energy and associated costs.

E. Estimated Project Costs

1. Summary of Costs Included in Chapter

The additional costs needed for this demonstration Project are made of two major components: Energy Procurement costs and IT costs, which are described in the following sub-sections. Both components are estimated for each year and phase of the pilot period, and summarized in Table 4-1 below.

TABLE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
SHORT-TERM DEMAND FORECASTING SMART GRID PILOT PROJECT

Line No.	Items	2013	2014	2015	2016	Total
1	Energy Procurement Costs	$590,774	$493,853	$507,423	$521,501	$2,113,551
2	Information Technology Costs	1,984,587	6,677,357	1,666,788	1,706,698	12,035,430
3	Total	$2,575,361	$7,171,210	$2,174,211	$2,228,199	$14,148,981

2. Energy Procurement Costs

Energy Procurement's costs are divided into two parts: additional labor and model expenses. As to the additional labor expenses, PG&E estimates that two additional full-time employees are needed for the Project, a project manager and an analyst. The project manager will interface with IT and other groups in PG&E to fully understand the content of data sources, create formal data requests, and track and communicate project progress. The analyst will lead the analysis and formatting of data for forecasting, develop data from the repository into a useable format, perform the forecasting, and comparison of the results.

For modeling purposes, PG&E recommends using two forecast models. The first forecasting model will be used to test the more granular forecasting process, as discussed previously. The second model will be used to forecast the impact of distributed solar PV and electric vehicles on bundled customer demand forecasts. The costs for each model includes configuration costs for the analyze phase and annual subscription fees for analyze, build, and pilot phases of the Project. All Energy Procurement costs are expense items.

3. IT Costs

Information Technology support is required to analyze, design, install, test, approve, and implement systems that securely integrated to process the data into information that can be used to improve the forecasting models. The two areas of information management and cyber security are the key elements of the IT effort required for this Project. Over the course of the project an initial design of a full scale production deployment system will also be completed. The following section describes the two IT components driving project costs in more detail.

a. IT Information Management

Most of the IT effort associated with this Project is based on the collection, cleansing, transformation, and aggregation of data from many disparate systems into useful analytics. The Project builds upon data that is currently collected for demand forecasting, while significantly increasing the number of data points, volume of data, and also sources of data. Because of the large number of information exchanges, there is a corresponding increase in the complexity of the interactions between applications. To minimize that complexity, data will be aggregated together from all the systems into a central repository and structured for system consumption. The detailed level of effort associated with these information-centric functions is derived based on the following criteria:

- **Volume of Data**: In the pilot, additional sources of SCADA data from the transmission and distribution system, customer enrollment, SmartMeters™, and DR are all required as inputs to the forecasting process. PG&E estimates that data will be extracted from up to 10 internal systems to serve as inputs into proposed forecasting process in the pilot. Much of this data must be mapped, and aggregated before it can be used in the forecasting process. Three years of data from the identified sources will be loaded into the pilot repository as the initial representative set. Data will then be refreshed on a sub-daily basis from these sources and a rolling 5-year history of data will be collected into the repository. The pilot repository will be required to handle terabytes of data volume which will need to be procured to meet the needs of the system.

- **Frequency & Timeliness of the Data Transmissions**: This system will need to be capable of handling an increased volume and frequency of data given the requirement for more detailed data points available for collection. Obtaining this data from the various sources also entails creation of Application Programming Interfaces (API) or other data extraction and validation processes to ensure accurate, timely, reliable and complete transfer of data from the source systems into the central repository.
- **Data Quality**: Data that is extracted from existing systems needs to be monitored for accuracy. This happens by building algorithms and/or training people to correct inaccurate data streams, building interfaces that are able to detect when changes to the data occur, building APIs to connect to source systems and pull only relevant data changes into the pilot data repository, and building the appropriate data aggregation models that are capable of pulling the right amount of data at the appropriate level of detail.
- **Reporting and Analysis Needs for the New Information**: The millions of gathered data points must be provided in a manner that allows for ease of consumption and analysis. This requires building sophisticated data modeling and query techniques that allow the end users to manipulate the data in various formats. As part of this project, PG&E will utilize the concept of a "Data Concierge," which is

a specialized Information Architect who works with Energy Procurement personnel to gather and implement data into the forecasting process.

b. Cyber Security

As described in PG&E's Smart Grid Deployment Plan, effective cyber security controls and mechanisms are critical to the safe, reliable, and secure operation of Smart Grid technologies. There are seven key cyber security activities needed to maintain an acceptable level risk which translates primarily to labor applied at varying levels of effort depending on the risk of the Project. For this Project, the risk rating was determined to be "medium to low" which includes assessment and testing system interfaces across security boundaries and design of a security profile and scalable architecture. These system interfaces will need to be evaluated and tested to ensure robust security controls are in place to mitigate cross-system cyber security threats and risks. The hardware and software investment is limited to a secure file transfer system that transmits data securely across system boundaries. This applied security process and associated level of effort is designed to expose and discover the risks and mitigate them before they scale to full production.

4. Risk and Uncertainties Related to Estimated Costs

This Project has complexities in both IT and in business implementation, which may increase the cost of performing this pilot above PG&E's $14.1 million cost estimate. The complexities are:

- The data are stored on many different systems and in different formats make it difficult to extract and integrate the data to provide a representation of historical demand.
- There may be inconsistencies and gaps in the existing data that could increase the costs to integrate and aggregate data to be used as input for demand forecasting.
- PG&E may have underestimated the costs of acquiring, configuring, and training the forecasting models.

F. Conclusion

PG&E requests that the Commission fund the proposed Project to explore possible improvements in PG&E's short-term electric forecast process. PG&E also requests that the Commission adopt PG&E's capital and expense expenditure forecast presented in Section E of this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

SMART GRID CUSTOMER OUTREACH AND EDUCATION PILOT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
SMART GRID CUSTOMER OUTREACH AND EDUCATION PILOT

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
SMART GRID CUSTOMER OUTREACH AND EDUCATION PILOT

A. Introduction

1. Background

Pacific Gas and Electric Company's (PG&E) vision for the Smart Grid is to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration of advanced communications and control technologies to transform the operations of its electric network, from generation to the customer's premise.[1] PG&E's proposed Smart Grid approach addresses the following customer objectives, which were also defined in Senate Bill 17[2] and Decision 10-06-047:

- Empowering customers to directly participate in grid operations.
- Accommodating all electricity generation, storage, Energy Efficiency (EE), and Demand Response (DR) programs, including customer-owned and Distributed Generation (DG).

Customers must have the tools and knowledge to personally benefit from the Smart Grid in the ways most impactful to them as individuals, families and businesses. The scale of educating customers about the Smart Grid, given the large size and diverse demographic makeup of PG&E's customer service territory, is a large undertaking. Smart Grid education will build on existing education efforts related to SmartMeter™, time-of-use pricing and other time-varying pricing rates, EE, DR and others, and will provide a larger context of understanding about what the Smart Grid is, what it can do for the customers, and why it is relevant to customers.

PG&E proposes to pilot a targeted outreach strategy focused on specific geographic areas and groups of customers, including residential, business, multicultural or hard-to-reach customers, that are selected based on the relevance and potential impact of the pilot Smart Grid technologies being

[1] Appendix A, p. 4.

[2] Stats. 2009., Ch. 327.

piloted and potentially implemented system-wide. Through this proposed customer outreach pilot, PG&E will use a locally targeted approach to test customer response to integration of Smart Grid messaging with various energy education campaigns and will educate customers on the facts, benefits and costs associated with the implementation of Smart Grid technologies, including the pilot Smart Grid projects proposed in the Smart Grid Pilot Deployment Project under this application. As PG&E begins to pilot new Smart Grid technologies, it will engage with customers and use the opportunity to see which messages resonate with them, and then iterate accordingly to ensure it can successfully work with customers on an ongoing basis.[3]

Key Objectives of the Customer Outreach Pilot:

- Test new Smart Grid-specific messaging and customer outreach materials and gather customer input.
- Use customer feedback to determine how best to communicate factual and objective information on the Smart Grid to customers.
- Identify areas of potential customer question, concern or confusion related to Smart Grid pilot projects and technologies generally, and develop strategies to address these issues.
- Develop a scalable Smart Grid communication strategy that meets longer-term objectives of PG&E's Smart Grid deployment plan, including the customer outreach strategies identified in PG&E's Smart Grid Deployment Plan, and creates a foundation for customer understanding, knowledge and engagement in Smart Grid technologies.

These objectives are informed by the early-stage research PG&E conducted to understand customers' interest and initial perceptions of the Smart Grid.

PG&E plans to use 2013 as an initial trial year to test messaging. During the years of 2014-2016, PG&E plans to further test and refine targeted and early Smart Grid deployment outreach based on the locations of the pilot projects as well as the potential system-wide deployment of

[3] Smart Grid Deployment Plan filing, Chapter 8, p. 199.

Smart Grid technologies generally, to deliver the information that is most relevant to customers, and identify the factors that lead customers to request or require additional information.

2. Organization of the Remainder of This Chapter

- Section B – PG&E Smart Grid Outreach and Education Approach
- Section C – Proposed Geographically Targeted Outreach Pilot
- Section D – Outreach Costs Requested in This Chapter
- Section E – Conclusion

B. PG&E Smart Grid Outreach and Education Approach

Based on experience with the deployment of SmartMeter™ technology, as well as the rollout of time-varying pricing, PG&E has identified the critical need for a multi-touch approach that educates customers at multiple levels and through multiple communications channels about the energy management solutions and enabling technologies that reach their communities, including Smart Grid products and services prior to the large-scale implementation of these technologies. The proposed Smart Grid customer outreach pilot includes:

- A combination of messages through multiple activities and methods, aimed at establishing a baseline customer understanding of the Smart Grid.
- Communication of factual information about the Smart Grid technology pilots to customers, business and their communities.
- Determination of the Smart Grid facts, benefits, and costs that are most important and impactful for customers.
- Addressing customer questions, problems and concerns.

PG&E anticipates focusing customer communications on factual information about the Smart Grid as a whole, as well as in the context of the technology projects included in this application. For example, the Voltage and Reactive Power (Volt/VAR) Optimization project proposes to improve voltage control in areas with high penetrations of rooftop solar photovoltaic (PV) generation, using input from distribution-level devices along with SmartMeter™ voltage measurements. Customer education and awareness concepts could emphasize that the combination of SmartMeter™ technology and the Volt/VAR Optimization

System increase the amount of solar PV that can be safely and reliably interconnected in this specific part of PG&E's service territory.

As another example, the Smart Grid Line Sensor Technology project proposes to test, evaluate and pilot overhead line sensors on select distribution feeders with a high frequency of outages. The line sensors will pinpoint the outage/equipment damage location reducing the outage times these customers experience. Outreach concepts and targeted communication could emphasize such benefits as PG&E will be able to more quickly and efficiently restore service in their area through this Smart Grid technology, initially geographically-targeted in areas which have historically been subject to higher frequency of reliability issues.

In addition to providing factual information about the benefits of Smart Grid pilot project technologies, PG&E intends to identify obstacles that may lead to customer resistance or misunderstanding on Smart Grid technologies generally. Based on PG&E's experience with the implementation of SmartMeter™ technology, potential customer concerns and perceptions about the Smart Grid may include higher bills, privacy, security, and health impacts of Radio Frequency. To effectively communicate customer-facing Smart Grid technologies and projects generally, PG&E plans to create a foundational understanding of the Smart Grid and what its future deployment, including both benefits and costs, could yield for customers. Specifically, helping customers understand what the Smart Grid is and what it can enable. This will help to frame the conversation with customers as specific Smart Grid projects and benefits become available, and identify ways to engage with specific customer groups, such as multicultural or hard-to-reach customers.

C. Proposed Geographically Targeted Outreach Pilot

1. Proposed Pilot Methodology

In the first year of the geographically targeted customer awareness pilot, PG&E plans to develop and test its messaging and outreach approach prior to increasing the scope of efforts in 2014-2016. This multi-year pilot approach is intended to provide a foundation for large-scale implementation of outreach and education once the Smart Grid pilot technologies have been vetted and the outreach strategy tested and refined. The timing of the large-scale effort will be dependent in part on the full-scale implementation of Smart Grid technologies and partly based on the needs of customers for information about the Smart Grid. Any request for funding for both the large scale Smart Grid deployment and associated customer outreach will be included in a future General Rate Case or separate application[4] and will be guided by the outcome of the pilots in this application. The specific components of the proposed Smart Grid Customer Outreach and Education Pilot are explained further below.

2. Proposed Pilot Scope of Work

The Smart Grid Customer Education and Outreach Pilot is composed of Customer Research and Analysis, Customer Outreach, Organizational Readiness and Change Management and related staffing requirements. PG&E proposes the following scope of work to accomplish the objectives identified on page 5-2 of this testimony.

- **Customer Research** – PG&E plans to conduct additional customer research that builds on the initial PG&E-specific research findings explained in the Smart Grid Deployment Plan[5] to further develop and update Smart Grid messaging and positioning. Initial PG&E specific research identified two primary findings: (1) the Smart Grid is largely unknown to residential customers (but favorability increases with information); and (2) there is a high level of interest in the Smart Grid.

  These two findings reinforce the importance of conducting further research to build an understanding of customer education and awareness needs about the Smart Grid and the need for PG&E to adapt messaging based on customer feedback and experience. Through SmartMeter™ outreach, PG&E has learned the importance of ensuring customer-facing messages are simple, clear and easily understood. Message testing provides the forum to hear directly from customers, and ensure outreach is focused on their interests and concerns.

  To accomplish these goals, PG&E intends to conduct studies to gain understanding of customer perceptions of: (a) what the Smart Grid is;

---

[4] D.10-06-047, Ordering Paragraph 14.

[5] Appendix A, p. 202-204.

(b) how it can benefit them; and (c) what will motivate them to participate in Smart Grid related products, facilities and services. More specifically, this proposed research will include studies that address customer preference with regard to the amount and type of information customers will find relevant when considering Smart Grid education outreach, their desired method of communication delivery, motivations in participating or understanding more about Smart Grid benefits and barriers that could prevent customers from taking an interest in future Smart Grid products, facilities and services. Customer research findings will facilitate actionable developments in the structuring and positioning of future Smart Grid outreach and education activities.

PG&E plans to conduct ongoing tracking studies to gain insights into the impact of messaging and various tactics. This continued effort will help to understand and refine key findings related to the education needs and preferences by customer group or geographic location. PG&E plans to use this test-and-refine methodology to guide outreach efforts described below and optimize a plan for additional and more wide-scale Smart Grid outreach in the future.

- **Customer Outreach** – PG&E plans to develop messaging and outreach materials to be deployed with flexibility among key customer groups with identified educational needs, such as multicultural, hard-to-reach or Small and Medium-sized Businesses (SMB), as well as in areas where initial technology pilots will take place.

PG&E has found, through experience with the See Your Power and Power a Brighter Future outreach related to SmartMeter™ technology, that face-to-face interactions with customers provide an excellent vehicle for targeted customer engagement and interaction. Accordingly, PG&E's proposed approach to this pilot outreach focuses on similar activities, including mobile educational tours, local events, targeted direct mail, and community outreach facilitated by local government and third party organizations.

To provide ongoing support and resources for customers to further explore the benefits associated with Smart Grid, PG&E plans to develop online content and collateral as part of this pilot. Table 5-1 below provides a breakdown of the communications and outreach channels and activities that will be used in the outreach pilot project.

TABLE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
COMMUNICATIONS AND OUTREACH CHANNELS AND ACTIVITIES

Line No.	Outreach Channel	Description	Target audience
1	Third-Party Outreach	PG&E intends to leverage existing relationships and partner with stakeholder groups to communicate Smart Grid messaging as a means of engaging customers in further discussion about energy management and potential program participation.	Residential, Agricultural and SMB
2	Event and Local Outreach	PG&E plans to engage local audiences through a mobile tour experience that reaches targeted areas that are selected based on need and/or implementation of technology pilots. These events will provide a forum where PG&E can integrate complementary EE, DR, and DG messages and have proven to effectively reach groups of customers with identified education needs, such as multicultural or hard-to-reach customers.	Residential, Agricultural and SMB
3	Direct Outreach	Geographically targeted direct mail and email to build awareness of events, Smart Grid-related work and future benefits.	Residential
4	Online	Updates to pge.com with content related to Smart Grid technologies and associated benefits. Integrated with EE, DR and DG as appropriate.	All Customers

- **Change Management** – As PG&E begins to move from pilot to large scale implementation of Smart Grid education and outreach in 2016 and beyond, there will be a need to train and prepare all customer facing employees to respond to customer inquiries and requests for information. These efforts will include content development and implementation of internal training and education. Additionally, PG&E will use internal communications and develop online resources to ready the organization as a whole to respond appropriately and knowledgeably to customers. This was a key learning from the SmartMeter™ deployment, and PG&E's employees represent a critical touch point with customers, particularly around new technology deployments.

3. Pilot Benefits and Improvements

At the broadest level, the pilot will work to ensure that targeted customers better understand what the Smart Grid is and how it can affect and benefit them in various direct and indirect ways, including improved service and reliability, integration of more renewable resources into the power grid and less need for new power plants in the longer term. On a more personal level, customers can gain insight into their role in the Smart Grid and gain awareness of the specific tools and resources they can use to take advantage of capabilities and information enabled by Smart Grid technologies. This can increase the benefits received through the broader set of DR and EE programs offered by PG&E, and research will guide which programs are offered, when and how. Finally, customers will receive information to answer the questions and mitigate the concerns and/or perceptions they may have related to the implementation of the Smart Grid, such as privacy, security or access.

D. Outreach Costs Requested in This Chapter

1. Summary of Costs Included in Chapter

PG&E has based its cost estimate on projects and studies of similar scope and whenever possible, leveraged actual cost data for SmartMeter™ related outreach and education and related staffing requirements. While costs appear to be relatively constant over the period 2013-2016, the majority of work in earlier years is focused more heavily on research and development of communication and outreach messaging for testing purposes. Work and the associated costs in the later years (2015 and 2016) is more heavily weighted on outreach implementation and preparation for more widespread deployment efforts in 2017 and beyond.

TABLE 5-2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF CUSTOMER OUTREACH AND EDUCATION COSTS
($ IN THOUSANDS)

Line No.	Customer Outreach and Acquisition	2013	2014	2015	2016	Total Forecast (2013-2016)
1	Outreach Labor	$300	$300	$300	$300	$1,200
2	Organizational Change and Employee Training	–	–	–	500	500
3	Research and Analysis	310	250	260	100	920
4	Customer Impact and ES&S Comms	250	250	300	300	1,100
5	Communication and Outreach	2,015	2,190	2,265	2,190	8,660
6	Third-party outreach (stakeholder/community)	360	360	360	360	
7	Events and local outreach (mobile education tour, local events)	500	750	750	750	
8	Direct outreach (direct mail, email, booklets/ collateral)	900	900	900	900	
9	Online/social media	255	180	255	180	
10	Subtotal	$2,875	$2,990	$3,125	$3,390	$12,380
11	Non-Labor Escalation	$135	$219	$308	$357	$1,019
12	Labor Escalation	21	22	25	48	117
13	Subtotal	$156	$241	$333	$405	$1,136
14	Total	$3,031	$3,231	$3,458	$3,795	$13,516

Note: Total Costs Subject to Rounding.

E. Conclusion

The benefits of piloting customer outreach and awareness messaging related to the Smart Grid prior to widespread implementation include more efficient selection of tactics, and greater efficiency and impact on customer education and awareness of Smart Grid pilot projects and technologies generally due to enhanced understanding of customer needs and proven relevance of outreach and messaging. PG&E will work to refine and improve the effectiveness of Smart Grid-related outreach and messaging as it gains experience and gathers data from the targeted audiences in 2013-2016. PG&E will use the insights gained through the customer research and the targeted outreach and education approach described throughout this chapter to validate and refine its Smart Grid messaging and strategy. PG&E plans to use this test-and-refine methodology to guide outreach efforts and optimize a plan for additional and more wide-scale Smart Grid outreach in the future as needed and consistent with PG&E's Smart Grid Deployment Plan.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

RESULTS OF OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
RESULTS OF OPERATIONS

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
RESULTS OF OPERATIONS

A. Introduction

1. Scope and Purpose

The purpose of this chapter is to present the revenue requirements needed to support Pacific Gas and Electric Company's (PG&E) Smart Grid Pilot Deployment Project for 2013 through 2016. As discussed in Chapter 7, revenue requirement will be trued up to recover actual costs through a new balancing account. The revenue requirement establishing final cost recovery will be established based on a recorded revenue requirement calculation using the same Results of Operations (RO) assumptions presented here, updated as appropriate for authorized financial factors and tax parameters. This chapter supports the cost basis on which the Smart Grid Pilot Deployment Project rates are calculated for forecast purposes.

2. Summary of Proposal

PG&E's Smart Grid Pilot Deployment Project cost of service, as expressed in the revenue requirement, is calculated based on PG&E's planned capital expenditures and expenses. As a result of this methodology, PG&E shows the revenue requirements presented in Table 6-1 broken out by project.

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
2012-2015 REVENUE REQUIREMENT REQUEST
($ DOLLARS)

Line No.	Smart Grid Pilot Deployment Project	2013	2014	2015	2016	Total
1	Distribution Pilot	–	$609,117	$(3,592,920)	$14,470,882	$11,487,079
2	Short Term Demand Forecasting Pilot	$597,134	545,755	(3,071,725)	4,003,024	2,074,189
3	Technology Evaluation, Standards & Testing	2,331,295	3,246,868	3,262,707	2,828,678	11,669,547
4	Customer Outreach and Awareness	3,063,686	3,265,553	3,495,732	3,835,391	13,660,361
5	Total	$5,992,115	$7,667,293	$93,793	$25,137,974	$38,891,176

B. Operations and Maintenance Expenses

The Operations and Maintenance expense estimates for 2013 through 2016 include labor, materials, supplies, contracts, and other expenses related to implementing the Smart Grid Pilot Deployment Project. Chapters 2 through 5 provide the estimated amount of these expenses and describe the services provided. These expenses are estimated in nominal dollars. This is consistent with the method PG&E used in its 2011 General Rate Case (GRC) Application 09-12-020, filed December 21, 2009. All incremental PG&E labor includes standard burdens such as payroll taxes and direct benefits. Indirect employee benefits such as those associated with post-retirement, long-term disability, workers compensation and casualty insurance are excluded.

C. Capital-Related Inputs

The primary capital-related inputs to the cost of service calculation are presented in Chapters 2 through 4. Capital costs are grouped by the following classifications: (1) Information Technology (IT) Hardware; and (2) IT Software. These classifications have certain tax treatment as discussed in Section D.4.

D. Elements of the Results of Operation Calculation

The Smart Grid Pilot Deployment Project annual revenue requirement calculations show the revenues that PG&E needs to cover the incremental expenses. These calculations also include the revenues that PG&E needs to cover the capital-related costs associated with Smart Grid Pilot Deployment Project that have gone into service in 2013 through 2016.

In addition to the expenses described above, expense-related costs also include property, business and other taxes, which are based on the currently effective tax rates. PG&E applied a Franchise Fees and Uncollectible (FF&U) factor of 0.010675 (electric) to the revenue requirement. This FF&U factor was agreed upon in PG&E's 2011 GRC Settlement Agreement (D.11-05-018).

The various capital-related components of the RO calculation are discussed below.

1. Depreciation

Depreciation is included in the cost of service calculations as both depreciation expense and accumulated depreciation.

Depreciation expense is calculated using depreciation accrual rates based on the straight line, remaining life method in accordance with the Commission Standard Practice U-4, *Determination of Straight Line Remaining Life Depreciation Accruals*. Depreciation measures the loss of value in tangible assets that occurs as the assets are used up over time. Depreciation expense represents the amount of that value recognized in a given year for recovery of prior capital investment. It is through depreciation expense, net of salvage value, that a utility recovers its original capital investment through rates.

PG&E classified the capital additions by plant type, thereby assigning the appropriate depreciation rate and service life. These classifications include: (1) IT Hardware; and (2) IT Software. For each classification, PG&E estimates depreciation expense by multiplying the weighted average plant in service by the corresponding book depreciation rates. PG&E estimates the depreciation expense using the depreciation rate schedule as determined in the 2011 GRC Settlement.[1] By using the depreciation schedules, Table 6-2 summarizes the depreciable lives and depreciation rates that PG&E proposes for its Smart Grid Pilot Deployment Project assets.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
BOOK DEPRECIATION ASSUMPTIONS

Line No.	Asset	Life (Years)	Rate (%)
1	IT Hardware	5	19.51
2	IT Software	5	19.81
3	Substation Relays	34	2.92
4	OH Conductor and Devices	22	4.64
5	Electric General Lab Equip.	12	8.09
6	Common Com. Equip.	7	14.28

Accumulated depreciation is calculated by adding estimated depreciation expense and net salvage value to the prior year's end-of-year reserve balance and subtracting the forecast asset retirements.

[1] 2011 PG&E GRC Rate Case, Settlement approved in Decision 11-05-018.

2. Rate Base

The elements of rate base included for Smart Grid Pilot Deployment Project costs are: utility plant in service, plus working capital, less deferred taxes, and less accumulated depreciation. Utility plant in service consists of the accumulated undepreciated investment in plant and equipment that is used and useful in rendering the services that are required by the Smart Grid Pilot Deployment Project. In developing the associated rate base, certain deductions are made. A deduction is made for the accumulated deferred taxes associated with these assets. These deferred taxes result from following the Modified Accelerated Cost Recovery System (MACRS) tax depreciation method for Federal Income Tax (FIT) purposes. Due to the timing differences that result from the use of this tax depreciation method, taxes that have been paid for by the customer are not paid to the Internal Revenue Service until a later date. Finally, plant is reduced by the amount of depreciation reserve (i.e., the accumulated depreciation already taken in prior years).

3. Rate of Return

PG&E multiplies the currently adopted composite Rate of Return (ROR) of 8.79 percent by the Smart Grid Pilot Deployment Project average rate base for each year to calculate the return on rate base. This calculation uses the ROR and capital ratios adopted in PG&E's 2008 Cost of Capital (COC) decision (D.07-12-049).[2] Subsequent calculations of recorded revenue requirements for entry into the Smart Grid Pilot Deployment Project Balancing Account will incorporate the latest authorized ROR for capital revenue requirements.

4. Income Tax Depreciation Assumptions

This section describes the assumptions and calculations used in the revenue requirements calculations to estimate income tax depreciation. PG&E estimates California Corporation Franchise Taxes and FITs on net operating income before income taxes. FIT expense is the product of the

[2] Decisions 08-05-035 and 09-09-016 maintained the 2008 COC levels for 2009 and 2010, respectively. The 2008 COC levels remain in place for 2011 as the Annual Cost of Capital Adjustment Mechanism (ACCAM) trigger was not met.

currently effective corporate income tax rate (35 percent) and federal taxable income. Likewise, state income tax expense is the product of the statutory rate (8.84 percent) and the state taxable income.

FITs are computed on a normalized basis. This allows PG&E to recognize the timing differences between book and federal tax depreciation. This difference multiplied by the federal tax rate is called deferred FITs, and is included as a credit to rate base.

State income taxes are calculated on a flow-through basis. Therefore, the customers receive an immediate benefit from the use of accelerated state tax depreciation. There is no associated rate base deduction for deferred state taxes.

PG&E followed MACRS and Asset Depreciation Range (ADR)[3] guidelines for classifying Smart Grid Pilot Deployment Project capital additions and calculating federal and state tax depreciation. All acquired software is capitalized for tax depreciation, and therefore generates tax depreciation and deferred tax expense when it is booked as an expense.[4] Section 167(f)[5] of the Internal Revenue Code (IRC) requires taxpayers to capitalize and depreciate certain software acquired in the open market. Section 174 of the IRC provides that some portion of the cost of certain self-developed software may be deducted currently. As in the 2011 GRC, PG&E has used normalized tax accounting treatment for amounts that are capitalized under Section 167(f) and flow-through tax accounting treatment for the amounts that are deductible under Section 174.

Bonus tax depreciation is being applied to qualifying capital in 2012.[6] Table 6-3 summarizes the federal and state tax depreciation methods used in the RO calculations. Subsequent calculations of capital-related revenue

[3] Uses Sum of Years Digits (SYD) method.

[4] Software exceeding a $1 million threshold is capitalized for book depreciation in accordance with the 2011 GRC settlement Decision 11-05-018.

[5] The Omnibus Budget Reconciliation Act of 1993 (Pub. L. 103-66) added Section 167(f) to the IRC, effective for capitalized software purchased after August 10, 1993.

[6] On December 17, 2010, President Obama signed the Tax Relief Act. This Act provides for 100 percent bonus depreciation in 2011 and 50 percent bonus depreciation in 2012 for qualifying property.

requirements for entry into the Smart Grid Pilot Deployment Project Balancing Account will incorporate the latest authorized or best available tax accounting parameters.

TABLE 6-3
PACIFIC GAS AND ELECTRIC COMPANY
TAX ASSUMPTIONS

Line No.	Asset	Federal Tax Method	State Tax Method
1	IT Hardware	5-Year MACRS	6-Year ADR SYD
2	Internally Developed Software	Expense	Expense
3	Substation Relays	10-Year MACRS	30-Year ADR SYD
4	OH Conductor and Devices	10-Year MACRS	30-Year ADR SYD
5	Electric General Lab Equip.	7-Year MACRS	12-Year ADR SYD
6	Common Com. Equip.	7-Year MACRS	10-Year ADR SYD

E. Conclusion and Results of Operations

The capital expenditures and operating expenses described above and PG&E's 2011 adopted COC are used to determine the amount of revenue needed from customers to recover the costs of the Smart Grid Pilot Deployment Project. This amount of revenue is known as the revenue requirement or cost of service. PG&E's revenue requirement request is based on the 2008 COC approved in Decision 07-12-049 that has subsequently been maintained in 2009 and 2010 by Decisions 08-05-035 and 09-10-016, respectively, as well as in 2011, as the ACCAM trigger was not met.

For capital expenditures, the revenue requirement is calculated to recover the investment through depreciation; the return on investment through the application of the COC (ROR) to the rate base; income taxes associated with the return on equity and with the difference in timing of costs between book and tax calculations; and property taxes on the unrecovered investment (net plant).

Franchise fees and uncollectible expenses are added to the combined capital-related and expense-related revenue requirement. The factors used for this calculation are based on the factors applied in PG&E's 2011 GRC Settlement Decision 11-05-018. Details of the revenue requirement calculations are located in the Workpapers Supporting Chapter 6.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST RECOVERY PROPOSAL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST RECOVERY PROPOSAL

TABLE OF CONTENTS

SB_GT&S_0304089

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
COST RECOVERY PROPOSAL

A. Introduction

1. Background

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E) proposal for cost recovery of capital and operating expenses required to advance the modernization of PG&E's electric grid consistent with the policy of the state of California, as described in Senate Bill 17[1] and PG&E's Smart Grid Deployment Plan filed with the California Public Utilities Commission (CPUC or Commission) on June 30, 2011.[2]

2. Purpose

In this application, PG&E requests approval for cost recovery of forecast costs for the Smart Grid Pilot Deployment Project for the period 2013 through 2016. For ratemaking purposes, PG&E has assumed the program will begin in 2013 with a Commission decision by the end of 2012. If the decision is delayed, the revenue requirement calculations may need to be adjusted to match the timing of the actual work. If such a delay occurs, PG&E will file an advice letter with revised revenue requirements.

As described in Decision 10-06-047, the Commission ordered that PG&E "shall seek approval of Smart Grid investments either through an application and/or through General Rate Cases."[3] Cost recovery and associated revenue requirements will be addressed in this application because PG&E will not have sufficient time to incorporate the Commission's Final Decision on the Smart Grid Deployment Plan into its Test Year 2014 General Rate Case (GRC). Due to the expected timing of the Commission's Final Decision regarding the Smart Grid Deployment Plan and PG&E's

---

[1] 2009 Padilla.

[2] A.11-06-029.

[3] D.10-06-047, Ordering Paragraph 14.

2014 GRC,[4] PG&E believes it must seek approval to begin work on six of its 21 Smart Grid projects now to purse the potential benefits to customers or risk a significant delay in realizing the potential customer benefits.

3. Cost Recovery Proposal

PG&E proposes the following ratemaking treatment for the Smart Grid Pilot Deployment Project costs:

- Rates will be set initially to recover forecast costs, with true-up to actual costs achieved through a proposed new Smart Grid Pilot Deployment Project Balancing Account (SGPDPBA).
- Electric revenue requirements reflecting the cost forecast for the project will be revised annually through the Annual Electric True-Up (AET), or as otherwise ordered by the Commission, to include the forecast revenue requirement for the year and an adjustment for the difference between the forecast and recorded revenue requirement.
- Cost recovery will occur through the Distribution Revenue Adjustment Mechanism (DRAM) and will be consolidated with the AET. Assuming a decision in this proceeding before the 2013 AET, rates set to recover the 2013 revenue requirements will be set in the 2013 AET advice letter, or as otherwise authorized by the Commission. Rates set to recover the subsequent years' revenue requirement will set in the applicable AET advice letters, or as otherwise authorized by the Commission.

4. Organization of the Chapter

The remainder of this chapter is organized as follows:

- Section B – Summary of Costs
- Section C – Cost Recovery Proposal
- Section D – Conclusion

[4] The GRC Plan for the 2014 Test Year General Rate calls for PG&E to file its Notice of Intent by August 1, 2012. The Final Decision on the Smart Grid Deployment Plan is not expected until July 1, 2012.

B. Summary of Costs

1. Summary of Costs

PG&E requests approval to recover approximately $108.9 million in total costs expected to be incurred from 2013 through 2016, to implement and operate the Smart Grid Pilot Deployment Project. These costs include the incremental capital expenditures and Operations and Maintenance (O&M) expenses related to analyzing, testing, and piloting new systems and technologies. The total incremental costs are show in Table 7-1 and described in detail in Chapters 2 through 5 of the testimony.

TABLE 7-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF SMART GRID PILOT DEPLOYMENT PROJECT TOTAL COSTS
($ IN THOUSANDS)

Line No.	Project	2013	2014	2015	2016	Total
1	Smart Grid Line Sensors	$2,551	$8,681	$3,023	$2,652	$16,908
2	Volt/VAR Optimization	3,856	14,944	10,281	9,747	38,828
3	Detect & Locate Faults	1,733	8,224	1,547	1,506	13,009
4	Technology Evaluation Standards & Testing	2,306	3,587	3,585	2,973	12,451
5	Short Term Demand Forecasting	2,575	7,171	2,174	2,228	14,149
6	Customer Outreach & Awareness	3,031	3,231	3,458	3,795	13,515
7	Total	$16,053	$45,838	$24,068	$22,901	$108,860

The total incremental O&M expenses of $31.8 million are shown in Table 7-2 and described in detail in Chapters 2 through 5 of this testimony.

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF SMART GRID PILOT DEPLOYMENT PROJECT OPERATIONS AND MAINTENANCE EXPENSES
($ IN THOUSANDS)

Line No.	Project	2013	2014	2015	2016	Total
1	Smart Grid Line Sensors	–	$199	$641	$721	$1,561
2	Volt/VAR Optimization	–	298	925	1,012	2,236
3	Detect & Locate Faults	–	105	253	267	625
4	Technology Evaluation Standards & Testing	$2,306	3,212	3,160	2,598	11,276
5	Short Term Demand Forecasting	591	540	733	749	2,613
6	Customer Outreach & Awareness	3,031	3,231	3,458	3,795	13,515
7	Total	$5,928	$7,586	$9,170	$9,142	$31,826

The total incremental capital expenditures of $77.0 million are shown in Table 7-3 and described in detail in Chapters 2 through 4 of this testimony.

TABLE 7-3
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF SMART GRID PILOT DEPLOYMENT PROJECT
CAPITAL EXPENDITURES
($ IN THOUSANDS)

Line No.	Project	2013	2014	2015	2016	Total
1	Smart Grid Line Sensors	$2,551	$8,483	$2,382	$1,931	$15,347
2	Volt/VAR Optimization	3,856	14,645	9,356	8,735	36,592
3	Detect & Locate Faults	1,733	8,119	1,294	1,239	12,384
4	Technology Evaluation Standards & Testing	–	375	425	375	1,175
5	Short Term Demand Forecasting	1,985	6,631	1,442	1,479	11,536
6	Total	$10,125	$38,253	$14,898	$13,759	$77,034

C. Cost Recovery Proposal

PG&E is seeking authorization to proceed with the Smart Grid Pilot Deployment Project and approval to recover PG&E's revenue requirements, which is calculated based on forecast capital expenditures and O&M expenses. To begin this deployment, PG&E requests that the Commission establish rates to begin recovery of the project in 2013.

PG&E proposes that initial rates for the project be set based on the forecast of costs and that these costs be included in the total electricdistribution rates charged to customers. Although initial rates would be set based on this forecast, PG&E proposes that customers ultimately pay therevenue requirements of the project based on actual costs. PG&E proposes to create a new regulatory balancing account (SGPDPBA) to track the difference between the revenue requirements based on actual costs compared to the forecast revenue requirements. Forecast revenue requirements will be included in the DRAM for recovery.

PG&E is requesting approval to recover its forecast revenue requirement. If the Commission approves this application, PG&E will file an advice letter for approval of the preliminary statement for SGPDPBA and to include in rates the forecast revenue requirement for all project costs for 2013. The total revenue requirements of $38.9 million are shown in Table 6-1 and described in detail in Chapter 6. PG&E will recover the adopted forecast of revenue requirements in the SGPDPBA in electric rates as part of the AET advice letter, or as otherwise authorized by the Commission.

1. The Smart Grid Pilot Deployment Project Cost Recovery

a. Monthly Calculation and Balancing Account Entries

For purposes of the Smart Grid Pilot Deployment Project cost recovery, PG&E will record balancing account entries on a monthly basis. Upon approval of this application, each month from January 2013 through December 2016, PG&E will record the actual electric revenue requirement in the SGPDPBA.

1. Capital-related revenue requirements (debit), calculated on recorded plant additions.
2. Recorded O&M costs (debit), calculated on recorded expenses.
3. One-twelfth of the annual revenue requirement (credit) that was included in the DRAM base revenue amount, which is the forecast revenue requirement approved in this proceeding.
4. Interest on the average balance in the account.

At the end of the year the balance in the account would be transferred to the DRAM account. The revenue requirements recorded to DRAM will be recovered in distribution rates in the same manner as other distribution revenue, and will be revised annually in the AET, or as otherwise authorized by the Commission.

b. Cost Recovery if There Are Scope or Schedule Changes

The total costs forecast for the Smart Grid Pilot Deployment Project was used to develop the revenue requirements. PG&E requests that the Commission find that the costs and associated revenue requirements be reasonable. If the Commission's final decision modifies or expands the scope of the project, PG&E should be authorized to modify its revenue requirement forecast due to the expanded or modified scope. If the decision is delayed, the revenue requirement calculations may need to be adjusted to match the timing of the actual work. If such a delay occurs, PG&E will file an advice letter with revised revenue requirements for recovery through the AET.

2. Relationship to the General Rate Case

PG&E will file its next GRC in 2012 for rates recovering base costs in 2014 through 2016. The GRC forecast will not include costs associated with the Smart Grid Pilot Deployment Project. All incremental costs for the period 2013 through 2016 will be dealt with in this application, including all capital-related and maintenance costs. In this way, costs will not be double counted and all costs can be examined together in this proceeding. PG&E will continue to record and recover the revenue requirements (capital-related and ongoing O&M expenses) in the SGPDPBA until the subsequent GRC (currently projected for 2017).

PG&E proposes to consolidate its capital-related revenue requirements in its 2017 GRC. To the extent that the 2017 GRC cycle is delayed, PG&E proposes to file an Advice Letter to determine the appropriate capital-related revenue requirements. Detailed results shall be included in the advice letter that implements rates for 2017. The revenue requirements shall be recovered in electric rates in the AET for that year until the next GRC cycle.

3. Cost Reasonableness

PG&E requests that the Commission find the project costs to be reasonable. PG&E's forecast costs for the initiatives are based on extensive analysis. If PG&E completes the work at a lower cost than authorized, the reduction in revenue requirement will be credited to customers. Therefore, PG&E requests that the CPUC review the process and the cost estimates presented in this application, and find the forecast costs reasonable.

D. Conclusion

PG&E is requesting cost recovery for the Smart Grid Pilot Deployment Project costs incurred in the years 2013-2016 through the creation of a new electric balancing account (SGPDPBA). Entries into this balancing account would reflect the revenue requirement based on actual costs incurred. PG&E will recover its authorized revenue requirements and the year-end balance recorded in the SGPDPBA through the electric distribution rates set in the AET advice letters, or as otherwise authorized by the Commission. A full review of forecast costs will take place as part of this application process, and once these forecasts have been reviewed and adopted, no further reasonableness review should occur.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KEVIN J. DASSO

Q 1 Please state your name and business address.

A 1 My name is Kevin J. Dasso, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the senior director of the Smart Grid And Technology Integration Department. In this position, I am responsible for developing PG&E's Smart Grid investment plan and business strategy, managing the utility-wide portfolio of Smart Grid projects, overseeing PG&E's participation in critical Smart Grid standards activities and directing the preparation and support of Smart Grid related regulatory filings at the California Public Utilities Commission and the Federal Energy Regulatory Commission. I am also responsible for managing PG&E's technology laboratory and research organization.

I joined PG&E in 1981 and have held various positions in transmission and distribution planning, engineering, operations, maintenance and construction. I have been in my current position since August 2010.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in electric engineering from Iowa State University, in 1981, and a master of science degree in electrical engineering from Santa Clara University, in 1991. I am a registered professional electrical engineer in California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project:

- Chapter 1, "Smart Grid Pilot Deployment Project Policy."
- Chapter 3, "Technology Evaluation, Standards and Testing."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TERESA J. HOGLUND

Q 1 Please state your name and business address.

A 1 My name is Teresa J. Hoglund, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the director of Revenue Requirements and Analysis, which is a subsection of the Analysis and Rates Department and Rates and Regulation organization. I oversee work related to revenue requirement modeling for rate cases, near and long-term revenue requirement and rate forecasting, and economic forecasting.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of business administration degree with an accounting concentration from the Pacific Lutheran University in 1983. After my undergraduate studies, I worked in the Tacoma office of Ernst & Whinney as a consultant in the Tacoma Telecommunications Practice. I received a Certified Public Accountant certificate in the state of Washington in 1986. I moved to the state of California in 1987, where I joined CPNational/Alltel as manager of Cost Separations and Settlements. At CPNational/Alltel, over the next five years, I held various positions, including Western Region budget director, Western Region controller and Southwest Region controller.

In 1992, I joined PG&E as a senior analyst in the Plant and Depreciation Accounting group within the Capital Accounting Department. Subsequently, I held the position of the plant and depreciation manager. In 1995, I moved to the Corporate Accounting Department and held various positions or combinations of such positions over nine years including energy accounting manager, technical accounting manager, and external financial reporting manager.

In 2004, I left PG&E for personal reasons. In 2009, I returned to PG&E as a senior regulatory specialist in the Analysis and Rates Department. In 2010, I was promoted to manager of Regulatory Analysis and Forecasting, which is a group within the Analysis and Rates Department. I did governance work related to balancing accounts and monthly revenue requirement and rate forecasting. In 2011, I moved into my current position of director or Revenue Requirements and Analysis.

I have sponsored testimony before the California Public Utilities Commission (CPUC) for PG&E's recovery of Expenditures in 1997 and 1998 to Enhance Transmission and Distribution System Safety and Reliability Pursuant to Section 368(e) (A.99-03-039) and 2009 Market Redesign and Technology Upgrade (A.10-02-012).

I am also sponsoring cost recovery testimony in various CPUC proceedings, including PG&E's 2011 General Rate Case – Phase 3 (A.10-03-014), Default Residential Rate Programs (A.10-08-005), 2010 Market Redesign and Technology Upgrade (A.11-02-011), and Modifications to its SmartMeter™ Program (A.11-03-014).

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project:

- Chapter 7, "Cost Recovery Proposal."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NIELSON D. JONES

Q 1 Please state your name and business address.

A 1 My name is Nielson D. Jones, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal regulatory specialist in the Revenue Forecasting and Analysis section of the Analysis and Rates Department, where I am responsible for producing and supervising the preparation of revenue requirement models, and developing related testimony.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in nuclear and power engineering from the University of Cincinnati in 1985. I received a master of business administration degree from Golden Gate University in 1995. From 1985 to 1987, I worked as an engineer for Westinghouse Electric Corporation.

I joined PG&E in 1987 as an engineer in the Nuclear Power Generation Department. My responsibilities included nuclear fuel utilization analysis and reactor physics calculations. I was promoted in 1995 to supervisor, responsible for fuel and core technical analysis. In 1997, I was promoted to acting director of Nuclear Technical Services. My responsibilities included managing technical projects and programs supporting the Diablo Canyon Power Plant.

In late 1998, I left PG&E to join Altran Corporation, a management and engineering consulting company. As a senior consultant, I supported utilities throughout the United States on projects such as Y2K auditing, plant licensing review and probabilistic reliability studies.

I rejoined PG&E as a senior rates analyst in late 2000 and was promoted to the position of team lead of the Operations and Maintenance (O&M) expense group in August 2003. In this position, I was the working cash expert witness in the 2003 and 2007 General Rate Cases (GRC) as well as the O&M expense witness in Federal Energy Regulatory Commission filings. In June 2006, I became the supervisor of the results of operations group. In this position, I continued to be the PG&E expert witness for working cash in addition to being an expert witness for revenue requirement calculations and being a case manager for the cost of capital regulatory filing. In October 2010, I was promoted to my current position, principal regulatory specialist. In this position, I continue to be focused on the production of revenue requirement calculations for regulatory filings. Most recently, I was the revenue requirement witness in PG&E's SmartMeter™ Program Upgrade filing (A.07-12-009), the 2009 Rate Design Window filing (A.09-09-022), the 2009 Nuclear Decommissioning Cost Triennial Proceeding filing (A.09-04-007), the 2011 GRC Phase 1 and 3 filings (A.09-12-020 and A.10-03-014), the Market Redesign and Technology Upgrade filings (A.10-02-012 and A.11-02-011), the Modifications to the SmartMeter™ Program filing (A.11-03-014), the 2011 Catastrophic Event Memorandum Account filing (A.11-09-014), and the Pipeline Safety Enhancement Plan filing (A.11-02-019).

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project:

- Chapter 6, "Results of Operations."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAIDIPYA J. PATWA

Q 1 Please state your name and business address.

A 1 My name is Daidipya J. Patwa, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal within the Integrated Resource Planning department of PG&E's Energy Procurement organization. I am responsible for developing and supporting analysis, planning, and strategy related to resource planning and integration of renewables. I joined PG&E in 2009 and have held positions in energy efficiency and energy procurement.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in computer engineering from the University of Delaware in 2002, a masters degree in electrical engineering from the University of Delaware in 2008, and a masters degree in business administration from the Anderson School of Management at the University of California, Los Angeles, California in 2010. Prior to my employment with PG&E, I worked in product development at W.L. Gore & Associates.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project:

- Chapter 4, "Short-Term Demand Forecasting Smart Grid Pilot Project."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DANIEL J. PEARSON

Q 1 Please state your name and business address.

A 1 My name is Daniel J. Pearson, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a manager in the Smart Grid Technology and Integration organization within Engineering and Operations. My current responsibilities are focused on PG&E's Smart Grid Strategy.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in electrical engineering from Oregon State University, Corvallis, Oregon in 1981. I am a registered professional engineer in the state of California and a member of the Institute of Electronic and Electrical Engineers.

I began my employment as an engineer with PG&E in 1981. I have worked in both the divisions and in corporate headquarters, managing electric distribution engineering personnel, as well as performing capital and expense-related electric transmission and distribution engineering analyses. In 1996, I was the Distribution Customer Services project manager on the December Storm Hearings, and from 1993 through 2004 have been the Distribution Customer Services lead for PG&E's reliability and capacity programs. I also served as the witness in the following filings: 1999 General Rate Case witness for Electric Distribution Capital, 2009 Distribution Reliability Improvement Project, and 2011 General Rate Case witness for Electric Distribution Capacity Program.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project Filing:

- Chapter 2, "Smart Grid Distribution Pilot Projects."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVEN E. PROPPER

Q 1 Please state your name and business address.

A 1 My name is Steven E. Propper, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a program marketing manager for the SmartMeter™ program in our Solutions Marketing group. I am responsible for customer outreach and education campaigns as they pertain to the SmartMeter™ program. I am also responsible for determining how SmartMeter™ related education and marketing should evolve beyond the current deployment of meters underway and its intersection with other customer-facing programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of arts degree in economics from the George Washington University, and a master of business administration (M.B.A.) degree from INSEAD. I focused on both marketing and energy-related initiatives during my M.B.A., winning the 2010 INSEAD-Nokia Marketing Competition and ranking finalist in the 2009 Vestas Wind Energy Innovation Competition. Before my M.B.A., one of my major marketing communications projects was with an early stage Smart Grid technology company.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Smart Grid Pilot Deployment Project:

- Chapter 5, "Smart Grid Customer Outreach and Education Pilot."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.