PACIFIC GAS AND ELECTRIC COMPANY

SMART GRID ANNUAL REPORT – 2017

Date for Submission: September 29, 2017

SMART GRID TECHNOLOGIES

ORDER INSTITUTING RULEMAKING 08-12-009

CALIFORNIA PUBLIC UTILITIES COMMISSION

Contents

1. Smart Grid Annual Report Executive Summary 2
2. PG&E’s Smart Grid Deployment Plan and Project Updates 10
   2.1. Summary of Updates to PG&E’s Smart Grid Deployment Plan 11
   2.2. Summary of Benefits for Select Projects 11
   2.3. Smart Grid Project Updates 14
   2.4. Customer Engagement and Empowerment Projects 14
      2.4.1. Demand Response Projects 15
      2.4.2. Electric Vehicle Integration Projects 18
      2.4.3. SmartMeter™ Enabled Tool Projects 21
      2.4.4. Emerging Customer Side Technology Projects 31
   2.5. Distribution Automation and Reliability Projects 32
   2.6. Transmission Automation and Reliability Projects 37
   2.7. Asset Management and Operational Efficiency Projects 40
   2.8. Security (Physical and Cyber) Projects 41
   2.9. Integrated and Cross-Cutting Systems Projects 43
   2.10. Customer Roadmap 49
   2.11. Overview of Customer Engagement Plan 51
   2.12. Smart Grid Engagement by Initiative Area 52
   2.13. Key Risks Overview 54
   2.14. Key Risks and Actions Taken to Address Them 54
      2.14.1. Managing Cyber Security Risk Through Control Baseline 55
   2.15. PG&E’s Compliance With NERC Security Rules and Other Security Guidelines and Standards as Identified by NIST and Adopted by FERC 56
   2.16. Key Risks Conclusion 57
   3. Smart Grid Metrics and Goals 59
   3.1. Customer/Advanced Metering Infrastructure Metrics 59
   3.2. Plug-In Electric Vehicle (PEV) Metric 65
   3.3. Energy Storage Metric 65
   3.4. Grid Operations Metrics 66
4. Conclusion 73
5. Appendix 75

CHAPTER 1

SMART GRID ANNUAL REPORT

EXECUTIVE SUMMARY

1. Smart Grid Annual Report Executive Summary

Throughout the reporting period of July 2016 to June 2017, Pacific Gas and Electric Company (PG&E or the Company or the Utility) continued to build capabilities to deliver on its grid vision. PG&E introduced this vision in 2014, aiding in integrating Distributed Energy Resources (DER). This vision integrates new energy devices and technologies with the grid and allows their owners to realize greater value from their energy technology investments—rooftop solar, electric vehicles (EV), energy storage, Demand Response (DR) technologies, etc.—by virtue of their grid connectivity through an integrated platform. PG&E plays a critical role in delivering this interconnected and integrated platform that will define tomorrow's energy landscape for California. Innovative programs and plans help PG&E achieve the vision while also maintaining a safe and reliable grid. These include:

- The Electric Program Investment Charge (EPIC), which covers technology demonstration of pre-commercialized technologies. These projects involve a number of PG&E's organizations, from Asset Management and Information Technology (IT) to Customer Care and Energy Supply, spanning multiple departments from planning to operations. The goal of these demonstrations include learning key lessons about the applicability of new-and-novel uses of technology to deliver safe, reliable, affordable electric service, understanding how to better integrate DERs and enable new customer offerings, and exploring new uses of existing technology to help manage the evolving grid. EPIC demonstrations aid in identifying key requirements, implementation challenges, and benefit-cost details to inform future deployment. EPIC projects support the creation of new and valuable Intellectual Property (IP). This IP can lead to improved products and services that help improve the operations of the electricity grid by reducing operating expenses and/or potentially generate alternative forms of incremental revenue that can reduce customer costs.
- The California Energy Systems for the 21st Century (CES-21) Program focuses on early stage technology research. This public-private collaborative effort between the three California investor owned utilities (IOU) and Lawrence Livermore National Lab

(LLNL) focuses on how sophisticated modeling can enhance decision making for cybersecurity and resource planning.

- PG&E's Distribution Resources Plan (DRP) filing, which supports California's Clean Energy Vision, advocates for grid modernization, develops new analytics to estimate the existing and projected hosting capacity to accommodate anticipated DER growth at distribution feeder-levels, and develops methodology on how to quantify locational net benefits of DERs. It also proposes various DER field demonstration projects to test DERs abilities to safely, reliably and consistently provide distribution services as non-wires alternatives for the Utility.
- The Smart Grid Pilot Program, which tested and piloted four smart grid technologies: Volt Var Optimization (VVO), Line Sensors, Fault Detection and Location, and improved methods for Short Term Demand Forecasting. The pilots for these Smart Grid Technologies completed during the reporting period and lessons learned are informing further technology assessments and full-scale deployments.

DER growth continues in PG&E's service territory. A snapshot of potential projections for this territory include:

- 124,000 EVs growing to over 200,000 by 2020 – PG&E customers now drive 1 in every 5 EVs in the United States (U.S.).
- ~312,000 solar rooftop photovoltaic (PV) systems growing to over 600,000 by 2020.
- Continued growth in energy storage, including 580 mandated megawatts (MW) contracted by 2020.

Growth in DERs can be a great benefit to customers, though it also introduces unique challenges in managing the grid, such as those related to two-way power flow, voltage and power quality issues, as well as supply intermittency. Increased utilization of new grid technologies can help PG&E to manage the additional complexity that DERs introduce to operating the grid, increasing the amount of information available for grid operations, allowing utilities better oversight and eventual control of DERs.

Update – PG&E's Distribution Resources Plan

On July 1, 2015, PG&E filed its proposed electric DRP. PG&E noted the transformation of the electricity grid must ensure that electricity remains affordable for the millions of utility customers; at the same time, the future transformed grid will need to recognize the differentiated needs of customers and their flexibility to choose from various services. Below are some notable 2017 highlights:

- PG&E, in collaboration with other California utilities, the CPUC and external non-utility stakeholders, continues to work on developing a process for how the distribution planning process should incorporate DERs. In February, the CPUC issued a ruling that seeks the development of a process for incorporating DER forecasts and assumptions into the DRP. In August, a subsequent ruling requests the Energy Division and the California Energy Commission (CEC) to develop DER forecasting, growth scenarios, and disaggregation methodologies, taking into consideration the coordination with other statewide planning and forecasting processes, such as the CPUC's Integrated Resource Plan (IRP) process, the CEC's Integrated Energy Policy Report, and the California Independent System Operator's (CAISO) Transmission Planning Process. The California utilities will work with the CPUC Staff through workshops and comments to share the incorporation of DERs in the distribution planning process.
- PG&E provided recommendations on the CPUC's grid modernization white paper and Distribution Investment Deferral Framework (DIDF) Staff Proposal. In May, the CPUC issued a ruling requiring stakeholder responses to questions posed in Energy Division's white paper on grid modernization. The white paper is aimed at informing the development of a CPUC framework to evaluate grid-modernization investments.
  A workshop took place and comments were submitted by stakeholders in June. Also in June, the CPUC issued a proposed DIDF, which aims to establish a future process for identifying candidate distribution deferral opportunities for DERs as part of the annual distribution planning process. PG&E provided comments on the DIDF proposal jointly with utilities, offering to provide an annual Distribution Deferral Opportunity Report as

an output from the distribution planning process. The CPUC is expected to issue a Decision on Grid Modernization and DIDF issues in Fourth Quarter (Q4) 2018.

- PG&E is moving forward with demonstrating the ability of DERs to serve as non-wires alternatives in addressing distribution capacity issues (e.g., load serving and DER hosting capacity) while also deferring distribution infrastructure investments. In May and July, PG&E launched two competitive solicitations under the DRP seeking to procure distribution services from third-party owned DERs.
- PG&E, along with the other California utilities, the CPUC and external non-utility stakeholders participated in a workshop to help inform the development of the DIDF, where DERs can be considered and, if cost effective, utilized as Non-Wires Solutions by the utilities to defer deployment of distribution infrastructure.

Update – Smart Inverter Standards/Certification

On August 18, 2017, the Joint IOUs submitted their respective Advice Letters for CPUC approval changing the Rule 21 Tariff to incorporate various Smart Inverter provisions. These provisions mandate smart inverters to have the following features:

1. Capability to provide data pertaining to DER dispatch and operation (e.g., voltage, real and reactive power consumption/production) to optimize decision-making around grid management.
2. Control capability for aggregator and/or distribution operator of Smart Inverters, such as “on-off,” “ramp-up/down,” and power level settings to enable DER output in service of grid management.
3. Scheduling capability requirements to enable future market functions.

PG&E’s Grid Vision

In its vision, PG&E outlined four key capabilities that form the foundation for implementation:

- Integrate clean and distributed energy resources
- Enhance decision making
- Automate and self-heal

- Enable customers

PG&E progressed these capabilities over the reporting period through the EPIC Program, DRP activities, Smart Inverters Standards/Certification advancements, Smart Grid Pilot Program (completed), customer programs, and other projects across Distribution, Transmission, Security, and IT.

Integrate Clean and Distributed Energy Resources (DERs)

To enable the integration of clean DERs, Utilities must determine ways to more effectively use DERs as a resource which can be dispatched to provide benefits to DER owners and enhance the electric grid.

One example of how PG&E is planning for this future is the EPIC 2.02 Distributed Energy Resource Management System (DERMS) technology demonstration. This project is demonstrating a pre-commercial DERMS system to coordinate the control of various types of DERs, particularly third-party-aggregated Distributed Generation (DG) and storage resources. Development, testing and demonstrations of DERMS will further California's goals to adopt higher amounts of DERs on the grid while providing operators with the necessary control mechanisms to operate the grid safely, reliably and effectively. An effective DERMS could integrate customer-sited DG into grid operations to improve grid resiliency and reliability. However, due to the relative novelty of this technology, commercially-tested viable solutions do not currently exist.

PG&E has partnered with General Electric to demonstrate a DERMS system under the EPIC Program. Given the significant DER growth, the opportunities for utilities to partner with technology companies will continue to grow and be a key component of developing future capabilities.

Enhance Decision Making

As utilities accumulate increasingly larger data sets, and as the introduction of customer-owned DERs introduces new types of data and challenges, the importance of processing that data into actionable insights will be critical. This includes building the capability to gather critical data, making data useful with visualization and analysis, and incorporating data into business processes to benefit customers.

An example of building this capability is *EPIC 1.05 – PG&E Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output*, for which developed the PG&E Operational Mesoscale Modeling System (POMMS). POMMS is a more granular meteorological model providing detailed weather forecasting input to various areas including PV generation. This model also improves the accuracy of forecasting large storms, allowing for increased efficiencies in storm preparation, enhanced accuracy of identifying fire risks, and improved reliability and safety. As part of this effort, PG&E developed and demonstrated SolSource, a comprehensive database of historical, real-time, and forecast solar irradiance data—a scalable method to translate irradiance into PV power output on a customer-by-customer basis. SolSource also provides an internal interface to deliver solar irradiance and power output data to other projects and initiatives.

Automate and Self-Heal

The third capability is to automate complex and high volume tasks. This removes human error or ambiguity and allows operators to focus on higher order critical activities.

EPIC 2.14 – Automatically Map Phasing Information, which seeks to develop algorithms that can identify to which phase (of three) a service point is connected, enhances this capability. Understanding the phase of a customer is an important input to other analytical functions, but the industry's current method is to send field crews to every service point and measure the phase. This project aims to develop more effective processes to capture and maintain the customer phasing. If proven, the technology would allow automation of the task of mapping phases, which increases in importance with more DERs on the grid.

Enable Customers

The final capability is to enable customers. More customers are seeking increased choices and information about how they manage their energy consumption—expectations which must be enabled.

An example of this is *EPIC 1.25 – Direct Current Fast Charging (DCFC) Mapping*. A barrier to customer adoption of EVs is a lack of convenient DCFC charging stations. These types of stations allow customers with DCFC-ready EVs to recharge to 80 percent in less than 30 minutes. This project identified optimal locations within PG&E's territory for the placement of DCFCs based on factors such as cost, available service transformer capacity, traffic patterns, available site host and driver preference. Using a variety of inputs, the team then identified over 14,000 individual potential charger host sites, such as businesses, parking lots, and public places. The results of the project were developed into an interactive online map that visualizes the optimal, and prioritized DCFC locations.

Pilots and demonstrations have significant potential to enhance utility capabilities that will one-day benefit PG&E's customers. Where proven, pilot technology can move be proposed for full deployment as part of future General Rate Cases (GRC).

The remainder of this report is organized as follows:

Chapter 2 provides an update of the progress on PG&E's Smart Grid Deployment Plan and projects from July 1, 2016 through June 30, 2017.

Chapter 3 provides an update on the Smart Grid metrics approved by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 12-04-025.

Chapter 4 provides concluding remarks on this Annual Report.

Chapter 5 provides an appendix of recorded project costs and closed projects.

CHAPTER 2

PG&E'S SMART GRID DEPLOYMENT PLAN AND PROJECT UPDATES

2. PG&E's Smart Grid Deployment Plan and Project Updates

Pursuant to D.10-06-047, Ordering Paragraph (OP) 15 and the Smart Grid Deployment Plan D.13-07-024, OP 4, PG&E provides this Smart Grid Annual Report with the following information included:

a) A summary of PG&E's deployment of Smart Grid technologies during the reporting period (July 2016 through end of June 2017) and its progress on its Smart Grid Deployment Plan.[1]

b) The costs and benefits of Smart Grid deployment to PG&E's customers during the past year, including a monetary estimate of the health and environmental benefits that may arise from the Smart Grid where possible.[2]

c) Current PG&E initiatives for Smart Grid deployments and investments.

d) Updates to PG&E's security risk assessment and privacy threat assessment; and PG&E's compliance with North American Electric Reliability Corporation (NERC) security rules and other security guidelines and standards identified by the National Institute of Standards and Technology (NIST) and adopted by the Federal Energy Regulatory Commission (FERC).

Consistent with PG&E's Smart Grid Deployment Plan, PG&E's Smart Grid Annual Report provides information on the status of its PG&E's Smart Grid investments, including Smart Grid Baseline Projects, Smart Grid-Related Customer programs, and proposed Smart Grid Roadmap Projects.[3] For convenience of review, PG&E's Smart Grid investments are combined in this Annual Report.

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[1] Unless otherwise specified, PG&E has provided cost and benefits for all projects for the period beginning July 1, 2016 through June 30, 2017.

[2] For information on project costs and benefits in former years, please reference past Smart Grid Deployment Plan Updates on CPUC's California Smart Grid website at: www.cpuc.gov/General.aspx?id=4693.

[3] PG&E's Smart Grid Deployment Plan, Application (A.) 11-06-029, Chapters 4, 5 and 6.

2.1. Summary of Updates to PG&E's Smart Grid Deployment Plan

The Smart Grid Deployment Plan filed with the Commission in June 2011 and approved in July 2013, forms the foundation for PG&E's approach to modernizing the grid to support new customer demands on the grid. Since its initial preparation and review by the Commission, PG&E is increasing its Smart Grid Program focus on integrating increasing levels of DERs, energy storage, and EVs into the grid. PG&E is leveraging foundational investments in SmartMeter™ devices, distribution automation, and other technologies identified in PG&E's original Smart Grid Deployment Plan. While the focus of the plan is shifting to account for new and emerging grid needs, the plan continues to describe PG&E's goals and objectives and reflects PG&E's plans to modernize its grid. PG&E's plan is consistent with the Commission's goals and pursuant to Senate Bill (SB) 17. As summarized earlier and described in more detail later in this report, PG&E has made progress implementing approved Smart Grid projects and initiatives, seeking approval in various proceedings to further advance the plan and provide benefits to its customers.

Smart Grid and Supplier Diversity

Through its nationally-recognized Supplier Diversity Program, PG&E has worked for over 36 years to bring more small-, women-, minority-, LGBT- and service-disabled veteran-owned business enterprises (collectively, Diverse Business Enterprises or "DBEs") into its supply chain. In 2016, PG&E spent $2.85 billion with diverse businesses for a 44.4 percent total DBE spend. PG&E continues its demonstrated success in DBE outreach, development and partnership in all categories of procurement, including Smart Grid.

2.2. Summary of Benefits for Select Projects

PG&E's Smart Grid Benefits Summary

This year, PG&E's Smart Grid benefits continued to grow, adding an estimated $204.6 million of incremental savings from July 2016 through end of June 2017 for select projects (shown below).

Table 1-1: PG&E's Smart Grid Estimated Project Benefits – July 2016 to June 2017[4]

	Annual Savings
Direct Customer Savings	$2.5 million
Avoided Costs (Capital, Environmental, and Customer Energy Usage)	$6.4 million
Customer Reliability Benefit[5]	$195.7 million[6]
Total Benefits	**$204.6 million**
Reliability	42 million customer minutes avoided

Projects that contribute to PG&E's Smart Grid project benefits include:

- PG&E's SmartMeter™ Outage Information Improvement ($2.5 million)
- PG&E's Energy Alerts ($1.8 million)
- PG&E's Automated DR Program ($713.5 thousand)
- PG&E's FLISR project ($195.7 million)
- PG&E's Modular Protection and Automation Control (MPAC) project ($3.9 million)

4 For information on project benefits in prior years, reference past Smart Grid Deployment Plan Updates on CPUC's California Smart Grid website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

5 Reliability benefits may vary between the California IOUs due to differences between the projects included and calculated time period of accumulated benefits.

6 Customer Reliability Benefit for Fault Location and Service Restoration (FLISR) since inception is $453 million, with 230 million customer minutes avoided. When compared to former years, FLISR benefits increased over this reporting period due significant weather events which increased the outage volume, creating greater opportunity for FLISR to automatically restore.

Benefits Methodology

Direct Customer Savings Benefits (Energy Alerts / Automated Demand Response)

Direct Customer Savings benefits were derived from PG&E's Energy Alerts Program and PG&E's Automated Demand Response (AutoDR) Program. PG&E's Energy Alerts benefits reflect quantification of energy savings and demand savings resultant of the programs' offerings. For the AutoDR Program, benefits include compensation for reducing load varies according to the program that the customer enrolls in and the amount of load that the customer is able to reduce. For this analysis, the assumption of DR Program compensation was based on the Program rate of $0.50/kilowatt-hour (kWh).

Avoided Costs (SmartMeter™ Outage Information Improvement / Modular Protection and Automation Control)

Avoided cost benefits represent the total avoided costs associated with SmartMeter™ Outage Information Improvement and the MPAC. SmartMeter™ Outage Information Improvement project delivers reliability and operational benefits through leveraging SmartMeter™ data to better understand and resolve customer outages. The program reduced an estimated 22,500 "truck rolls," saving over $2,500,000 over the reporting period. MPAC helps improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities. Over the past year, the MPAC Installation Program has avoided $3.9 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $55 million.

Reliability Benefits (Fault Location and Service Restoration)

Reliability benefits come primarily from PG&E's FLISR project. FLISR limits the impact of outages by quickly opening and closing automated switches. What may have been a one- to two-hour outage can be reduced to less than five minutes. For the purposes of this report, the benefits are estimated using a Value-of-Service reliability model developed by the Lawrence Berkeley National Laboratory.

2.3. Smart Grid Project Updates

PG&E continues to invest in Smart Grid related projects and initiatives with the objective of enhancing its grid infrastructure to provide safe, reliable and affordable energy services to its customers. Over the past year, PG&E has continued the implementation of key Smart Grid related projects outlined in its Smart Grid Deployment Plan. The projects that PG&E has implemented, or plans to implement, focus on areas such as customer engagement and empowerment, Transmission and Distribution (T&D) automation and reliability, safety and operational efficiency, cybersecurity, and integrated and cross-cutting systems. PG&E and the industry continued to gain additional information and knowledge as a result of these efforts. PG&E uses this information to enhance its understanding of the capability of its grid operations, the potential for deployment of innovative Smart Grid technologies, and customer expectations as they relate to the Smart Grid.

2.4. Customer Engagement and Empowerment Projects

Over the past year, PG&E has made steady progress on a number of projects to provide customers with tools necessary to manage their energy usage and costs. PG&E considers its customers to be the primary driver of its Smart Grid Program. Therefore, without an engaged and empowered customer population, many benefits offered by a Smart Grid would be difficult to realize. PG&E believes that continuing to leverage SmartMeter™ and data access technologies to provide customers with greater benefits and demonstrate the importance of utilizing customer demand-side programs is vital to support PG&E's efforts to help customers understand their energy use and manage their energy bills.

PG&E is also undergoing efforts to enhance customer access to EV infrastructure and programs. PG&E's new EV Charge Network was recently approved by the Commission. The network will significantly expand access to EV charging stations throughout northern and central California over the next three years. By supporting adoption of EVs, the program extends efforts to reduce greenhouse gas (GHG) emissions across the state. In addition, PG&E continues outreach activities to EV drivers to increase awareness of the EV Rate Program and other options for customers to reduce fuel costs. This includes a partnership with Center for Sustainable Energy (CSE), the administrator of the state's Clean Vehicle Rebate Project, to reach new EV drivers.

PG&E also supports several EV ride-and-drive events each year to connect with customers interested in electric drive technologies and rates.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2016 through June 30, 2017, unless otherwise noted.

2.4.1. Demand Response Projects

Supply Side (SSP) / Supply Side II (SSP II) DR Pilot (Continuation of IRM Pilot Phase 2)	Approximate Cost Over Reporting Period: $0.59 Million
Description: The Supply Side DR Pilot (SSP) is a continuation of the Intermittent Renewables Management Pilot Phase 2 (IRM2) and was approved as part of the 2015-2016 DR Bridge Funding (D.14-05-025). The IRM2 was originally proposed in PG&E's 2012-2014 DR application and approved by the Commission in D.12-04-045. As part of the 2015-2016 DR bridge funding Decision, the Commission approved a continuation and expansion of the IRM2 in D.14-05-025. This continuation, known as the SSP, ran from 2015 through 2016 and expanded the IRM2 by enabling participation in the wholesale real-time energy and non-spinning reserve ancillary services markets for non-residential customers, moving closer to an Resource Adequacy construct with 4-hour bid block requirements, and expanding participation from large commercial and industrial (C&I) customers to include smaller commercial customers and residential aggregators. The SSP was initially scheduled to run through 2016. However, PG&E subsequently received approval from the CPUC in D.16-06-029 to extend the SSP through 2017 (renamed the SSP II in 2017). The SSP II continues the work started in the SSP as well as expanding to investigate the ability of wholesale DR to provide distribution services, specifically investigating how to operationalize the interactions between wholesale market availability and distribution services availability and starting to develop a method for dispatching available DR resources based on distribution operational needs. Funding Source: Funding for this pilot through 2016 (SSP) was approved by the CPUC as part of the 2015-2016 DR Bridge Funding (D.14-05-025). Funding for the pilot in 2017 (SSP II) was approved by the CPUC in D.16-06-029. Status: Participants have continued to bid into the wholesale energy market. Between April 2015 and June 2017, pilot participants have submitted over 8,000 bids and received over 1,000 awards in the wholesale day-ahead energy market. Though several residential aggregators have started the pilot enrollment process, to date none have completed the process. In 2017, the SSP II is investigating the operational feasibility of utilizing DR resources that are integrated in the wholesale energy market to address local distribution needs. Benefits Description: The SSP is a gateway for more DR resources to be integrated into the CAISO wholesale market. PG&E has structured the pilot as a bridge between the retail and wholesale market as well as an avenue for third-party DR providers to participate in the CAISO wholesale market. This step is vital in order to have a self-sustaining third-party DR market in California. Learnings from the SSP were integrated into PG&E's proposed enhancements to its Capacity Bidding Program included in its 2018-2022 DR Application, and future results from the SSP II, in addition to inputs from the DRP and Integrated Distributed Energy Resources proceedings, may be used to inform a proposal for distribution service offerings in future DR programs. The SSP II will also provide a pathway for new technologies. Technologies behind the customer meter, such as storage or Smart	

devices, have a vital role to serve as grid-responsive assets. DR programs will act as gateways for participants to provide their demand and energy reduction that is tied to the needs of the CAISO and distribution operations. Results of the SSP II will help PG&E and the Commission assess the benefits of DR as a gateway to grid benefits and provide an in-depth understanding of the benefits of technologies, like energy storage and EVs. Benefit Category: Smart Market – PG&E is continuing to evaluate the value streams of enabling DR resources in a changing operations environment and to provide services to facilitate the reliable and cost-effective integration of renewable resources. PG&E is pursuing discovery of the necessary program attributes that transmission and distribution system operators will need in the future.

Demand Response Transmission and Distribution System Integration	**Approximate Cost Over Reporting Period:** **$0.6 Million**
Description: In T&D System Integration, PG&E will evaluate areas where existing and future DR programs can be implemented and designed to support PG&E's T&D planning and operations. Funding Source: Funding for this project is provided under PG&E's 2012-2014 DR Proposal approved by the Commission in D.12-0--045. Funding was extended through 2015-2016 program cycle in D.14-05-025. Status: This project is complete. The first phase of the pilot was concluded in First Quarter (Q1) 2015. The first phase included a study of the required DR resource characteristics to meet distribution needs. The pilot conducted field demonstration projects as part of 2015-2016 DR Bridge Funding Activities (D.14-05-025). Demonstration projects included the deployment of local DR resource zones that can be called by Distribution Operations to maintain local system reliability, development of behavioral DR resources that can be locally called by Distribution Operations and testing the feasibility of automated calling of DR resources linked to Supervisory Control and Data Acquisition (SCADA). The final DR T&D Pilot report was submitted in April 2017. Benefits Description: In the long run, the benefits of this project would include the use of DR as a cost-effective resource to provide local T&D grid reliability, especially as more intermittent resources are connected on the grid. Benefit Category: Smart Utility – PG&E is continuing to evaluate the value streams of enabling DR resources and to provide new services to support T&D operations. PG&E is pursuing the necessary program attributes that T&D operators will need now and in the future.	

AC Cycling Next Generation Technology Assessment	Approximate Cost Over Reporting Period: $6.3 Million

Description: Under its direct installation program, SmartAC™, PG&E has deployed over 200,000 one-way paging air conditioner direct load control devices since 2007. In order to leverage its investment in the Advanced Metering Infrastructure (AMI) network and in order to improve the reliability of this resource in anticipation of CAISO market integration of DR resources in 2018, PG&E tested two-way communicating load control switches over the course of three years.

In 2013, PG&E conducted a targeted technology assessment of a ZigBee protocol based Loda Control Receiver that connected through a SmartMeter™. In 2014, PG&E conducted a Request for Quote (RFQ) and a subsequent laboratory test of two different switches using the Zigbee protocol, another that used a Silver Spring Network proprietary direct-to-grid approach and a cellular communication module switch. In 2015, PG&E worked with the manufacturers of these devices to develop features that provide greater benefits and real time monitoring of key statuses. In 2016, PG&E conducted a field test of three different models and chose a winner, the Energate LC2200 with a Zigbee protocol communication module.

Funding Source: Funding for this project is currently provided under PG&E's 2017 Bridge Funding Budget for 2017 Demand Response Programs and Activities as approved by the Commission in D.16-06-029.

Status: Based on reports indicating higher than forecast rates of failure of the commercial paging networks which support the SmartAC Program, PG&E has begun the deployment of two-way switches in 2017, instead of 2018 as previously planned. Under a multi-phase approach, at least 5,000 devices will be installed in 2017. PG&E will build IT systems to provide real-time status updates via integration between the head-end system for the two-way switches, the Home Area Network Communication Manager, and a dashboard in the DRMS (Lockheed's See Load) in 2018.

Benefits Description: Because two-way switches are associated with healthy SmartMeter™ devices, the reliability rate of this resource will improve over one-way paging devices. Also, by installing two-way direct load control devices, PG&E will have near real-time visibility into an individual premise and the air conditioner's actual response to a load control event signal. This will facilitate early detection of device malfunction in either under- or over-performance circumstances and lost load can be recaptured quicker. Currently, PG&E uses SmartMeter™ data to determine an estimate of the number of non-performing devices in its maintenance program. With a disconnect alarm on a two-way switch, unnecessary truck rolls can be avoided to sites.

Benefit Category: Smart Utility – The two-way technology will provide greater visibility into device behavior, which will be used in more accurate forecasting of load reduction during events, increase the load reduction value per customer, and provide efficiencies in program management operations.

2.4.2. Electric Vehicle Integration Projects

Demand Response Plug-In Electric Vehicle (DR PEV) Pilot	Approximate Cost Over Reporting Period: $1.6 Million

Description: The DR PEV Pilot aims to demonstrate the technical feasibility as well as the value of managed charging of EVs as a flexible and controllable grid resource. The main goal of this project is to understand the potential of using EVs for grid services, which can result in cost savings associated with operating and maintaining the grid as well as owning and operating a vehicle. The pilot requires BMW to provide a minimum of 100 kilowatts (kW) of capacity at any given time, regardless of how many BMW i3 EVs are charging. BMW is required to provide this capacity in the form of existing grid services as defined by the CAISO. To date, BMW has elected to provide direct access (DA) and real-time (RT) energy services. To meet the managed charging component, BMW has enrolled 95 BMW i3 drivers located within the South Bay Area (PGP2 SubLAP) to participate in this pilot. Once an event is called, BMW utilizes proprietary aggregation software to delay charging of participating customers (via telematics embedded in the vehicle) in order to reduce load on the grid. The algorithm prioritizes the reduction of electricity consumption from charging without interfering on customers' mobility needs; however, drivers can opt-out of event participation at any time. To address uncontrollable fluctuations regarding managed charging capacity, BMW developed a stationary battery system made up of eight used MINI E batteries (100 kW/225 kWh) as back-up storage to fill the gap between available load drop from managed charging and the required DR capacity.

Funding Source: Funding for the project is provided under the 2012-2014 DR Program.

Status: On April 2, 2013, this project was approved per Advice Letter 4077-E-B. On August 16, 2013, PG&E released a Request for Information (RFI) to automakers and received responses from various parties. Building off of the RFI, PG&E released a Request for Proposal (RFP) on April 30, 2014 to auto makers selecting BMW in August 2014. PG&E and BMW executed contracts in December 2014 and officially launched the pilot in January 2015. PG&E and BMW ramped up the project implementation and customer enrollment between January and July 2015. Over the course of 18 months, from July 2015 to December 2016, the Demand Response Plug-in Electric Vehicle Pilot dispatched 209 DR events, totaling 19,500 kWh. On average, 20 percent of the total contribution was attributed to the vehicle pool and 80 percent from the second life stationary battery system. The amount from the vehicle share is dependent on what time of day an event is called. If an event is called from 11 p.m. to 2 a.m., the vehicle pool contributes more significantly by increasing the share from 20-50 percent of the 100 kW required. This increase in vehicle pool contribution is the result of PG&E's residential EV and time-of-use (TOU) rate plans which provide lower cost electricity prices during this time period, creating incentive for people to charge during these hours.

The Pilot is deemed a success both from an energy reduction and customer satisfaction standpoint. Participants were very satisfied with the program and were active participants in the research component as well. Based off customer research, 98 percent of participants indicated that they were satisfied with the program and 93 percent stated that they are likely to participate in a similar program in the future if offered. Since this program was designed to run primarily in the background of customers' lives, they were able to participate at high rates and felt little to no customer fatigue. Results indicate that the EV owners have a strong interest in supporting renewable energy through managed charging programs. They are willing to participate in managed charging or charge during the day as long as they are not inconvenienced or limited in their ability to use their car. The largest barrier to day time charging and managed charging is the lack of workplace charging. For further project information, see: BMW i ChargeForward: PG&E's Electric Vehicle Smart Charging Pilot (http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf).

Benefits Description: As part of this project, PG&E will be able to evaluate the capabilities and willingness of EV owners and automakers to participate and provide grid services to the Utility. Providing these services may result in cost savings associated with operating and maintaining the grid as well as owning and operating a vehicle. Added grid services can potentially reduce the need to increase California's electricity generation capacity and is aligned with the State's loading order for resources, effectively reducing energy procurement costs.

Benefit Category: Smart Market – PG&E will be able to assess the development of the DR - PEV market to provide grid services to the Utility.

Electric Vehicle Rates	Approximate Cost Over Reporting Period: $0.1 Million

Description: PG&E's EV rates provide customers with a TOU, non-tiered electric rate schedule that allows drivers to recharge their EVs at a fraction of the cost of gasoline. By incentivizing charging overnight, the rate also helps PG&E integrate new EV charging load by shifting demand into off-peak hours when there is ample capacity on the utility grid. The EV rates also remove the tiered rate structure of PG&E's default residential rates, which can cause EV charging to be as costly as, or more expensive than, gasoline for higher-usage customers. PG&E offers two EV rates to customers: EV-A allows customers to meter their home usage and EV charging together; while EV-B involves installation of a second utility meter to bill only vehicle charging on the EV rate. Since their introduction in 2013, PG&E has enrolled over 36,000 customers on the EV rate, representing 30 percent of the total registered EVs in PG&E's service territory to date.

Funding Source: GRC

Status: PG&E continues outreach activities to EV drivers to increase awareness of EV rates and other options for customers to reduce fuel costs. This includes a partnership with CSE, the administrator of the State's Clean Vehicle Rebate Project, to reach new EV drivers. PG&E also supports several EV ride-and-drive events each year to connect with customers interested in electric drive technologies about rates. The rate has an enrollment cap of 60,000 and is being evaluated by the CPUC along with other residential rates in the Utility's GRC. For further project information, see Joint IOU Electric Vehicle Load Research Report (Located on CPUC EV website: http://www.cpuc.ca.gov/General.aspx?id=5597) (latest version: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M171/K806/171806139.PDF).

Benefits Description: The current off-peak price for electricity on the EV rate $0.12/kWh, equivalent to approximately $1.20/gallon of gasoline. This low off-peak price allows EV drivers to realize significant fuel cost savings compared to gasoline, which is currently priced between $2.50-3.00 per gallon in California. As a result of the significant savings off-peak, PG&E estimates that 80 percent of EV charging is done during the hours of 11 p.m. to 7 a.m., when prices are lowest. This will lower overall charging costs for customers as well as costs for PG&E associated with peak energy use.

Benefit Category: Engaged Customer – this program increases customer awareness and engagement in managing their energy use. With one EV accounting for roughly half of the annual consumption of a typical home, shifting charging behaviors away from peak periods can allow PG&E E to avoid upgrades to local distribution infrastructure, as well as costs for expensive

peak-hour energy procurement.

Electric Vehicle Infrastructure	**Approximate Cost Over Reporting Period:** **$1.0 Million**

Description: PG&E's EV Charge Network Program is a three-year pilot which enables the deployment of service connection and supply infrastructure (make-ready infrastructure) to support up to 7,500 EV Level 2 charging ports. The program focuses on serving two key market segments, workplaces and multi-unit dwellings. Charging ports may be owned by either Site Hosts or PG&E, with PG&E able to own up to 35 percent of installed ports in multi-unit dwellings and workplaces located in disadvantaged communities. PG&E also administers rebates and participation payments for the EV chargers contingent upon the Site Hosts' attributes, physical location, and ownership model selected. The total program cost will not exceed $130 million.

Funding Source: This project was funded through the PG&E EV Balancing Account.

Status: In 2017, PG&E is laying the foundation for program launch in 2018. PG&E is collecting Site Host interest through a web portal, working with trial sites to demonstrate program deployment, and is designing a website, application form, and marketing plan for program launch. PG&E is also conducting solicitation processes for EV chargers. Quarterly RFQs are held for the Charge Owner model (Site Host ownership) and a single RFP is being held for the Charge Sponsor model (PG&E ownership). The establishment of rebates and participation payments are also based on prices received during the procurement process. The program will launch in 2018 and scale to completion in 2019 and 2020. For further project information, see: EVCN Quarterly Report (Latest version: http://quicktake.morningstar.com/stocknet/secdocuments.aspx?symbol=evcn&country=deu).

Benefits Description: The EV Charge Program positions PG&E at the nexus of customer service and emerging infrastructure needs. Public charging infrastructure is needed for California to meets its goal of 1.5 million zero emission vehicles on the road by 2025. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent. PG&E is also mindful of potential grid benefits that EV charger deployment may drive, such as load shaping through DR communications and the establishment of load management guidelines. This charging and pricing data will help inform strategy for rapid EV growth across the state.

Benefit Category: Smart Utility

2.4.3. SmartMeter™ Enabled Tool Projects

Energy Diagnostics and Management (includes, Home Energy Reports, Business Energy Reports, My Energy Portal)	Approximate Cost Over Reporting Period: $6.3 Million

Description: The Energy Diagnostics and Management Project is the implementation of a comprehensive strategy for customer self-service demand-side management. The project is enhancing the online My Energy platform and launching new tools to help customers understand their energy bills, how they use and generate energy, rate options, and savings opportunities. In addition to launching new versions of existing online tools, the current Home Energy Report Program has been scaled to 1.5 million residential customers. A Business Energy Report (BER) Emerging Technology field test was designed and implemented to determine the impact of monthly reports on small and medium businesses (SMB). These BERs were developed and provided by Opower and EnerNOC, focused on behavioral interventions, sent by mail, to encourage energy conservation in both gas and electricity. Follow up did not find any gas or electricity savings from the treatments tested.

Funding Source: This project was funded through the Energy Efficiency (EE) and DR Balancing Accounts and GRC. Approximate costs listed reflect total budget allocated to project over the duration of the reporting period.

Status: The project was launched in May 2015 and development completed in March 2017. It replaces the existing contract to provide Home Energy Reports and existing My Energy portal functionality.

Benefits Description: This project provides residential and small and medium non-residential customers with actionable information and personalized recommendations on how they can save energy find the best rate for them and explore DG and EV options.

Benefit Category: Engaged Consumer – the project increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner.

Energy Alerts	Approximate Cost Over Reporting Period: $0.024 Million

Description: The Bill Forecast Alert feature allows customers to set personalized budget thresholds and are notified via email, text, or phone when they are projected to exceed that amount during their monthly billing cycle. Customers with a single premise, with a SmartMeter™, on their account, and on an supported rate plan (HG1, HE1, HE6, HE7, HE8, HE9, HEA9, HEB9, HEVA, HEVB, HETOUA, HETOUB, G1, E1, E6, E7, E8, E9, EA9, EB9, EVA, EVB) are eligible. The following classes of customers are not supported: DA, Community Choice Aggregation, and Net Energy Metering.

Funding Source: This project was originally funded under PG&E's SmartMeter™ Upgrade Program and received additional funding under GRC's capital fund and expense.

Status: The Energy Alerts Program was updated in April 2016. The original Energy/Tier Alerts Program that originated in June 2010 officially concluded on March 1, 2016. This alert program was updated due to tier collapse and tier restructuring. PG&E also received customer feedback that the previous alert program did not allow personalization and that customers had confusion regarding the effect of tiers on their total bills. To alleviate the confusion, the Company provided information and tips on the updated alerts program web page on how to set an alert to mirror the tier structure. On April 1, 2016, the updated Energy Alerts Program was launched with over 113,000 customers that transitioned from the previous Energy/Tier Alert Program.

Benefits Description: Energy Alerts provides enrolled customers with a monthly projected bill amount notification when their current usage pattern is expected to exceed their personalized Energy Alert amount. This alert will help customers adjust their consumption patterns to avoid paying higher energy bills or financially plan for their estimated bill amount. During calendar year 2016, Bill Forecast Alert participants saved approximately 9.2 gigawatt-hours (GWh) of energy and 2.7 MW of residential peak demand in 2016. This reflects an energy savings increase of 15 percent over 2015's total of 7.8 GWh. Participants only enrolled in Energy Alerts/BFA saved an average of 112.2 kWh per customer in 2016, versus 86 kWh per customer in 2015. Bill Forecast Alert participants, who also participated in PG&E's online My Energy, saved an average of 59.9 kWh per customer in 2016 versus 87 kWh per customer in 2015.

Benefit Category: The direct benefits are consumer savings of approximately $1.8 million dollars of electricity costs (9.2 GWh * $0.19979/kWh). Benefits such as environmental GHG reductions, avoided T&D upgrades are tangible but unquantified in the study.

Benefit Quantification Methodology: The evaluation was conducted in five basic steps:

1. Characterize the participants enrolled in Bill Forecast Alert (BFA) and/or My Energy by examining both enrollment data and level engagement.

2. Design the treatment samples for single enrollment in each program and for dual participation by segmenting the population according to the aspects of participation that have been shown to be correlated with savings in previous evaluations and then by stratifying based on energy use within relevant population segments. For My Energy, the segmentation aspects include duration of participation and number of times a participant views the web tools. For Energy Alerts/BFA, the segments include continuing participants that transitioned from Energy Alerts to BFA in March 2016 (subsequently referred to as Energy Alerts/New BFA) and New BFA participants.

3. Match the treatment customers with non-participant control customers using a stratified matching strategy, employing both demographic and pretreatment energy usage data. Conduct matching in two stages: first, with monthly billing data to obtain a three-to-one control-to-participant match; and second, with hourly on-peak and off-peak interval data to create a one-to-one control-to-participant match for a series of day types.

4. Estimate the energy savings for each program at the segment and population levels for each month and the entire program year first using a statistical difference-in-difference (DID) technique, then refining the estimates using a regression approach.

5. Estimate the demand savings for each program at the segment and population levels for each day type using a statistical DID approach.

Full Report: *Pacific Gas & Electric Company's SmartMeter™ Enabled Programs: Program Year 2016 Evaluation of Customer Web Presentment and Bill Forecast Alert.* CALMAC ID PGE0379.01 Applied Energy Group, Inc. 2017. For further project information, see: OP10 compliance report, Progress on Residential Rate Reform (http://www.cpuc.ca.gov/General.aspx?id=12154).

Share My Data (Customer Data Access) Project	Approximate Cost Over Reporting Period: $1.85 Million

Description: Under the Customer Data Access (CDA) project, now known as "Share My Data," PG&E developed a platform that provides authorized and secure data to customer-authorized third parties. With the release of CDA Phase 1 functionality, customers could share electric energy usage data with third parties. With the release of the CDA Phase 2 functionality in December 2015, customers could also opt to share one or more categories of information, including usage (e.g., interval usage data for gas consumption), billing (e.g., rate schedules, billing history) and account (e.g., service address).

Funding Source: This project was funded by the CDA D.13-09-025 through December 2016. As of January 2017, this project is funded through GRC.

Status: On September 19, 2013, the CPUC approved PG&E's CDA Application (D.13-09-025). PG&E launched Phase 1 of the Share My Data project in March 2015 and Phase 2 on December 18, 2015. PG&E filed Advice Letter (AL) 4992-E on January 3, 2017 in compliance with OP 10 of D.16-06-008. PG&E seeked approval for improvements to the Electric Rule 24 process for Demand Response Providers (DRP) to obtain customer authorization to access the customer's data for direct participation in the CAISO's wholesale market. This includes electronic authorization via the Share My Data platform. Draft Resolution E-4868 was issued by the commission on AL 4992-E on July 11, 2017.

Benefits Description: This platform provides PG&E's customers and their selected third-party service providers with a robust means of accessing their energy data in a standardized manner. It also supports the evolution of the energy services industry by providing the data necessary for third parties to develop applications that will help customers manage their energy usage and reduce their monthly energy bills.

Benefit Category: Engaged Consumer – the program increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner.

Energy Data Access	Approximate Cost Over Reporting Period: $0.3 Million

Description: In Commission D.14-05-016 ("Decision"), the Commission adopted rules to provide access to energy usage and usage-related data to local governments, academic researchers, and state and federal agencies for specific use cases, while protecting the privacy of customers' personal data. The Decision ordered the utilities to create a Data Request and Release Program to facilitate this access, and instructed the utilities to submit an updated data catalog in the Smart Grid Annual Report.[7]

Funding Source: PG&E is tracking the incremental costs associated with implementing this decision in a memorandum account and is in the process of seeking authorized recovery of such costs through its GRC proceeding.

Status: In December 2014, PG&E implemented the Decision requirements, which includes the development of an Energy Data Request Program portal, creation of a Data Request and Release Process, publishing of a data request log (referred to as data catalog in the Decision), publishing of a quarterly energy consumption report by ZIP code and customer class, and the formation of a statewide Energy Data Access Committee (EDAC) that meets quarterly to discuss IOUs' data sharing programs. An updated data request log (data catalog) is provided below and summarizes the requests received or fulfilled for period July 1, 2016 through June 30, 2017. The complete log can be viewed on PG&E's website at http://www.pge.com/energydatarequest. The EDAC held its required quarterly meetings through December 2016. Minutes from each meeting are posted on the CPUC's EDAC website: http://www.cpuc.ca.gov/General.aspx?id=10151. The EDAC will continue to meet in 2017 and beyond as needed. For further project information see: Quarterly Advice Letters (Latest filing: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3867-G.pdf).

Benefits Description: This program provides energy consumption and energy-related customer data to qualified academic researchers for research purposes, local governments for their climate action plans, and state and federal agencies to fulfill statutory obligations, including low-income participation in EE programs. The data provided is intended to promote EE, DR, and GHG reductions, and advance Smart Grid policy goals.

Benefit Category: Engaged Consumer – this program facilitates access to energy data for local governments, academic researchers, and state and federal government entities needing data to fulfill statutory requirements.

[7] D.14-05-016, pp. 91-92.

PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2016 – 6/30/2017)				
Organization Name	**Requestor Type**	**Description**	**Status**	**Change Date**
City of Ceres	Local Government	2014-2016 annual gas consumption data to be used for a GHG baseline inventory as part of the General Plan Update process.	Canceled/Withdrawn	6/15/2017
Carnegie Mellon University	Academic Researcher	Sampling of 500,000 residential customers; interval usage, aggregated usage, billing data, and low income program data.	Canceled/Withdrawn	5/15/2017
University of San Francisco	Academic Researcher	Solar data for San Francisco customers.	Canceled/Withdrawn	4/21/2017
City of Berkeley	Local Government	2013-2015 Monthly aggregated residential and non-residential electric and gas consumption by census block group or aggregated block group.	Completed	4/18/2017
CA Dept. of Community Services and Development	Community Services & Development	CSD submitted a "test" request form.	Canceled/Withdrawn	4/14/2017
UCD Center for Water-Energy Efficiency	Academic Researcher	2005-16 monthly billing data, monthly and interval usage data, premise address and lat/long, EE program participation, and billing start and stops dates for all agricultural customers in certain ZIP codes in Monterey, Tulare, Fresno, and King counties.	Completed	4/12/2017
University of California, Davis CWEE	Academic Researcher	Five years monthly billing data, monthly and interval usage data, meter address and lat/long, billing start and stops dates for all agricultural customers in certain ZIP codes in Monterey and Fresno counties.	Canceled/Withdrawn	4/11/2017

PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2016 – 6/30/2017)				
Organization Name	**Requestor Type**	**Description**	**Status**	**Change Date**
Duke University Energy Initiative	Academic Researcher	Researcher requests monthly gas and electric billing data at the address level from 1950, 1960, 1970, 1980 and 1990. Proposal is to study current economic implications of historic housing discrimination (“redlining”).	Denied	4/11/2017
City of Chico	Local Government	2010-2016 residential gas and electric data aggregated to census block group.	Completed	3/24/2017
Energy Council	Local Government	2011-2016 Total aggregate gas and electric usage for all Industrial customers, and total aggregate gas and electric usage for all DA customers in Alameda County.	Canceled/Withdrawn	2/2/2017
City of Fremont	Local Government	2013/14 residential usage by ZIP, plus quarterly recurring for additional two years (electric & gas) through Q4 2016.	Completed	1/22/2017
Town of Los Altos Hills	Local Government	Residential aggregated interval and monthly billing gas usage for the Town of Los Altos Hills by TOT code for 2005, 2012 and 2015.	Canceled/Withdrawn	1/17/2017
City of Los Altos	Local Government	2014-2015 aggregated Residential and Commercial consumption data for Climate Action Planning and public dashboard reporting.	Canceled/Withdrawn	10/19/2016
UC Berkeley	Academic Researcher	Number and electric and gas usage for residential customers at ZIP+4 in counties: Alameda, Contra Costa, Marin ,San Francisco ,San Mateo, Santa Clara, Napa, Solano, and Sonoma.	Canceled/Withdrawn	10/12/2016

PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2016 – 6/30/2017)				
Organization Name	**Requestor Type**	**Description**	**Status**	**Change Date**
California Energy Commission	State or Federal Agency	Customer level, anonymous monthly electricity and natural gas data organized by North American Industry Classification System (U.S. Census industry statistics) category and zip code within Sonoma County.	Canceled/Withdrawn	10/12/2016
Menlo Spark	Community Services & Development	2014-2015 annual electric and gas usage and heat map for ZIP code 94025.	Canceled/Withdrawn	8/30/2016
University of Illinois	Academic Researcher	5.5 years gas and electric residential usage by ZIP+2, billing dates and amounts, indicator for master meter, open/close account date, premise street address and lat/long, baseline territory, indicator for net metering (no usage data).	Completed	7/10/2016

Stream My Data aka Home and Business Area Network (HAN)	Approximate Cost Over Reporting Period: $0.4 Million

Description: PG&E's Stream My Data helps customers save energy and money by providing RT electricity data through an energy monitoring device. The device helps a customer understand how and when they are using electricity, as well as the related costs—allowing them to take actions to save energy and money. By connecting an energy monitoring device to the electric SmartMeter™ for the home or an SMB, the customer is able to do the following:

- Monitor your Real-Time Electricity Usage (kW)
- See your Real-Time Price ($/kWh)
- Get an Estimated Costs to Date and Estimated Electric Bill This Month
- Receive Demand Response Event Alerts (SmartRate™ and Peak Day Pricing (PDP) event alerts)

Funding Source: The funding source was based primarily from GRC at $263,418, and additionally from EPIC 2.21 pilot at $133,329.

Status: "Stream My Data" aka HAN, continues its service with usage available at all SmartMeter™ devices, and PRICE information available to A1, A10, A6, E1, E6, and EVA rates. At the end of December 2016, one HAN vendor cloud service discontinued, and so customers were redirected to another service provider. In mid-April, PG&E experienced a three week outage of PRICE information triggered by back-office IT infrastructure upgrades. This affected roughly 1,900 customers. PRICE information service for all customers resumed early May.

EPIC 2.21 Pilot Enabling ZigBee for Commercial Customers continued during this past year and examined the use of real-time SmartMeter™ HAN technology at 13 large C&I customer sites.

Separately from January to June of 2017, as part of CAISO Telemetry Solution over Broadband project, 312 residential locations having EV chargers were outfitted with HAN devices to access RT usage telemetry.

Benefits Description: Customers are able to use validated HAN devices/technologies to receive RT usage, RT price, and DR signals via their SmartMeter™. This improves their energy awareness and helps them adapt their energy consumption or load shifting behaviors to lower their monthly energy bills, and makes it easier for customers to participate in DR programs.

Benefit Category: Engaged Consumer – HAN enablement allows customers with SmartMeter™ interoperable devices/ technologies to synchronize with PG&E's SmartMeter™.

Building Benchmarking Portal	Approximate Cost Over Reporting Period: $2.9 Million

Description: In early 2017, PG&E launched the Building Benchmarking Portal (Benchmarking Portal) – a new web-based system for customers to receive aggregated whole-building data in their Energy Star Portfolio Manager (ESPM) accounts, complying with Assembly Bill (AB) 802. Under AB 802, aggregate building data can be shared as long as the facility meets a mandatory threshold of number of utility accounts (three or more for commercial, five or more for multi-family). The previous benchmarking process required building owners to identify all accounts in their building and obtain individual tenant authorizations to release the data. The new Benchmarking Portal offers a more resilient and streamlined service for procuring aggregated, whole-building usage data to assist customers in their benchmarking endeavors.

Funding Source: This project is funded through a memo account (MA). PG&E filed a Tier 2 Advice Letter (AL 3707-G/4829-E) seeking to establish memorandum accounts for gas and electric service. These MAs are being used to record costs incurred to comply with AB 802 and will be submitted in PG&E's next GRC. Upon review and approval by the CPUC, PG&E will transfer the AB 802 MA balances to the appropriate gas and electric balancing accounts, as directed by the Commission, for recovery in rates.

Status: In Q1 of 2017, PG&E's Benchmarking Portal went live. Building owners are now able to register buildings through the Benchmarking Portal and create a Web Services connection for aggregate, whole-building usage data in their ESPM accounts.

Benefits Description: For the building owners, the new portal may make it easier for owners to perform benchmarking (i.e., they do not need individual authorizations if the building meets the thresholds) and tenant turnover is not nearly as impactful on the benchmarking process. Additionally, as more customers benchmark their facilities, it will yield greater visibility into building energy use, and opportunities for customers to improve the performance of their buildings.

Benefit Category: Engaged Customer – By simplifying the authorization process, and designing a more robust Web Services connection, the Benchmarking Portal will allow building owners to more easily track and manage facility energy consumption.

Time Varying Pricing (TVP) Rates	Approximate Cost Over Reporting Period: $7.2 Million

Description: TVP products, such as PDP, TOU, and SmartRate take advantage of SmartMeter™ capabilities that are now largely available across PG&E's service territory. Charging customers different rates based on varying system conditions is intended to more closely align retail and wholesale electric prices for generation, as well as create economic incentives for customers to actively manage their energy costs by shifting electricity use from when it costs more to when it costs less. PDP provides between 30-45 MW of load reduction on the hottest days of summer, equaling the load of almost two peaker power plants. The SmartMeter™ has enabled PG&E to cost-effectively offer all customers these types of rate programs which provide significant customer and societal benefits.

Funding Source: This project is funded as part of PG&E's Rate Design Window (D.10-02-032, D.11-05-018, and D.11-11-088 – $97.05 million), 2011 GRC (2011 Phase 1 – $12.61 million), and AMI Cases (D.06-07-027 – $2.07 million).

Status: PG&E continues to administer and offer TVP Rates to all PG&E bundled residential and nonresidential customer classes. Beginning in November 2012, SMB customers with 12 months of SmartMeter™ data began a mandatory transition to TOU rates and two years later, in 2014, began transitioning to default opt-out PDP. Small Agricultural customers began transitioning to mandatory TOU rates annually starting in March 2013. CPUC D.15-07-001 mandates that PG&E's residential customers be defaulted to TOU rates, beginning in 2019. Eligible residential customers may also enroll in the SmartRate Program. Enrollment in SmartRate has grown to over 122,000 residential customers and provides an average of 30-35 MW of load reduction on event days.

Over 430,000 SMB Service Agreements have transitioned to TOU rates in the past five years. More than 210,000 Service Agreements are active participants in the PDP Program as of July 2017. In 2016, PG&E expanded the In Season Support Program for PDP customers to all customers who have provided email addresses and also introduced a pilot program to provide the same customized reporting and analytics via text messaging.

Benefit Description: TVP reduces demand during peak summer time periods, lowering systemwide costs, by enabling customers to save money by shifting load to off-peak times of day. Customers can still use the same amount of energy and reduce their bill by shifting some of their usage to times of lower cost generation.

Benefit Category: Engaged Consumer and Smart Utility – the program increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner while at the same time allowing PG&E greater control and flexibility over its transmission and distribution.

2.4.4. Emerging Customer Side Technology Projects

Automated Demand Response (AutoDR) Program	Approximate Cost Over Reporting Period: $3.6 Million
Description: PG&E's Automated Demand Response (AutoDR) Program offers small, medium and large commercial, industrial and agricultural customers an incentive to install automated equipment that enhances their ability to reduce load during DR Program events. Specifically, AutoDR is an automation-based communication infrastructure that links PG&E's designated third-party hosted solution servers to customer-owned Energy Management Control Systems. PG&E helps its customers to develop pre-programmed energy management and curtailment strategies to automate their facilities which enables them to participate in a DR event day. Funding Source: Since its inception, PG&E's AutoDR Program has been funded under PG&E's DR activities and budgets, which have been authorized by the Commission. Status: PG&E's AutoDR Program has been successful, and is expanding into the residential market segment. PG&E's AutoDR Program continues to provide incentives to large C&I customers. Beginning in 2017, the program incentive will be available to SMB customers as well. And from Third Quarter (Q3) 2017, the AutoDR incentives will be available to Residential customers, too. Benefits Description: The AutoDR Program makes it easier for customers to participate in DR programs in which they can earn compensation for reducing load when called upon. Compensation for reducing load varies according to the program that the customer enrolls in and the amount of load that the customer is able to reduce. For this analysis, the assumption of DR Program compensation was based on the Demand Bidding Program (DBP) program rate of $0.50/kWh, which is publicly available information (https://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-DBP.pdf). For July 2016 – June 2017, AutoDR customers saved 1,427 megawatt-hours (MWh) cumulatively from participating in DR events with the assumption that the customers did not shift that load to another time window. The 2014 GHG emissions rate for delivered electricity in PG&E was of 435 lbs. carbon dioxide/MWh (source www.pgecorp.com). AutoDR customers received a benefit of 620,745 lbs. of GHG reduction. They also received the benefit of financial incentives from DR event participation of approximately $713,500. Benefit Category: Technology Adoption and Customer Engagement – AutoDR incentivizes customers for adopting emerging technologies that help them save energy and reduce costs. The program works with customers to help them identify load shed strategies by which they can participate in DR, thereby providing value to the overall grid.	

Smart Thermostat Study	Approximate Cost Over Reporting Period: $1.3 Million
Description: PG&E is conducting an Emerging Technologies field assessment to evaluate gross energy savings and effectiveness of EE facilitating features in multiple smart thermostats—Nest, EcoBee3 and Radio Thermostat of America CT50 with EnergyHub service provider—with focus on learning/optimization software, occupancy sensing and geo-location. Behavioral messaging and DR are out of scope. Smart thermostats were professionally installed at no cost to 2,207 residential customers in the North Valley, Stockton and Fresno areas in 2015. Both billing data and manufacturer thermostat usage data is being collected over the 24-month monitoring period and used for analysis. Funding Source: PG&E funded this project using funds authorized under the 2013-2015 EE Program as part of Emerging Technology activities. Status: The project's monitoring and reporting period has been extended to the fall of 2017 in order to capture an additional heating and cooling season. In December 2016, a report providing an analysis of the first year's results was posted to the Emerging Technologies Coordinating Council (ETCC) website (http://www.etcc-ca.com/reports/smart-thermostat-study). All three thermostats achieved annual electric savings ranging from 4-5 percent. One of the thermostats tested also achieved annual gas savings. An updated report will be produced in Q4 2017 that will include an analysis of the second year's performance and the results of a survey of the study participants. Benefits Description: PG&E leveraged key learnings from this study to add smart thermostats to the EE portfolio in June 2017. Benefit Category: The latest generation of Smart Thermostat products offers customers easier and more convenient ways to manage their heating, ventilation and air conditioning with improved functionality and integration to other connected devices. Moreover, smart thermostat as the first connected system in line is a way to enable customers to have insight and control over their energy usage pattern.	

2.5. Distribution Automation and Reliability Projects

Projects in the Distribution Automation and Reliability category provide capabilities and associated technology enablement to monitor and control the electric distribution system. PG&E continues to focus on technology capabilities to increase the visibility and control enabled by Substation SCADA in the distribution system, continues to deploy FLISR technology projects first introduced by the Cornerstone project, implemented technologies to support the effective consolidation of Distribution Control Centers, and piloted and deployed Smart Grid technologies to improve distribution performance and outage response.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2016 through June 30, 2017 time period, unless otherwise noted.

Distribution Substation Supervisory Control and Data Acquisition (SCADA) Program	Approximate Cost Over Reporting Period: $51.6 Million

Description: The Distribution SCADA Program focuses on increasing SCADA penetration and improving reliability for PG&E customers. This program aided in the consolidation of PG&E's Distribution Control Centers, which was completed in 2016. PG&E's goal is to achieve 100 percent visibility and control of all critical distribution substation breakers over the next few years, adding or replacing SCADA for approximately 393 substations and approximately 1,107 breakers.

Funding Source: This project is funded under PG&E's 2011, 2014 and 2017 GRC.

Status: This project is in progress. PG&E anticipates the conclusion of this project in December 2019. Implementation of this project began on March 2011. This project has upgraded or replaced SCADA in 248 substations and added SCADA on 878 breakers between 2011 through June 2017.

Benefits Description: Increasing SCADA penetration enables improvements in reliability, grid planning, and operations.

Benefit Category: Smart Utility – PG&E's goal of 100 percent visibility using SCADA is expected to reduce outage time, personnel travel, and operations time managing the system. Improved SCADA visibility also provides data to better operate, plan and design the distribution system.

Battery Energy Storage System (BESS) Demonstration Projects	For More Information on EPIC Pilots, Refer to 'Electric Program Investment Charge (EPIC) Program' Box

Description: In these projects, PG&E utilizes EPIC Projects Energy Storage for Market and Distribution Operations with the benefit of gaining "real world" experience and data from participation in the CAISO market (EPIC 1.01) and using energy storage to mitigate overload conditions on substation equipment (EPIC 1.02).

EPIC Project 1.01 uses two Sodium Sulfur (NaS) battery sites to gain "real world" experience and data from participation in the CAISO's new Non-Generator Resource market model created specifically for Limited Energy Storage Resources such as batteries. The project concluded in September 2016 and developed and deployed an automated communications and control solution to enable battery resources to automatically respond to CAISO market awards and thus make full use of their fast-response functionalities. Based on the data collected, the project also quantified financial performance from participation in CAISO markets.

EPIC Project 1.02 deployed a 0.5MW/2 MWh Li-Ion battery system to demonstrate energy storage as a potential upgrade deferral resource on the distribution system by deploying a system to address a substation overload condition.

Funding Source: The NaS batteries used by EPIC 1.01 were included for cost recovery in the GRC, and the additional functionality tested for market participation was subsequently approved as an EPIC project. Project 1.02 is EPIC funded.

Status: EPIC 1.01 was closed out in September 2016. EPIC 1.02 is in progress – PG&E deployed the facility in fall 2016 and the system was brought online in January 2017. The system has been operational over the spring and summer months with data collection ongoing and a project close out expected in Q3 2017.

Benefit Description: EPIC 1.01, Energy Storage for Market Operations has significantly improved PG&E's capabilities in operating Energy Storage in the CAISO market. The project set up the Information Technology infrastructure necessary for automated bidding and has methodically explored the use of Vaca and Yerba Buena BESS for providing Energy and Ancillary Services in the CAISO markets. EPIC 1.02 has demonstrated how BESSs can be successfully used on the distribution grid to address overload conditions.

Benefit Category: Smart Market and Smart Utility – PG&E is testing the operational capabilities of grid-scale storage batteries to better understand the benefits to the utility of integrating storage in the overall supply market and distribution system.

Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)	**Approximate Cost Over Reporting Period: $8.9 Million**

Description: This project continues the installation of FLISR systems work that was funded in the Cornerstone D.10-06-048. Smart Grid FLISR will expand the implementation of the FLISR system to approximately 100 circuits per year across the PG&E system to improve customer service reliability.

Funding Source: This project is funded in PG&E's 2017 GRC.

Status: This project has been approved. The Smart Grid FLISR project has begun in 2014 and is expected to continue through 2019.

Benefit Description: When installed, FLISR can reduce the impact of outages by quickly opening and closing automated switches to reduce what may have been a one- to two-hour outage to less than five minutes.

Benefit Category: Smart Utility – the Smart Grid FLISR project improves customer service reliability, provides RT load and voltage data which supports distribution operations and DER/distribution resource integration.

Install Smart Grid Line Sensors Pilot	**Approximate Cost Over Reporting Period: $1.4 Million**

Description: This objective of the project was to pilot how line sensors can: (1) provide more accurate information about the fault location area, allow faster outage restoration by reducing outage response time, and improve customer satisfaction; (2) 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 (3) provide more accurate current flow information to engineers to support better planning of the distribution system rather than relying exclusively on models.

Funding Source: This project was funded under Smart Grid Pilot Deployment Project (D.13-03-032; A.11-11-017).

Status: This pilot project is completed. Installations include both overhead and underground distribution lines. This pilot project began in August 2013 and ended in December 2016. The full final close out report, including project activities and key findings, can be found in Advice Letter 4990-E (https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4990-E.pdf).

PG&E is continuing to operate line sensors and use their data (loading and fault details) to assist in improved outage restoration, load monitoring, and service planning. The CPUC approved this project in March 2013 (D.13-03-032; A.11-11-017). PG&E is also exploring further expansion of the line sensors implementation.

Benefit Description: This pilot project demonstrated safety, reliability, and operational benefits through reducing outage time and improving system operations and planning. This project is expected to deliver the following benefits:

- Customer Cost Savings: reduced operations and maintenance (O&M) from more efficient outage response and restoration; and
- Reliability Benefits: improved Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI).

A forecast of these potential benefits was submitted as part of A.11-11-017. PG&E has also submitted a final status report in compliance with OP 9 of D.13-03-032.

Benefit Category: Smart Utility – The Smart Grid Line Sensor project improves reliability and increases the capability of the distribution system for operations and planning engineering personnel to operate and effectively run the distribution system.

Voltage and Reactive Power (Volt/Var) Optimization System Pilot	Approximate Cost Over Reporting Period: $3.5 Million

Description: This project piloted a voltage and reactive power (Volt/Var) optimization technology to evaluate the technology's 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). VVO is a software-based solution that analyzes grid conditions, determines the device-level adjustments necessary to regulate voltage, and communicates coordinated commands to grid devices in real time. In essence, VVO control systems act as a centralized voltage and reactive power control "brain" of the electric distribution system, for evaluating and signaling the actions needed for better voltage and reactive power regulation. This project will also demonstrate the benefit of this technology in managing voltage with higher levels of DER penetration.

Funding Source: This project is funded under Smart Grid Pilot Deployment Project (D.13-03-032; A.11-11-017).

Status: The CPUC approved this project in March 2013, it began in August 2013 and concluded in December 2016. The project is presently in the Phase 2: Field Trial phase. The full final close out report, including project activities and key findings, can be found in Advice Letter 4990-E (https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4990-E.pdf).

Over the multi-year pilot, PG&E tested a set of VVO solutions in a laboratory environment and then field-trialed promising solutions on 14 distribution circuits in PG&E's Fresno Division. Through executing the pilot, PG&E gained information on VVO implementation, forecasting benefits and costs associated with a deployment of VVO, and how other anticipated grid technology advancements (e.g., adoption of Smart Inverters by customers and Advanced Distribution Management Systems by utilities) can influence the value proposition and cost-effectiveness of VVO. PG&E also collaborated with a Smart Inverter aggregator to drive the early adoption of Smart Inverters at 12 customer locations on Woodward Bank 2. Through this pilot, PG&E became one of the first U.S. utilities to operate VVO and Smart Inverters on the same circuits. The Smart Inverter field trial demonstrated that Smart Inverters can adjust customer voltages using autonomous power factor and Volt-VAR curve functions, and thus can potentially improve VVO's ability to deliver cost-effective Conservation of Voltage Reduction (CVR).

The project found that a VVO deployment to approximately 170 distribution banks (510 circuits) is cost-effective at this point, but that the value proposition of a VVO deployment would improve after PG&E integrates Distribution Management System (DMS) with Distribution SCADA (through, for example, an Advanced DMS). By deferring the deployment of VVO until after the DMS-SCADA integration, PG&E can continue to determine methods to deploy VVO in the most cost-effective manner.

Benefit Description: VVO has three main benefits streams: customer energy usage efficiencies through CVR; enablement of DER Penetration; and enhancement of Grid Monitoring. However, only CVR benefits are tangible enough to be economically valued at this time. The project found that for the feeder banks that represent high-value targets for VVO implementation, VVO could deliver an Average Voltage Reduction at CAISO Peak Demand of 1.6 percent (i.e., customers would experience no change to their end-user experience, but would consume 1.6 percent less electricity).

Benefit Category: Smart Utility – The Volt/Var Optimization project seeks to improve the operating efficiency of distribution circuits and customer equipment by managing the voltage and power factor devices, improving the overall operating efficiency of the distribution circuit and voltage at the customer metering point. Additionally, managing the distribution voltage and power factor reduces the need for generation which in turn reduces GHG emissions.

Detect and Locate Faulted Circuit Conditions Pilot	**Approximate Cost Over Reporting Period:** **$2.6 Million**

Description: This project installed and evaluated a fault-finding software system and systems that assist in more precisely locating failed equipment that caused an outage and determined if there are additional benefits of providing a more accurate location to utility first responders to outages.

Funding Source: This project was funded under Smart Grid Pilot Deployment Project (D.13-03-032; A.11-11-017).

Status: The project concluded at the end of 2016. Some of the findings of the pilot, including isolation of back fed wire down conditions, will continue to be pursued in a future project. The full final close out report, including project activities and key findings, can be found in AL 4990-E (https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4990-E.pdf).

Benefit Description: This pilot project should demonstrate safety, reliability, and operational benefits through reducing outage time and improving system operations and planning. This project is expected to deliver the following benefits:

- Customer Cost Savings: reduced O&M from more efficient outage response and restoration
- Reliability Benefits: improved CAIDI and SAIDI

A forecast of these potential benefits was submitted as part of A.11-11-017. PG&E has also submitted a final status report, in compliance with OP 9 of D.13-03-032.

Benefit Category: Smart Utility – The Smart Grid Detect and Locate Faulted Circuit Conditions project can improve reliability by improving information to find the likely location of the damaged equipment that caused the distribution outage. The distribution operations personnel will be better equipped to operate and efficiently run the distribution system. Additionally, this project explored enhancing the utilities ability to locate and mitigate high impedance faults.

2.6. Transmission Automation and Reliability Projects

Projects included in the Transmission Automation and Reliability category provide capabilities and associated technology enablement to monitor and control the electric transmission system. Over the past year, PG&E has focused on technology capabilities to improve wide-area monitoring, protection, and control enabled by SCADA in the transmission system, equip operators with the tools necessary to enhance bulk system reliability in coordination with the CAISO and neighboring utilities, and pilot and deploy digital substation technology and other Smart Grid technologies.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2016 through June 30, 2017 time period, unless otherwise noted.

Compressed Air Energy Storage (CAES) Demonstration Project	**Approximate Cost Over Reporting Period:** **$0.2 Million**
Description: The purpose of this demonstration project was to determine the technical and economic feasibility of an approximately 300 MW CAES plant using a porous rock structure for up to 10 hours of air storage at a location within California. CAES technology consists of compressing air into an underground porous rock formation during periods of excess generation and then releasing the stored air to generate electricity during periods of peak demand. Funding Source: The project is funded under the Department of Energy (DOE)/American Recovery and Reinvestment Act grant of $25 million, with matching funds approved by the CPUC and CEC of $24 million and $1 million, respectively. Status: This project is complete with a pending release of the final report. The project started in January 2012 and the final report is expected to be completed by fall 2017. PG&E selected two reservoirs for core extraction and analysis. Preliminary core analysis showed that both sites have the permeability and porosity suitable for a CAES project. One of the sites was chosen as the preferred site for the air injection/withdrawal test. The DOE drafted an Environmental Assessment for the preferred site as part of its National Environmental Policy Act review; the DOE issued a Finding of No Significant Impact in May 2014 which allowed the project to move forward with ground disturbance activities associated with the air injection test. PG&E also prepared and submitted an Underground Injection Control permit application to the U.S. Environmental Protection Agency; this permit, which was required prior to construction of the injection/withdrawal well as part of the air injection test, was issued to PG&E on August 20, 2014. PG&E drilled and completed the injection/withdrawal well in Q4 of 2014 and the construction of the air compression test facility in Q1 of 2015. Testing commenced on February 14, 2015, with the injection and withdrawal of approximately 550 million standard cubic feet of oxygen-depleted and ambient air to replicate the operation of a full scale CAES facility. The test results were analyzed and used to calibrate a reservoir air flow model for the conceptual design of a commercial facility. The site was substantially decommissioned by June 30, 2015. A Request for Offers (RFO) for third-party bids to build, own, and operate a CAES facility was released in October 2015 and initial bids were received by June 1, 2016. PG&E evaluated the bids and determined that they were not competitive with the executed storage contracts from	

PG&E's 2014 Storage RFO. The CAES RFO was therefore closed on August 3, 2016. The final report is planned for release by fall 2017.

Benefit Description: If demonstrated to be economically and technologically viable, CAES technology could facilitate the integration of renewable generators and help attain clean energy policy goals.

Benefit Category: Smart Market – This project evaluated the feasibility of a large energy storage facility that could be used to manage renewables and other generation.

Transmission Substation SCADA Program	**Approximate Cost Over Reporting Period:** **$27.4 Million**

Description: Under the Transmission Substation SCADA Program, PG&E is in the process of installing new SCADA on the transmission system to provide PG&E's Electric Operations and the CAISO with full visibility into the transmission system, significantly improving efficiency and operational flexibility. PG&E's current goal is to achieve 100 percent visibility and control of all transmission substations by 2019, adding or replacing SCADA for approximately 230 substations and approximately 673 breakers.

Funding Source: This project is funded under PG&E's Transmission Owner (TO) cases.

Status: This project is currently in progress. The project started in July 2010 and is expected to be completed in December 2019. PG&E has added or replaced SCADA at 205 substations and 646 breakers from 2010 through June 2017.

Benefit Description: Increasing SCADA penetration enables improvements in reliability, grid planning, and operations.

Benefit Category: Smart Utility – PG&E's goal of 100 percent visibility using SCADA is expected to reduce outage time, personnel travel and operations time managing the system and provide data to better operate and plan the transmission system.

Modular Protection Automation and Control (MPAC) Installation Program	**Approximate Cost Over Reporting Period:** **$55 Million**

Description: The multi-year MPAC Program aims to deploy pre-engineered, fabricated, and standardized control buildings in transmission substations. These activities are performed in an integrated manner with other PG&E projects such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.

Funding Source: This project is funded under PG&E's TO cases.

Status: This project is currently in progress. This is an ongoing program, and doesn't have a defined end date. The project began in 2005. PG&E has installed and completed 108 MPAC buildings.

Benefits Description: The program will help improve reliability of the transmission system by replacing aging infrastructure and

modernizing facilities. Over the past year, the MPAC Installation Program has avoided $3.9 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $55 million. Benefit Category: The program is a Smart Utility project designed to improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities.

Synchrophasor Project Realization	**Approximate Cost Over Reporting Period:** **$1.8 Million**
Description: Synchrophasor Technology Realization project will build on the foundation of the original PG&E Synchrophasor Investment project, to provide additional functionality to the Energy Management System (EMS) and integration into RT operations. The initial Synchrophasor Project allowed PG&E (and others within Western Electricity Coordinating Council (WECC)) to install the technology. Data flow into control centers has been enhanced and several use cases for transmission system operation have been implemented. Examples include, post event analysis, phase angle delta monitoring, model validation, and wide-area monitoring. Funding Source: This project is funded primarily under PG&E's TO cases. Status: Active. Communication protocol and transport layer enhancements underway to support data availability and data quality. Synchrophasor test lab completed. Working with PeakRC and the CAISO to improve Synchrophasor data sharing capability. Benefit Description: Synchrophasor technology provides high resolution grid measurement and more accurate and synchronized measurements in real-time. Benefits include: • Improvements in PG&E' system models (the basis for the EMS used by Operators) – Accurate model allows identifying true system constraints (voltage, system instability, thermal), improving transmission system performance, and evaluating true limits due to better results for on-line EMS applications supporting state estimation • More accurate Control Center understanding of the state of the Grid (Situational Awareness) • Faster operator alerts and improved visibility of the fast, dynamic grid conditions • Prompt identification of un-damped grid oscillations to prevent outages • Quick identification of the location of a grid disturbance for faster response • More cohesive system restoration amongst transmission owners and reliability coordinators Benefit Category: System Reliability and Operational Efficiency	

2.7. Asset Management and Operational Efficiency Projects

Projects included in the Asset Management and Operational Efficiency category provide capabilities and associated technology enablement to track and manage asset information (e.g., location, maintenance history, specifications/characteristics), as well as assess and plan asset maintenance, replacement, and capacity enhancements. Over the past year, PG&E has focused on technology capabilities to leverage industry-standard technologies to capture and provide access to accurate, traceable, and verifiable asset information for all stakeholders to support the Electric Operations business.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2016 through June 30, 2017 time period, unless otherwise noted.

Network Supervisory Control and Data Acquisition (SCADA) Monitoring Project	**Approximate Cost Over Reporting Period:** **$7.7 Million**
<u>Description</u>: The project is installing new monitoring and control systems on the downtown San Francisco and Oakland secondary network systems including full remote control on network protectors (including remote setting of relays), and primary switches. The monitoring itself includes voltages, currents, temperature, oil level, and chamber pressures. For vaults, the monitoring system includes SCADA battery, water detection and may include others such as distributed generation monitoring depending on future needs and feasibility. Real-time data collected from the equipment is used for triggering of alarms, and for equipment condition assessment as part of the Condition-Based Maintenance (CBM) system for O&M activities. The data is also used for asset management decisions on maintenance and replacement of network equipment. The new SCADA system has remote operating capabilities that include network protector open/close and station transfer trip of the network protectors for feeder clearances. <u>Funding Source</u>: This project is funded by PG&E's 2014 and 2017 GRC filings. <u>Status</u>: This project is currently in progress. PG&E has a total of 12 network groups. Four network groups are complete (Z-34-1, Z-34-2, Z-1, Y-4) with two additional network groups (Y-3, Y-2) in progress. These completed network groups have been added to the PI Historian system which is the data accumulator for all of the SCADA information. This data in turn is coupled with the CBM system described above which allows PG&E to transition from time based to condition based replacement and maintenance. This results in a safer system while at the same time generating savings through deferring work until the condition of the equipment warrants. <u>Benefit Description</u>: The new control features included as part of this project will improve personnel safety and overall system operability. <u>Benefit Category</u>: Smart Utility – This project provides information for PG&E to better manage its assets and make informed maintenance, repair and upgrade decisions.	

Smart Grid Short-Term Demand Forecasting Pilot Project	Approximate Cost Over Reporting Period: $1.0 Million
Description: 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 for retail load. The Project will follow a three-phase approach to analyze, build, and pilot the systems that incorporate more granular sources of data for local pilot areas within PG&E's service territory. Funding Source: This project is funded under Smart Grid Pilot Deployment Project D.13-03-032. Status: The CPUC approved this project in March 2013 (AL 4227-E, D.13-03-032; A.11-11-017) and the continuation of the project to Phase 2 and 3 (ALs 4429-E and 4770-E, respectively). In Phase 1, PG&E identified the local areas and data sources to test the new forecasting methodology. In Phase 2, PG&E built the infrastructure and systems to process the new granular data sources into a central repository for input into the demand forecasting model for the local pilot areas. In Phase 3, PG&E forecasted hourly loads for the local areas on 7 x 24 basis, analyzed the model performance, and evaluated the new forecasting methodology for systemwide deployment. The project concluded at the end of December 2016, an advice letter with the final project report was submitted to the CPUC for review. Benefit Description: This pilot project provided insight on whether more granular sources of data can improve the accuracy of PG&E's demand forecast within the selected areas and if the implementation to PG&E's entire service area would be cost effective. Benefit Category: Smart Market and Smart Utility – This project uses SCADA data and SmartMeter™ usage data to determine if there is an improvement to the accuracy of PG&E's short-term electric demand forecasts to meet PG&E's retail load obligations.	

2.8. Security (Physical and Cyber) Projects

Since the publication of the Smart Grid Deployment Plan, PG&E completed the Advanced Detection and Analysis of Persistent Threats (ADAPT) cybersecurity project that was primarily focused on increasing the Utility's capability to effectively anticipate, prevent, and respond to a new and emerging class of cyber and physical threats. Following the conclusion of the ADAPT project, PG&E has undertaken the implementation of a second project, the Identity and Access Management (IAM) project. This is a multi-year investment focused on improving PG&E's core access control capabilities. Additional detail on this project has been provided in the following section, and discussion of PG&E's overall Cybersecurity Risk Management Program is provided in Sections 2.12-2.16 of this report.

The cybersecurity projects have multiple goals and provide regulatory compliance benefits (SOX, NERC Critical Infrastructure Protection (CIP), and other standards and regulations), significant risk reduction benefits, and alignment to PG&E's Risk Management Framework (RMF) as described later in this document.

Identity and Access Management Program	**Approximate Cost Over Reporting Period:** **$11.54 Million**

Description: The IAM Program is a multi-year, multi-project enterprise level investment that will strengthen authorized PG&E system access controls and reduce the risk of unauthorized access. The program will improve centralized access control to key PG&E systems, provide role-based access control to those systems, centralize the authoritative source for identity attributes of authorized individuals, and provide enhanced auditing capabilities to achieve enterprise wide visibility and control of employee access to systems. Through the IAM Program, PG&E will implement key technologies and services in the areas of identity management, credential administration, provisioning, entitlements, access management, and audit and compliance.

Funding Source: This program is funded in PG&E's 2011, 2014 and 2017 GRCs, and TO funds for the NERC CIP Program.

Status: The program started in March 2012, is ongoing, and remains in progress.

Benefit Description: As of July 2017, PG&E has decreased the risk of unauthorized physical and logical access through: automated creation of network login credentials for approved and authorized users; automated removal of access from up to 231 separate facility access control systems for decommissioned users; centralized server access provisioning/de-provisioning, monitoring and reporting; improved governance processes for enterprise user access functions contributing to a reduction in Segregation of Duties violations by 91 percent; deployed controls to restrict and better monitor privileged accounts; deployed a centralized logical and physical access management portal called My Access; and retired the legacy provisioning system for SOX applications. The program continues to expand by creating controls for cross-layer segregations of duties, institute role-based access control for critical functions, integrate additional applications to the platform including key regulatory systems (e.g., SOX, NERC CIP, and Customer Energy Usage Data systems), update legacy technology to support customer authentication to externally facing PG&E applications, and strengthen controls for shared administrative and service accounts.

Benefit Category: Engaged Consumer, Smart Market, and Smart Utility – The IAM Program, enhances controls across the entire PG&E infrastructure and is not limited to the Smart Grid. Each of the Engaged Consumer, Smart Market, and Smart Utility areas benefit from these improved controls that protect key processes and systems across the enterprise. For example, the infrastructure that allows customers to log in to PG&E's My Energy will be enhanced with increased security and control mechanisms to validate that only customers and their approved designees can access customer energy information online.

2.9. Integrated and Cross-Cutting Systems Projects

Integrated and cross-cutting systems refer to projects that support multiple smart grid domains, such as grid communications, application platforms, data management and analytics, advanced technology testing, and workforce development and technology training. An integrated approach for this type of projects will ensure that investments are managed efficiently while creating the platform to deliver a stream of benefits across the IOU operations and to customers.

Integrated communications systems will provide solutions to connect and enable sensors, metering, maintenance, and grid asset control networks. In the mid- to long-term, integrated and cross cutting systems would enable information exchange with the IOU, service partners and customers using secure networks. Data management and analytics projects will improve the IOU's ability to utilize vast new streams of data from T&D automation and SmartMeter™ devices for improved operations, planning, asset management, and enhanced services for customers.

Advanced technology testing and standards certification are a foundational capability for the IOUs to evaluate new devices from vendors and test them in a demonstration environment prior to deployment onto the electric system. This reduces the risks associated with new technology projects, and helps the IOUs maximize technology performance and interoperability prior to deployment.

Workforce development and advanced technology training enables the successful deployment of new technologies, ensuring that the IOUs' workforces are prepared to make use of new technologies.

The integrated and cross-cutting systems group is driven by several state and federal laws and regulatory orders including SB 17, Energy Independence and Security Act, CPUC D.10-06-047, AB 32 and Executive Order S-305, SB 078 and SB X1-2.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2016 through June 30, 2017 time period, unless otherwise noted.

Telecommunications Architecture	Approximate Cost Over Reporting Period: $5.7 Million

Description: Telecommunications Architecture allows PG&E to meet near-term and long-term telecommunications needs by developing and implementing a multi-tier, multi-service telecommunications infrastructure architecture, consisting of a core and an edge network. Smart Grid projects require an exponential increase in the ability for customers, markets and utilities to securely and reliably communicate on a near RT basis. New communication models include customer to utility, customer to market, and smart "equipment to equipment." PG&E's telecommunication infrastructure must be enhanced to facilitate this increased communications and also developed in a systematic, economic manner that allows for re-use of communications infrastructure.

A blend of technologies will be needed to address the diverse performance needs and geography of the PG&E service territory. Increased SCADA density, Phasor Measurement Units (PMU), cyber security, and network management requirements will drive capacity, latency, and quality of service requirements that must be built into future networks.

Funding Source: This project is being funded in PG&E's 2011, 2014 and 2017 GRCs.

Status: This project is currently in progress and is expected to be completed in 2017. PG&E has completed implementation of the core and aggregation layer of the Multi-Protocol Label Switching network and has begun the network consolidation. Multiple Virtual Routing and Forwarding Domains have been constructed enhancing security and availability of critical applications. Pilot installations of wireless edge technologies have begun to verify cost models associated with the technology and ensure system meets desired increases in capacity and coverage, and reductions in latency.

Benefits Description: Benefits are estimated at $10 million in lifecycle asset replacement avoidance.

Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.

California Energy Systems for the 21st Century (CES-21) Program	Approximate Cost Over Reporting Period: $4.0 Million

Description: The CES-21 Program is a public-private collaborative research and development program between PG&E, Southern California Edison Company, San Diego Gas & Electric Company, and LLNL. The CES-21 Program is divided into two projects which research challenges of cybersecurity and the applicability of grid flexibility metrics as the grid becomes more dynamic and complex.

The CES-21 Program utilizes a team of technical experts from the Joint Utilities and LLNL, who leverage and extend ongoing research in grid modelling and cybersecurity. LLNL will combine data integration with advanced modeling, simulation, and analytical tools to provide problem solving and planning necessary for the challenges of grid integration. On April 25, 2014, the three utilities filed a joint Advice Letter (PG&E AL 4402-E) requesting approval for two research projects and the Cooperative Research and Development Agreement (CRADA), which was approved in October 2014.

Funding Source: In D.14-03-029, which modified D.12-12-031 to comply with SB 96, the Commission authorized the three utilities to recover up to $35 million over five years for the CES-21 Program.

Status: The CPUC approved the Advice Letter (PG&E AL 4402-E) and CRADA in October 2014, allowing the IOUs and LLNL to initiate the cybersecurity and grid integration projects at the beginning of 2015. Please note that the CES-21 initiative files a comprehensive annual report. Highlights of the projects' statuses includes:

- The Cybersecurity project is in the Build/Test phase and will complete by the end of 2019. Initial successes have included the development of a converged grid/network modeling engine that successfully simulated a cyberattack causing physical equipment damage, and the CES-21-driven update to the threat encoding language STIX, which is a global cyber standard managed by industry group OASIS.
- The Grid Integration Flexibility Metrics project is in Close Out phase and will complete by end of 2017. It is socializing the results of its modeling through the stakeholders of the Commission's IRP proceeding.

Benefit Description: The CES-21 Program has the potential to deliver significant benefits to California's electric customers. Cyberattacks pose an existential threat to delivering reliable electric service to California customers. Automated response capabilities may reduce the number of outages, minimize their impact, and improve response and recovery times. The Grid Integration Flexibility Metrics project may reduce operating and capital costs and improve reliability by reducing uncertainty around appropriate metrics to gauge reliability, operating flexibility, and the adequacy of planned resources as adoption of intermittent renewables increases.

Benefit Category: Smart Markets and Smart Utility – Cross-cutting initiatives apply across all various segments.

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $21.4 Million

Description: The EPIC program provides funding to demonstrate promising new technologies and determine their applicability to address future challenges. EPIC funded projects that are executed by PG&E are focused on four key areas: Renewables and DER Integration; Grid Modernization and Optimization; Customer Service and Enablement; and Cross-Cutting and Foundational Strategy. The program is currently authorized at the state level for three cycles, each cycle is three years:

- EPIC 1 (2014-2016): PG&E's application included 26 potential projects; filing can be found at www.pge.com/epic
- EPIC 2 (2015-2017): PG&E's application included 30 potential projects, of which 17 have been pursued. [same]
- EPIC 3 (2018-2020): PG&E submitted its application for 41 projects in May 2017. [same]

Project status: Information about EPIC 1 and 2 can be found in PG&E's EPIC 2016 Annual Report, which was filed on February 28, 2017, and can be found on PG&E's website at www.pge.com/epic. All final reports for projects that are complete are publically available at the same site.

Funding Source: The EPIC 1 Program is authorized via D.12-05-037, and the EPIC 2 Program via D.15-04-020. The Commission authorized the three IOUs to collect funding for the EPIC Program in the total amount of $162 million annually beginning January 1, 2013 and continuing through December 31, 2020. The total collection amount was adjusted on January 1, 2015 to $169.9 million annually, commensurated with the average change in the Consumer Price Index, and this adjustment will occur again on January 1, 2018. PG&E's share is 50.1 percent or approximately $81 million dollars annually. PG&E sends 80 percent of these funds to the CEC, for their use in addressing EPIC goals. The remaining 20 percent is retained by PG&E to run technology demonstrations. Note: only the PG&E expended costs are reflected in the July 2016 – June 2017 number above (i.e., no CEC funds are included).

Status:

- **EPIC 1:** As of June 2016, PG&E had closed 4 projects from EPIC 1; by the end of January 2017, an additional **12** projects had closed. Highlights of completed projects include:
  - *EPIC 1.09C – Test New Remote Monitoring and Control Systems for T&D Assets*
    Demonstrated a new device technology, Distributed Series Reactors, that are deployed directly onto transmission conductors to detect potential overloads and increase line impedance to shift load. These devices can mitigation overloads on transmissions lines, and potentially delay costly reconductoring projects.
  - *EPIC 1.18 – Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information*
    Project evaluated disaggregation vendors' ability to itemize monthly appliance-level usage for residential customers. If successful, this would allow PG&E to provide customers with actionable information about which appliances are the key drivers of their electrical service costs. The demonstration found that the algorithmic maturity of these vendors does not meet PG&E's threshold for use in customer outreach. While the demonstration did not yield a technology ready for wider adoption, this project represents how PG&E can save customer dollars by testing available technologies on a small scale, before investing in a territory-wide service.

- *EPIC 1.19 - Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform*
  Successfully demonstrated new ways to leverage PG&E's AMI, such as using meter data to: collect power quality data and potentially enable proactive responses customer voltage issues; connect difficult-to-reach meters to the AMI network to potentially reduce manual meter reading costs; and identify 'Line Side Tap' scenarios to reduce energy diversion.

- **EPIC 2:** Between July 2016 and June 2017, the first EPIC 2 project closed out at PG&E (EPIC 2.04 – Distributed Generation Monitoring and Voltage Tracking). More than a dozen are currently in flight, and technology highlights include:
  - *EPIC 2.04 – DG Monitoring and Voltage Tracking (closed)*
    This project demonstrated an algorithmic process to analyze new data sources (including SmartMeter™ devices and databases of solar irradiance) to predict the likelihood that a Rule 2 voltage violation was caused by distributed solar generation. Solar energy is by nature intermittent, and ebbs and surges of generation can change the voltage for neighboring, downstream customers. This functionality, if integrated into a larger grid analytics platform, might improve decision making for Power Quality Engineers responding to customer issues.
  - *EPIC 2.10 – Emergency Preparedness Modeling*
    This demonstration seeks to utilize novel artificial intelligence and optimization techniques to provide strategic emergency restoration recommendations based upon damage models and outage information. In addition, this project will incorporate this information along with critical RT data from enterprise systems to develop a Restoration Informatics System. This innovative aggregation may help PG&E better understand the impacts of the natural hazards (number of outages, customers out, and potential length of outages) and ultimately improve resource allocation and prioritization decisions to accelerate service restoration after an emergency event.
  - *EPIC 2.23 - Integrate Demand Side Approaches Into Utility Planning (in flight)*
    Works to incorporate the growing usage of DER into distribution planning tools by developing new customer class load shapes that incorporate DERs, and a methodology for modeling DER deployment uncertainty at the circuit level.

Benefit Description: EPIC technology demonstrations generate key learnings that can help PG&E make informed decisions about wider technology investments that could improve the safety, reliability and affordability of the electric system, but are not designed to deliver benefits at scale by themselves. Select learnings qualify as IP assets that can help the Utility operate more efficiently and reduce customer costs. PG&E is monitoring demonstration projects for new developments that can improve overall operations as well as have the potential to generate incremental IP revenues, which can contribute to reduced costs for customers.

Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.

Workforce Development and Technology Training	Approximate Cost Over Reporting Period: N/A
Description: The evolution of the electric grid includes much more distributed intelligence, i.e., Smart Grid. PG&E supports this evolution by developing training in a wide variety of grid-related topics, all of which include elements of distributed intelligence, and offering them to the general workforce, targeting those who can use the information most effectively. Funding Source: This work is funded through PG&E's GRCs. Status: PG&E is continuing to enhance workforce skills to support a smarter, more integrated grid. Benefit Description: PG&E's training helps develop the skilled workforce necessary to evolve the electrical grid and meet the energy goals of the state of California. Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.	

Supplier Diversity	Approximate Cost Over Reporting Period: N/A
Description: Throughout the process of identifying qualified suppliers to participate in the initial testing and limited pilots, PG&E emphasized the criticality of diverse supplier inclusion. PG&E continues to highlight the importance of education, mentoring and careful planning for the full participation of DBEs as business solution partners and subcontractors over the life of this program. As part of the advance planning and education effort, PG&E provided specific Smart Grid and general business opportunities to DBEs, including: • PG&E's sponsorship of DBE firms in the University of California Advanced Technology Management Institute executive management training for companies poised for growth in emerging technologies like Smart Grid. • PG&E's sponsorship of DBE firms in the UCLA Anderson School of Business, Management Development for Entrepreneurs executive business management training. • DBE supplier development opportunities through PG&E's Technical Assistance Program, which include ISO 9001 and ISO 14001 certification training scholarships, DBE sponsorships to select industry trade shows, invitations to matchmaking events and other educational workshops.	

2.10. Customer Roadmap

In its March 2012 Smart Grid Workshop Report, CPUC Staff requested the following information to be included in the IOUs' Smart Grid Annual Reports:

1. Timeline that connects specific projects with specific marketing and outreach efforts; and
2. Specific steps to overcome roadblocks, as identified in the workshops and included in this report.[8]

As requested by CPUC Staff, PG&E is providing marketing and outreach information using the sample template in Appendix 1 to the Smart Grid Workshop Report as follows:

Timeline: PG&E has adapted the CPUC Staff's template (Appendix 1) to reflect the existing and planned work that is related to the Smart Grid, including approved initiatives in place that meet the customer objectives outlined in SB 17 and D.10-06-047. Since the Marketing, Education, and Outreach proposal in the Smart Grid pilot deployment A.11-11-017 was denied, the only outreach that provides support to the Smart Grid initiative is conducted through funding approvals of individual program and their initiatives as listed in Table 2-1.

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[8] See Smart Grid Workshop Report: Staff Comments and Recommendations, March 1, 2012, p. 10.

Initiative Detail: For each of the project areas identified in the Customer Engagement timeline, PG&E has provided detail on existing or proposed outreach and resources, tools, and rates available to customers in accordance with the proposed template from the Commission's Smart Grid Workshop Report.

Table 2-1 below provides an annual illustration of PG&E's customer engagement timeline.

Customer Engagement Timeline - Table 2-1	2014	2015	2016	2017	2018*
Energy Management Enablement Tools:					
PG&E Online Account Web Tools (including rate comparisons)	X	X	X	X	X
Universal Audit Tools	X	X	X	X	X
Energy Usage Alerts	X	X	X	X	X
Business and Home Energy Reports	X	X	X	X	X
Third-Party Customer Data Access Tools (e.g., green button connect, customer data access)	X	X	X	X	X
SmartMeter™	X				
Electric Program Investment Charge**				X	X
Behind-the-Meter (Customer Premise) Devices:					
SmartAC*	X	X	X	X	
Distributed Generation (Solar Water Heating, Solar PV, etc.)	X	X	X	X	X
Business and Home Area Network; Local Area Network; Smart Thermostat, etc.	X	X	X	X	
Electric Vehicle Supply Equipment*	X	X	X	X	X
Rates Options:					
SmartRate and Related Residential Time Varying Rates*	X	X	X	X	X
Time-of-Use	X	X	X	X	X
Peak Day Pricing	X	X	X	X	X
Electric Vehicle Rates	X	X	X	X	X

* These forecasts are based on the best knowledge PG&E has at the current time; however, future regulatory decisions or other business developments may alter these forecasts.

** Various EPIC pilots have some component of customer outreach/marketing.

2.11. Overview of Customer Engagement Plan

PG&E's had sought approval for a plan to more broadly educate customers on longer-term benefits of Smart Grid technology beyond these immediate offerings, to provide context for future technologies and customer-facing benefits that will be available in the coming years in PG&E's Customer Outreach and Education Pilot. However, since the Outreach proposal in A.11-11-017 was denied, the outreach that supports the Smart Grid initiative can only be conducted through marketing of individual programs if they are approved in new cycles with outreach funds allocated. PG&E's outreach efforts over the reporting period have been focused on meeting goals of each program.

PG&E's effort to ensure that customers have the tools and knowledge to benefit from the Smart Grid have included:

- Customer education on available tools designed to help customers understand their energy use;
- Customer education on choices for rate options and new technology that will help customers manage their energy bills; and
- Communicating with customers through communication methods they prefer, including online and by mail.

2.12. Smart Grid Engagement by Initiative Area

In the following section PG&E describes the customer engagement elements that are promoted or are available to customers for each initiative area identified in Table 2-1 above, as requested by CPUC Staff in its March 1, 2012 Smart Grid Workshop Report.

Enablement Tool: Energy Management*	
Project Description	Marketing, Education and Outreach (ME&O) to educate customers about the various tools available to evaluate and manage their energy use and to develop a more interactive and engaged relationship with PG&E services.
Target Audience	Focused on Residential and SMB Customers.
Sample Message	"PG&E offers a number of ways to help you evaluate your energy use and learn about ways to save energy."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Low engagement category. • There is a low baseline incentive for customers to be interested in incremental savings on their energy statement given the low engagement level of the utility category. • While customers are increasingly interested in digital communications, not all customers prefer communications through online channels.
Strategy to Overcome Roadblocks	• Continue to use a variety of outreach methods to ensure highest penetration possible of relevant and targeted information with residential customers. • Continue to market energy enablement tools. • Demonstrate available energy savings by highlighting SMB customer case studies. • Conduct frequent customer communication, including through the Small Business and residential e-newsletters.

Enablement Tool: Behind the Meter (Customer Premises) Devices*	
Project Description	ME&O to educate customers about available home or businesses devices that: 1) Provide interval energy usage data like SmartMeter™, Home Area Networks (HAN) Local Area Networks (LAN). 2) Allow customers to participate directly in grid operations with tools like SmartAC. 3) Facilitate distributed generation.
Target Audience	Residential and SMB customers.
Sample Message	"PG&E offers devices that provide information to help customers manage energy use or costs."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Concerns about ceding control of customer premises to utility through installed devices, such as SmartAC. • Immediate economic impact (i.e., cost savings) is not always easily seen. • Long payback periods on technology investments can make the Investment unfeasible.

Strategy to Overcome Roadblocks	• Provide customers with factual information about devices, focusing on:
	  ○ The benefits and energy management tools it serves.
	  ○ The potential to positively impact the customer's economic bottom line with cost savings.
	  ○ Positive impact on grid stability and reliability.
	• Continue to market availability of customer premise device rebates.

Rate Options*	
Project Description	ME&O to educate customers about rate options. Includes both opt-in and default TOU rate plans for residential customers and default rates for SMB customers.
Target Audience	Residential and SMB customers.
Sample Message	"Rate options offer customers new ways to conserve energy and to choose the rate that is best for them."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Lack of customer understanding about how they can benefit financially from various rate options available, rates lack differentiation from a customer's perspective. • TOU and critical peak pricing requires action from the customer on event days and peak hours are not currently aligned. • Changes to rate structures for residential and businesses.
Strategy to Overcome Roadblocks	• Sustained, ongoing outreach about default rates for both Residential and SMB (prior to and after default) and how to participate in opt-in residential rates. • Late hours of TOU rates are a non-starter for many residential customers. • Provide customers examples of how to benefit from rate options on peak event days and how to prepare for an event day, including developing an action plan. • Provide education to encourage customers to shift the majority, but not all, of their energy usage to off-peak hours. • For SMB customers, this is achieved with education about the PDP Program both before and after their automatic transition onto the rate, so that they understand how PDP works, what the potential benefits are for the customer, and what specific actions a customer should take on an event day to be successful. • For residential customers, a focus on educating customers on the choices and control they have over their bill by familiarizing customers with different rate options, tools, programs and tips that can help them better manage their energy use.

* Not all current engagement roadblocks and strategies to overcome those roadblocks may apply to every program, tool, or service listed in the charts in 2.9

2.13. Key Risks Overview

As part of the continuous review of its key risks, PG&E has concluded that there has been no appreciable change to those risks over the past year.

PG&E initially laid out its strategy for measuring, managing and mitigating both cybersecurity technology risks and physical security risks in its June 2011 Smart Grid Deployment Plan filing. The strategy described in June 2011 highlighted PG&E's fundamental cybersecurity approach at that time. The Utility business continues to evolve. New operational models depend more and more on converged Information and Operations Technologies to perform advanced business functions such as those proposed for the Smart Grid. Many of these functions are automated and will be implemented through information-rich applications or grid automation with "smart" devices. New technologies change the risk and threat landscape. New threats continue to put pressure on and change the risk posture of the Utility requiring more protective measures and safeguards to prevent, detect, respond, and recover in a resilient manner that does not jeopardize the safe, reliable, and cost-effective delivery of energy to customers. PG&E is positioned to address the risks presented by the evolving Utility business and Smart Grid technologies.

2.14. Key Risks and Actions Taken to Address Them

PG&E takes a risk-based, all-hazards approach to protecting the resilience, reliability, and recovery of the computers, control systems, and other digital infrastructure that operates the electric grid. PG&E ensures executive support for cyber and physical risk management activities, and that risks are understood and managed throughout the enterprise. PG&E also maintains collaborative relationships with government, regulatory, and industry bodies to collectively protect the cybersecurity of the bulk electric power system, prioritize assets, address vulnerabilities, manage emerging risks, and maintain open lines of communication.

Since June 2011, PG&E's cybersecurity strategy has matured in numerous ways, one of which is the implementation of a new method for proactively identifying cybersecurity risk through the Risk Assessment Methodology (RAM), which complements existing efforts across the enterprise for managing risk and compliance. PG&E recognizes that focusing solely on compliance management without a holistic cybersecurity risk management approach will not achieve the desired optimal outcome to adequately protect the Utility and the Smart Grid. The RAM provides a new mechanism to identify cybersecurity risks across the enterprise. Another significant milestone is in the maturity of PG&E's overall security strategy, realized by the centralization of the security organization, which both the physical and cybersecurity groups now reside in. From a cybersecurity perspective, physical security is leveraged as part of the overall defense-in-depth strategy; a critical protection layer for the widely distributed systems and devices planned for the evolving Smart Grid.

In 2016, PG&E took several actions to strengthen the security posture of the Smart Grid, including increasing security evaluation, oversight and governance, and implementing more holistic NIST-based assessments. Moving forward, the newly implemented RAM will work in concert with PG&E's annual integrated planning process to identify new cyber risks related to the Smart Grid and plan the necessary actions to address them.

The 2016 consolidation of physical and cyber security into one organization supports an approach to system security in a holistic manner. Now that Corporate Security aligns with cybersecurity strategy, they continue to remain abreast of changes in the regulatory landscape and closely follow all Critical Cyber Assets outlined in the NERC Cyber Security Standards, CIP 006 as well as industry standards from NIST, such as those outlined in the industry guideline NISTIR 7628, Guidelines for Smart Grid Cyber Security.

2.14.1. Managing Cyber Security Risk Through Control Baseline

Controls are the system safeguards that mitigate various types of risk, and PG&E has developed a set of standardized, baseline controls that align to multiple best practice governing bodies and regulations. PG&E has established the following 17 control families as part of its baseline controls which are aligned with the NIST's Cybersecurity Controls Framework:

- Access Control
- Security Awareness and Training
- Audit and Accountability
- Security Assessment and Authorization

- Configuration Management
- Contingency Planning
- Cybersecurity Program
- Identification and Authentication
- Incident Response
- System Maintenance
- Media Protection
- Physical and Environmental Protection
- Security Planning
- Risk Assessment
- System and Services Acquisition
- System and Communications Protection
- System and Information Integrity

These control families provide a baseline for risk measurement and inform controls implementation across people, process, and technology.

2.15. PG&E's Compliance With NERC Security Rules and Other Security Guidelines and Standards as Identified by NIST and Adopted by FERC

PG&E has developed and established formal standards that form the foundation for controls implementation and adherence. Examples of those standards include password management, user access management, information classification, information security, training, and privacy. PG&E's standards leverage industry best practice standards such as NIST. PG&E also participates in industry peer groups to understand changes in technology and regularly updates applicable standards. PG&E has implemented a Guidance Document Management initiative in order to make standards more intuitive and easy to understand. This helps improve compliance with both the spirit and intent of the guidance.

PG&E's RMF enables compliance with multiple state and federal regulations and is aligned to leading industry practices and standards including the following:

- NERC Critical Infrastructure Protection (NERC CIP)
- Industry Guidelines
- Privacy
  - CPUC Privacy D.11-07-056
  - California SB 1476
  - California SB 1386
- SCADA System Security
  - International Electro Technical Commission 62351
- Others
  - International Organization for Standardization/IEC 27000 Series
  - Federal Communication Commission Regulations
  - Sarbanes Oxley
  - Health Insurance Portability and Accountability Act

PG&E participates in multiple forums to ensure that its control design is current, comprehensive and remains in alignment with the standards and industry groups mentioned above. PG&E also engages with external partners related to cybersecurity and cyber risk management, including industry bodies, government-related security forums, and academia.

2.16. Key Risks Conclusion

PG&E continues to improve upon its ability to measure, manage, communicate, and mitigate potential cybersecurity, privacy, and technology risks that could impact the systems that PG&E depends on to deliver safe and reliable electric and gas services to its customers. PG&E's risk management approach is focused on ensuring that risks are well understood at all levels of the Company and that there is executive support for mitigating and managing operational risks, physical security risks as well as cyber security risk. PG&E's risk management efforts are focused on continuous improvement to effectively predict and proactively manage risk by integrating risk management strategies, plans and practices into everyday business activities.

CHAPTER 3

SMART GRID METRICS AND GOALS

3. Smart Grid Metrics and Goals

In this section, PG&E provides an update on the consensus Smart Grid metrics approved by the Commission in D.12-04-025. PG&E continues to support the Commission's position that these consensus metrics will provide parties and the Commission with information that will allow for better understanding of PG&E's Smart Grid investments and provide the foundation for moving forward with Smart Grid investments. This year, PG&E has added metrics around Advanced Metering Infrastructure, per CPUC request.

3.1. Customer/Advanced Metering Infrastructure Metrics

Metric 1: Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters.

Number of PG&E Advanced Meter Malfunctions Where Customer Electric Service is Disrupted; Percentage of Total Installed Advanced Meters	
Metric	Value
Number of Meter Malfunctions	148 meters
Percentage of Total Meters	0.00277%
Note: Reporting date: July 1, 2016 through June 30, 2017	

Metric 1a,1b, 1c, 1d:

Other Advanced Meter Malfunctions Metrics	
Metric	Value
a. Number of SmartMeter™ Devices Installed	5,333,221
b. Number of Smart Meter™ Devices Activated	5,318,588
c. Number of Opt-Outs	50,905
d. Amount of non-SmartMeter™ Devices and/or Amount of Meters Still Manually Read	117,248
Notes: Cumulative counts as of end of June 2017. The cumulative reporting method is consistent with how PG&E reports SmartMeter™ status in the 2017 Institute for Electric Innovation Survey.	

Metric 2: Load impact in MW of peak load reduction from the summer peak and from winter peak due to smart grid-enabled, utility administered DR programs (in total and by customer class).

Load Impact in MW of Peak Load Reduction From the Summer Peak and From Winter Peak Due to Smart Grid-enabled, Utility Administered Demand Response Programs	
Metric	Value
From the Summer Peak (May 2016 – October 2016)	
Residential	0 MW
Non-Residential < 200 kW	0.8 MW
Non-Residential ≥ 200 kW	15.7 MW
Other (Agricultural)	7.5 MW
Total	23.9 MW
From the Winter Peak (November 2016 – April 2017)	
Residential	0 MW
Non-Residential < 200 kW	0 MW
Non-Residential ≥ 200 kW	0 MW
Other (Agricultural)	0 MW
Total	0 MW
Note: Includes load reduction from DR programs and time-varying rates that is enabled by automated technologies.	

Metric 3: Percentage of DR enabled by AutoDR in each individual DR impact program.

Percentage of PG&E Demand Response Enabled by AutoDR in Each Individual DR Impact Program (2016)	
Metric	Value
Percentage of DR enabled by AutoDR – Demand Bidding Program (DBP)	7%
Percentage of DR enabled by AutoDR – Peak Day Pricing (PDP) Program	2%
Percentage of DR enabled by AutoDR – Capacity Bidding Program (CBP)	3%
Percentage of DR enabled by AutoDR – Aggregator Managed Portfolio (AMP)	7%
Note: Percentage represents the Verified kW load reductions (engineering analysis) available for DR programs in 2016, divided by total DR portfolio kW, with the resulting number multiplied by 100.	

Metric 4: The number and percentage of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, California Alternate Rates for Energy (CARE) status, and climate zone).

Number and Percentage of PG&E Owned Advanced Meters With Consumer Devices With HAN or Comparable Consumer Energy Monitoring or Measurement Devices Registered With PG&E		
Metric	Number	Percentage
Residential	5,033	<1%
Non-Residential < 200 kW	87	<1%
Non-Residential ≥ 200 kW	4	<1%
Other	0	0%
Total	5,126	<1%
CARE	0	0%
Non-CARE	5,126	<1%
Total (CARE and Non-CARE)	5,126	<1%
Climate Zone P	99	<1%
Climate Zone Q	24	<1%
Climate Zone R	176	<1%
Climate Zone S	472	<1%
Climate Zone T	1,171	<1%
Climate Zone V	23	<1%
Climate Zone W	57	<1%
Climate Zone X	3,082	<1%
Climate Zone Y	18	<1%
Climate Zone Z	4	<1%
Total by Climate Zone	5,126	<1%
Note: Percentage is defined as the number of advanced meters with consumer devices with HAN or comparable consumer energy devices registered with the Utility divided by the number of advanced meters installed for the group of concern, with the resulting number multiplied by 100.		

Metric 5: Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE, and by climate zone).

Number and Percentage of Customers on a Time-Variant or Dynamic Pricing Tariff		
Metric	Number	Percentage
Residential	392,650	8%
Non-Residential < 200 kW	526,621	79%
Non-Residential ≥ 200 kW	9,651	1%
Total	928,922	17%
CARE	60,807	5%
Non-CARE	868,115	21%
Total (CARE and Non-CARE)	928,922	17%
Climate Zone P	35,015	19%
Climate Zone Q	1,061	28%
Climate Zone R	123,654	21%
Climate Zone S	177,743	20%
Climate Zone T	178,554	14%
Climate Zone V	10,513	18%
Climate Zone W	59,671	20%
Climate Zone X	332,273	17%
Climate Zone Y	9,667	15%
Climate Zone Z	771	3%
Total by Climate Zone	928,922	17%
Note: Percentage is defined as the number of customers that are on a time-variant or dynamic pricing tariff divided by the number of customers in the group of concern, with the resulting number multiplied by 100.		

Metric 6: Number and percentage of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters; or (2) the functioning of a utility-administered HAN with registered consumer devices.

Number and Percentage of Escalated PG&E Customer Complaints Related to (a) Accuracy, Functioning or Installation of Advanced Meters; or (b) Functioning of a PG&E-Administered Home Area Network With Registered Consumer Devices		
Metric	Number	Percentage
Escalated customer complaints related to the accuracy, functioning or installation of advanced meters	10	0.83%
Escalated customer complaints related to the functioning of a PG&E-administered HAN with registered consumer devices	0	0%
Note: Percentage is defined as the number of escalated complaints related to (1) the accuracy, functioning, or installation of advanced meters; or (2) the functioning of a utility-administered HAN with registered consumer devices divided by the number of escalated complaints in total, with the resulting number multiplied by 100.		

Metric 7: The number and percentage of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, with an explanation for the replacement.

Number and Percentage of Advanced Meters Replaced Before the End of Their Expected Useful Life During the Course of One Year, Reported Annually, With an Explanation for the Replacement		
Metric	Number	Percentage
Advanced meters replaced	29,568	0.55%
Explanation for the replacements: These advanced electric meters were replaced due to a malfunction before the end of their expected useful life (e.g., damaged meter, etc.).		
Note: Percentage is defined as the number of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, divided by the number of advanced meters installed, with that resulting number multiplied by 100.		

Metric 8: Number and percentage of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests, and the number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.

Number and Percentage of Advanced Meters Field Tested at the Request of Customers Pursuant to Utility Tariffs Providing for Such Field Tests, and the Number of Advance Meters Tested Measuring Usage Outside the Commission-Mandated Accuracy Bands		
Metric	Number	Percentage
Advanced meters field tested at the request of customers[a]	3,810	0.07%
Advanced meters tested measuring usage outside the Commission-mandated accuracy bands[b]	20	0.52%
(a) Percentage is defined as the number of advanced meters field tested divided by the number of advanced meters installed, with that resulting number multiplied by 100.		
(b) Percentage is defined as the number of advanced meters field tested found outside of the Commission-mandated accuracy bands divided by the number of advanced meters tested at the request of the customer between 7/1/16 and 6/30/17 with that resulting number multiplied by 100.		

Metric 9: Number and percentage of customers using a utility web-based portal to access energy usage information or to enroll in utility energy information programs or who have authorized the Utility to provide a third-party with energy usage data.

Number and Percentage of Customers Using a PG&E Web-based Portal to Access Energy Usage Information or to Enroll in PG&E Energy Information Programs or Who Have Authorized PG&E to Provide a Third-Party with Energy Usage Data		
Metric	Number	Percentage
Customers using a PG&E web-based portal to access energy usage information[a]	1,624,056	30%
Customers using a PG&E web-based portal to enroll in PG&E energy information programs	140,138	2.6%
Customers who have authorized PG&E to provide a third-party with energy usage data	145,029	2.7%
(a) This number represents the unique number of customers who have clicked on the "My Usage" tab within My Energy at least one time during the reporting period (July 1, 2016 through June 30, 2017).		

3.2. Plug-In Electric Vehicle (PEV) Metric

Metric 1: Number of customers enrolled in time-variant EVs tariffs.

Number of PG&E Customers Enrolled in a Time-Variant Electric Vehicle Tariffs	
Metric	Value
Number of EV-A Customers	36,761 customers
Number of EV-B Customers	575 customers
Note: Utilities currently have limited ability to determine which customers have EVs. As methods for acquiring this information were determined in that proceeding, this metric should be updated. Metrics related to metering arrangements should be deferred until after PEV metering policy is set in Alternative Fueled Vehicles OIR (Rulemaking 09-08-009).	

3.3. Energy Storage Metric

Metric 1: MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals as of June 30, 2017.

MW and MWh of PG&E-Owned or Operated Energy Storage Interconnected at the Distribution System Level		
Metric		Value
Sodium Sulfur Batteries	Vaca Dixon	2MW/14MWh
	Yerba Buena	4MW/28MWh
Lithium Ion Batteries	Brown Valley	0.5MW/2MWh
Note: As highlighted in this Smart Grid Project Update, a 2 MW/14 MWh battery storage system was commissioned at a PG&E substation near Vacaville in August 2012 and a 4 MW/28 MWh battery storage system on a distribution circuit in San Jose California in May 2013.		

3.4. Grid Operations Metrics

Metric 1: The systemwide total number of minutes per year of sustained outage per customer served as reflected by the SAIDI Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 22 major events in the latest time period of July 1, 2016 through June 30, 2017.

PG&E's System Average Interruption Duration Index, Major Events Included and Excluded		
Period	Metric	Value
2016-2017	SAIDI – Major Events Included	253.3
2016-2017	SAIDI – Major Events Excluded	94.3
2015-2016	SAIDI – Major Events Included	137.3
2015-2016	SAIDI – Major Events Excluded	110.6
2014-2015	SAIDI – Major Events Included	177.5
2014-2015	SAIDI – Major Events Excluded	102
2013-2014	SAIDI – Major Events Included	126.2
2013-2014	SAIDI – Major Events Excluded	112.7
2012-2013	SAIDI – Major Events Included	139.4
2012-2013	SAIDI – Major Events Excluded	139.4
2011-2012	SAIDI – Major Events Included	141.1
2011-2012	SAIDI – Major Events Excluded	141.1

Metric 2: How often the systemwide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 22 major events in the latest time period of July 1, 2016 through June 30, 2017.

PG&E's System Average Interruption Frequency Index Major Events Included and Excluded		
Period	Metric	Value
2016-2017	SAIFI – Major Events Included	1.388
2016-2017	SAIFI – Major Events Excluded	0.883
2015-2016	SAIFI – Major Events Included	1.139
2015-2016	SAIFI – Major Events Excluded	1.008
2014-2015	SAIFI – Major Events Included	1.164
2014-2015	SAIFI – Major Events Excluded	0.889
2013-2014	SAIFI – Major Events Included	1.093
2013-2014	SAIFI – Major Events Excluded	1.040
2012-2013	SAIFI – Major Events Included	1.108
2012-2013	SAIFI – Major Events Excluded	1.108
2011-2012	SAIFI – Major Events Included	1.067
2011-2012	SAIFI – Major Events Excluded	1.067

Metric 3: The number of momentary outages per customer systemwide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 22 major events in the latest time period of July 1, 2016 through June 30, 2017.

PG&E's Momentary Average Interruption Frequency Index Major Events Included/ Major Events Excluded		
Period	Metric	Value
2016-2017	MAIFI – Major Events Included	2.144
2016-2017	MAIFI – Major Events Excluded	1.448
2015-2016	MAIFI – Major Events Included	1.806
2015-2016	MAIFI – Major Events Excluded	1.638
2014-2015	MAIFI – Major Events Included	1.710
2014-2015	MAIFI – Major Events Excluded	1.404
2013-2014	MAIFI – Major Events Included	1.517
2013-2014	MAIFI – Major Events Excluded	1.455
2012-2013	MAIFI – Major Events Included	1.826
2012-2013	MAIFI – Major Events Excluded	1.826
2011-2012	MAIFI – Major Events Included	1.643
2011-2012	MAIFI – Major Events Excluded	1.643

Metric 4: Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available.

Number and Percentage of PG&E's Customers Per Year and Circuits Per Year Experiencing Greater Than 12 Sustained Outages Per Year			
Period	Metric	Number	Percentage
2016-2017	Customers Experiencing Greater Than 12 Sustained Outages Per Year	3,826	0.070%
2016-2017	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	1,266	39.28%
2015-2016	Customers Experiencing Greater Than 12 Sustained Outages Per Year	1640	0.030%
2015-2016	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	10	0.333%
2014-2015	Customers Experiencing Greater Than 12 Sustained Outages Per Year	799	0.0148%
2014-2015	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	10	0.333%
2013-2014	Customers Experiencing Greater Than 12 Sustained Outages Per Year	410	0.007%
2013-2014	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	5	0.16%
2012-2013	Customers Experiencing Greater Than 12 Sustained Outages Per Year	893	0.02%
2012-2013	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	14	0.46%
2011-2012	Customers Experiencing Greater Than 12 Sustained Outages Per Year	965	0.02%
2011-2012	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	19	0.6%
Note: (Percentage of customers experiencing greater than 12 sustained outages per year equals [(the number of customers experiencing greater than 12 sustained outages in a year) divided by (the total number of customers)] with the resulting number multiplied by 100. Percentage of circuits experiencing greater than 12 sustained outages per year equals [(the number of circuits experiencing greater than 12 sustained outages in a year) divided by (the total number of circuits)] with the resulting number multiplied by 100.			

Metric 5: System load factor and load factor by customer class for each year starting on January 1, 2016 through December 31, 2016. Data is unavailable for any other time frame.

PG&E's Load Factors	
Metric	Value
System Load Factor	56.18%
Residential Load Factor	38.33%
Non-Residential < 200 kW Load Factor	Small L&P: 51.78% Medium L&P: 48.46%
Non-Residential ≥ 200 kW Load Factor	Large L&P: 67.07%
Other (Agriculture) Load Factor	50.55%
Note: Until advanced meters are fully deployed for residential, small C&I, and small agriculture customers, load factors will be calculated using estimates, rather than measured directly.	

Metric 6: Number of and total nameplate capacity of customer-owned or operated, grid-connected DG facilities. The data are cumulative through June 30, 2017.

Number and Total Nameplate Capacity of PG&E's Customer-Owned or Operated Grid Connected Distributed Generation Facilities		
Metric	Number of Facilities	Capacity (MW)
CSI Distributed Generation Facilities	63,133	812
SGIP Distributed Generation Facilities	1,202	303
Non-CSI and Non-SGIP Distributed Generation Facilities	249,132	2,523
Totals	313,467	3,637
Note: Information and estimates about production of DG facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast. D.12-04-025 defines Distributed Generation as "Customer-owned or operated generating systems that are enrolled with a utility in the Self Generation Incentive Program (SGIP) or the California Solar Initiative (CSI) or otherwise operating under a Feed In Tariff (FIT)." Significant customer-side DG capacity has been interconnected outside of the CSI and SGIP programs. Therefore, data includes all NEM and non-export Rule 21 interconnected facilities. For Rule 21 facilities, capacity for solar generating facilities is reported as the PV CEC-AC rating, while for non-solar facilities, capacity is reported as the maximum inverter capacity. Please note that in last year's annual report, PV capacity was reported as the maximum inverter capacity of the system.		

The CSI is the solar rebate Program for California consumers that are customers of the IOUs such as Pacific Gas and Electric Company (PG&E). This program funds solar on existing homes, existing or new commercial installations, agricultural sites as well as government and non-profit buildings.

CSI also funds a rebate program, administered by Grid Alternatives, for low-income residents that own their own single-family home and meet a variety of income and housing eligibility criteria. This program is called the Single-family Affordable Solar Homes Program.

Additionally PG&E administers a CSI-funded solar rebate Program for multifamily affordable housing. This program is called the Multifamily Affordable Solar Housing Program.

The SGIP provides incentives for storage and generation technologies installed behind the meter to offset all or a portion of on-site load. SGIP's goals include grid support, GHG reduction and market transformation.

Metric 7: Total electricity deliveries from customer-owned or operated, grid-connected DG facilities, reported by month and by ISO sub-Load Aggregation Point. This information is for July 1, 2016 through June 30, 2017.

Year	Month	Approximate Exports (GWh)
2016	Jul	226.66
2016	Aug	204.51
2016	Sept	185.32
2016	Oct	144.94
2016	Nov	119.97
2016	Dec	105.11
2017	Jan	101.88
2017	Feb	127.04
2017	Mar	234.89
2017	Apr	266.02
2017	May	319.05
2017	Jun	296.23
Note: Information and estimates about production of DG facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast.		

<u>Metric 8</u>: Number and percentage of distribution circuits equipped with automation or remote control equipment, including SCADA systems. The measure is for July 1, 2016 through June 30, 2017.

Number and Percentage of PG&E's Distribution Circuits Equipped With Automation or Remote Control Equipment, Including SCADA			
Metric	# of Automated Circuits	Total Circuits	Percentage
PG&E Distribution Circuits Equipped With SCADA at the Breaker	2,830	3,277	86.4%
<u>Note</u>: Percentage of distribution circuits equipped with automation or remote control equipment equals the number of distribution circuits equipped with automation or remote control equipment) divided by the total number of distribution circuits with the resulting number multiplied by 100.			

CHAPTER 4

CONCLUSION

4. Conclusion

As growth in DERs continues, PG&E continues to build the capabilities for a platform to enable a new energy landscape - one filled with customer choice and cleaner, renewable, and distributed energy.

The remainder of 2017 will be an exciting year as PG&E continues efforts around the EPIC Program. EPIC delivers value to customers through the opportunity for PG&E to cost-effectively develop and demonstrate innovative technologies which can advance PG&E's core values of Safety, Reliability, and Affordability. Through these projects, the EPIC Program also contributes learnings that support important California clean energy policy goals, including GHG reduction goals and renewable energy targets.

PG&E will continue to advance its DRP in order to better integrate the growing number of DERs onto the distribution system. PG&E is aligning with the CA IOUs on standardization of various aspects of Smart Inverters with the intention of pursuing additional pilots to test and enhance these capabilities.

With the investments made, Customers continue to receive benefits. For the period, customers enjoyed an estimated $204.6 million in benefits, inclusive of several key programs.

Lastly, PG&E continues to maintain a strong commitment to supplier diversity and its aspiration to exceed the Commission's supplier diversity goals set forth in General Order 156.

CHAPTER 5

APPENDIX

5. Appendix

2017 Annual Smart Grid Report
Approximate Recorded Smart Grid Project Costs From July 1, 2016 Through June 30, 2017[9]

Project Name	7/1/2016 to 6/30/2017 Approximate Recorded Amount ($ millions)
Customer Engagement and Empowerment Projects	
Supply Side (SSP) / Supply Side II (SSP II) DR Pilot (Continuation of IRM Pilot Phase 2)	$0.59 Million
Demand Response Transmission and Distribution System Integration	$0.6 Million
AC Cycling Next Generation Technology Assessment	$6.3 Million
Demand Response Plug-In Electric Vehicle (DR PEV) Pilot	$1.6 Million
Electric Vehicle Rates	$0.1 Million
Electric Vehicle Infrastructure	$1.0 Million
Energy Diagnostics and Management	$6.3 Million
Energy Alerts	$0.024 Million
Share My Data (Customer Data Access) Project	$1.85 Million
Energy Data Access	$0.3 Million
Stream My Data aka Home and Business Area Network (HAN)	$0.4 Million
Building Benchmarking Portal	$2.9 Million
Time Varying Pricing (TVP) Rates	$7.2 Million
Automated Demand Response (AutoDR) Program	$3.6 Million
Smart Thermostat Study	$1.3 Million
Distribution Automation and Reliability Projects	
Distribution Substation Supervisory Control and Data Acquisition (SCADA) Program	$51.6 Million
Battery Energy Storage System (BESS) Demonstration Projects	Refer to EPIC box
Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)	$8.9 Million
Install Smart Grid Line Sensors Pilot	$1.4 Million
Voltage and Reactive Power (Volt/Var) Optimization System Pilot	$3.5 Million
Detect and Locate Faulted Circuit Conditions Pilot	$2.6 Million
Transmission Automation and Reliability Projects	
Compressed Air Energy Storage (CAES) Demonstration Project	$0.2 Million
Transmission Substation SCADA Program	$27.4 Million
Modular Protection Automation and Control (MPAC) Installation Program	$55.0 Million
Synchrophasor Project Realization	$1.8 Million
Asset Management and Operational Efficiency Projects	

[9] For information on project costs in former years, please reference past Smart Grid Deployment Plan Updates on CPUC's California Smart Grid website at: http://www.cpuc.ca.gov/General.aspx?id=4693.

Project Name	7/1/2016 to 6/30/2017 Approximate Recorded Amount ($ millions)
Network Supervisory Control and Data Acquisition (SCADA) Monitoring Project	$7.7 Million
Smart Grid Short-Term Demand Forecasting Pilot Project	$1.0 Million
Security (Physical and Cyber) Projects	
Identity and Access Management Project	$11.54 Million
Integrated and Cross-cutting Systems Projects	
Telecommunications Architecture	$5.7 Million
California Energy Systems for the 21st Century Program	$4.0 Million
Electric Program Investment Charge Program	$21.4 Million

Project Name	Completion Date
Customer Engagement and Empowerment Projects	
Intermittent Renewable Resource Management (IRRM) Pilot Phase 1 In the IRRM Pilot Phase 1, PG&E leveraged work performed under the C&I DR Participating Load Pilot to provide regulation services to the CAISO. The objective of the IRRM Pilot Phase 1 was to demonstrate whether customers can provide second by second frequency-regulation service needs to the CAISO.	2011
Plug-In Hybrid Electric Vehicle/Electric Vehicle (PHEV/EV) Smart Charging Pilot In the PHEV/EV Smart Charging Pilot, PG&E and the Electric Power Research Institute tested baseline functionalities of PEV charging hardware by conducting an end-to-end system connectivity to evaluate potential residential smart charging capabilities utilizing the load management software over the SmartMeter™ network.	December 2011
My Energy Web Tools PG&E's customer website – My Energy – allows residential, SMB, and small agricultural customers to view usage, price and cost, and take advantage of various rate analysis tools. The usage information is displayed in a variety of formats including year-to-year comparison, peak/off-peak, hourly and 15-minute interval data (depending on the granularity of the SmartMeter™ data), bill to date and monthly bill forecast. The "My Energy" website will also include a rate calculator which will calculate the customer bill under a variety of available rate plans.	November 2012
The Green Button Initiative In PG&E's Green Button Initiative, the Green Button tool provides customers with a means of easily accessing and downloading their energy use online in a standardized format that can be shared with energy service providers.	October 2012
Proxy Demand Resources (PDR) Program Phase 1 As part of the Commission's vision of integrating retail-wholesale DR programs, in the PDR Program Phase 1, PG&E is in the process of enabling its retail DR programs to directly participate in the CAISO's wholesale market – PDR product. Phase 1 of this project was focused on assembling the proper tools (i.e., telemetry, forecasting) and integrating interfaces (procurement back-end systems to schedule, notify and settle) that PG&E needs to operate when bidding available DR resources in the CAISO market.	2013
Energy and Carbon Management System (ECMS) In the ECMS, PG&E has developed tools specifically for PG&E's large C&I customer account representatives to identify opportunity customers and enable a consultative energy discussion with those customers using advanced usage analytics and financial metrics for proposed EE projects.	December 2013
SmartMeter™ Program PG&E's SmartMeter™ Program launched the deployment of foundational technology to help PG&E's customers understand how and when they use energy, including through automated home energy management. The SmartMeter™ system improved infrastructure integrity, helped PG&E manage energy demand, and also enabled PG&E to provide more reliable service. Through these broad systemwide enhancements, the SmartMeter™ Program has served the vital foundational step to enable creation of the Smart Grid, which in turn fosters a clean energy economy and sustainable economic expansion.	December 2013
Green Button Connect (GBC) Beta GBC is a software interface that allows PG&E customers to easily share their SmartMeter™ enabled energy usage data with other energy service providers. These developers can then "mash up" the data in unique ways to provide valuable insights to customers. GBC was retired when PG&E launched its Share My Data platform.	March 2015

Project Name	Completion Date
Universal Audit Tools (UAT) PG&E provides the Home Energy Checkup and Business Energy Checkup (also known as Universal Audit Tools) for residential and SMB customers through My Energy. These tools utilize SmartMeter™ data along with other customer insights to make it easy for our customers to find energy savings ideas that are particular to how they use energy. The tools are progressive in nature, continually learning based on the information the customer provides, and include recommendations across EE, DR, DG, and behavioral changes.	September 2012
HAN Enablement Program – Phase 1 & Phase 2 PG&E's HAN Enablement Program is an infrastructure that allows customers to register and commission a standards compliant device with PG&E's AMI network to receive near RT data from their SmartMeter™. In HAN Phase 1 (Initial Deployment), which ran from March 1, 2012 through April 30, 2013, PG&E installed and supported 430 in-home displays with residential customers. Starting in January 2013, PG&E launched HAN as a platform, making the capability to register a device and received near real time usage information from a customer's electric SmartMeter™ available to all eligible customers across its service territory.	April 2013 and February 2014
Opower/Honeywell Smart Thermostat Assessment Pilot PG&E conducted a Smart Thermostat field assessment with Opower and Honeywell to evaluate the energy benefits that accrue to customers who utilize internet-enabled thermostats, when exposed to behavioral energy saving messaging. This effort was a component of the EE Portfolio's Emerging Technologies Program. PG&E successfully installed Honeywell Smart Thermostats in 505 residential homes in the San Francisco Bay Area and the Central Valley in February 2013. Opower and PG&E monitored usage differences between the test and control groups for a 12-month period.	July 2014
Distribution Automation and Reliability Projects	
Cornerstone Improvement Project – Feeder Automation The Cornerstone Improvement Project includes the installation of distribution feeder fault locating, isolation and service restoration (FLISR) systems on select urban and suburban circuits. The project is expected to result in reliability improvements for PG&E customers. The Feeder Automation component of Cornerstone Improvement Project involves implementing feeder automation on approximately 400 distribution circuits. The project scope includes automating mainline protection equipment utilizing FLISR schemes to restore unaffected customers within five minutes.	December 2013
Distribution Management System (DMS) Project The DMS Project implements electronic wall maps to assist in distribution operations control center consolidation. This project is a key strategic system implementation for the electric distribution system to provide increased grid visibility and control capability. PG&E commenced implementation activities in February 2012 and concluded its development effort in November 2014. The deployment of the technology occurred in parallel with the Distribution Control Center consolidation project beginning in November 2014 which completed in November 2016. Minor enhancements were also implemented to improve network grid visibility.	November 2014

2017 Annual Smart Grid Report
Closed Smart Grid Projects
(Continued)

Project Name	Completion Date
SmartMeter™ Outage Management Integration Project The SmartMeter™ Outage Management Integration project integrates the SmartMeter™ "Last Gasp" and Restoration messages into PG&E's Outage Management System for outage notification to operators and dispatchers and improved outage restoration. Phase I project delivered: (1) the capability to create trouble reports from AMI alarms when an associated customer call has been received; (2) the capability to ping a transformer to determine if an outage is larger than it was inferred to be; and (3) the capability to ping individual meters to determine whether they have been restored. Phase 2 of the project delivered functionality to identify and isolate downstream outages that have occurred prior to a larger upstream outage. Additionally, it will enhance the capability introduced in Phase 1 by removing the requirement for an associated customer call and automatically creating trouble reports using AMI only reports.	November 2015
Transmission Automation and Reliability Projects	
Regional Synchrophasor Investment Project As part of this project, PG&E installed or upgraded Synchrophasor technology, also known as Phasor Measurement Units (PMU), throughout its service territory, has networked them together, and provided the data in a secured interface to PG&E's electric transmission operators, WECC, neighboring utilities, and the CAISO. The data exchange portion of the project includes positioning PG&E to share data with WECC. Nine other partner entities can coordinate and exchange data amongst partner entities, including PG&E.	May 2014
Asset Management and Operational Efficiency Projects	
Transformer Load Management Project The SmartMeter™ Transformer Loading Management project enables T&D electric planning engineers and estimators to access actual customer usage data from SmartMeter™ for analysis in equipment sizing and voltage analysis. The solution will enable PG&E to report transformer (or multiple transformers) load based on interval usage data and the ability to drill down to month, week, day, and Service Point level to see the peak usage. The solution will also identify transformer (or multiple transformers) by load category (over loaded, under loaded) over the entire SmartMeter™ population.	June 2012
Electric Distribution Geographic Information System and Asset Management (ED GIS/AM) Project The ED GIS/AM project is a continuation of and enhanced approach to the Automated Mapping and Facilities Management (AM/FM) Project, where PG&E upgraded hardware and software components from 2008 2010 and completed alignment of electric and gas maps to a common coordinate scheme or "land base," to prepare the maps for migration and conversion into a new enterprise GIS solution. While the purpose and scope of the ED GIS/AM project is consistent with and leverages work completed as part of the predecessor AM/FM project, key enhancements are being made to drive increased business value with the integrated GIS and enterprise asset management system (SAP) data. A significantly more rigorous approach to assure data quality and implement data governance processes is included as part of the new ED GIS/AM project. In addition, the scope of the ED GIS/AM project has been expanded to include web based analytics for multiple ED functions. These and other capabilities are more fully detailed and scoped in the GIS/AM project as compared to the 2011 GRC AM/FM forecast, resulting in a more comprehensive and longer duration project.	December 2015

2017 Annual Smart Grid Report
Closed Smart Grid Projects
(Continued)

Project Name	Completion Date
Condition-Based Maintenance (CBM) – Substation Project The CBM Substation Project was a PG&E initiative to convert substation inspections collected on paper to a centralized electronic form. Centralizing the data aids in identifying problematic substation assets based on inspected condition trends in a predictive manner. The CBM technology solution for substation provides the platform for equipment inspection readings, temperature, and other data points to provide equipment predictive maintenance. The solution will automate many of the manual processes that are used today including: (1) review of station inspection and test data to identify abnormal conditions; (2) update maintenance trigger plans from oil condition assessment results, counter readings, etc.; and (3) equipment ranking for replacement decisions. The tool is also designed to provide easy access to inspection and test data to asset strategy and engineering personnel that do not have it readily available today. The data will be used to adjust maintenance triggers and for capital investment strategy.	February 2013
Load Forecasting Automation Program The Load Forecasting Automation Program will automate existing manual electric distribution system load forecasting to increase accuracy of the process and improve forecast documentation. Current and future SCADA data will be gathered and stored within the existing data historian system and will become an input to the new forecasting tool. Circuits with SCADA will provide hourly load data into the historian system and non-SCADA circuits will provide a single monthly peak load from monthly substation inspections. Additionally, this project will replace analog bank demand meters with electronic recording meters.	October 2012
Security (Physical and Cyber) Projects	
Advanced Detection and Analysis of Persistent Threats (ADAPT) Cyber Security Project The ADAPT project is focused on increasing PG&E's ability to effectively anticipate, prevent, and respond to current and shifting cyber and physical threats by enhancing the following three control areas: a) Intelligence and threat management controls: Build specific "early-warning" controls that electronically collect, analyze, and correlate information on Utility targeting threats before they "approach" the Utility's logical perimeter. b) Advanced detective and preventative controls: Develop controls that "harden" the Utility's cyber security infrastructure with multiple layers of technology to filter, quarantine, and send alarms on questionable data. c) Adaptive response controls: Enhance incident monitoring, response, and investigation capabilities to quickly respond to potential security incidents.	May 2012
Integrated and Cross-Cutting Systems Projects	
Applied Technology Services (ATS) Distribution Test Yard (DTY) The DTY will serve as an electrical laboratory that includes simulated distribution capabilities for monitoring and evaluating various new distribution tools, equipment, and applications. It will include the necessary primary line equipment with isolated communications networks to allow safe and thorough testing without risking network security issues. This DTY is part of the overall ATS end to end test capability for distribution systems of the future.	September 2012
SmartMeter™ Operations Center (SMOC) The SMOC project implements telecommunication network operations management capabilities to support PG&E's SmartMeter™ network to handle growth in the number of deployed meters, effectively monitor the increased amount of data communications from the meters, bring new SmartMeter™-related customer services on-line efficiently, and enable timely customer response as well as proactive reliability and availability management. This scope includes designing and implementing a new SMOC for the day to day operations of the existing installed systems and ensure vendor production and operational commitments.	July 2012

Project Name	Completion Date
Data Historian Foundation Project This project will implement enhanced data historian software for managing and analyzing operational data with select user groups in electric transmission, gas operations, power generation, and energy procurement. When deployed and integrated with other electric systems such as EMS and SCADA, the new data historian will serve as the central data archiving and analysis system for all-time series operational data. This solution enables PG&E operators, engineers, managers and executives to analyze, visualize, and share operational and business data in a manner that not only makes the most sense to them, but also informs intelligent decision-making throughout the utility value chain. The benefits of this capability include productivity improvements, situational awareness, reliability improvements, and regulatory compliance. A separate project is required to enable these capabilities for electric distribution.	July 2014
Information Management Architecture PG&E proposed to invest in a core set of Information Management and processing capabilities to allow participants in the Smart Grid to have timely access to the best available data to drive their energy related decisions. The Information Architecture foundation includes enhanced decision support tools to more accurately analyze, predict, and respond to energy impacting events based on data processed from a multitude of systems and stakeholders. The approach to information management is being optimized and will launch as a new project in 2017.	January 2016