Energy Division Compliance Report Filing Cover Sheet

A. Document Name

1. Utility Name: PG&E
2. Document Submission Frequency (Annual, Semi-Annual, YTD, Quarterly, Monthly, Weekly, Ad-Hoc, Once, Other Event): Annual
3. Report Name:

   Smart Grid Technologies

4. Reporting Interval (for this submission, e.g., 2015 Q1): Calendar year 2018
5. Document File Name (format as 1 + 2 + 3 + 4):

   PGE Annual Smart Grid Technologies 2018 Report

6. Append the confidential and/or cover sheet notation, as appropriate.

N/A

Sample Document Names

Utility Name + Submittal Frequency + Report Name + Year + Reporting Interval + (COV or CONF or both or neither)

SCE Annual Procurement Report 2014	*PGE Monthly Gas Report 201602* CONF
SDGE Quarterly DR Forecast 2015Q1	*PGE Daily Gas Report 201602*30 COV
PGE Monthly Gas Report 201602	*PGE Monthly Gas Report 201602* COV CONF

7. Identify whether this filing is: ◉ original or ○ revision to a previous filing.
   a. If revision, identify date of the original filing:

B. Documents Related to a Proceeding

All submittals should reference both a proceeding and a decision, if applicable. If not applicable, leave blank and fill out Section C.

1. Proceeding Number (starts with R, I, C, A, or P plus 7 numbers):
   R. 08-12-009
2. Decision Number (starts with D. plus 7 numbers): D.10-06-047 and D.14-12-004
3. Ordering Paragraph (OP) Number from the Decision:

C. Documents Submitted as Requested by Other Requirements

If the document submitted is in compliance with something other than a proceeding, (e.g., Resolution, Ruling, Staff Letter, Public Utilities Code, or sender's own motion), please explain:

N/A

Energy Division Compliance Report Filing Cover Sheet

D. Document Summary

Provide a Document Summary that explains why this report is being filed with the Energy Division (ED). This information is often contained in the cover letter, introduction, or executive summary.

Commission Resolution G-3429, dated December 15, 2011, authorized Pacific Gas and Electric Company (PG&E_ to execute a Servicing Agreement between PG&E and the ClimateSmart[TM] Charity, and directed PG&E to submit an unredacted annual report through an Information-only filing. This report is due on March 15th, annually and will be filed annually until all of the procured GHG emission reduction requirements have been delivered, including those procured by PG&E to meet the performance guarantee, as specified in Decision 06-12-032.

In compliance with Ordering Paragraph 14, PG&E hereby submits the attached PDF file of PG&E's 2016 ClimateSmart Annual Report.

E. Sender Contact Information

1. Sender Name: Zandre Dumas
2. Sender Organization: PG&E
3. Sender Phone: 415-973-8205
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F. Confidentiality

Is this document confidential? (•) No ( ) Yes

If **Yes**, provide an explanation of why confidentiality is claimed and identify the expiration of the confidentiality designation (e.g., Confidential until December 31, 2020.)

G. CPUC Routing

Energy Division's Director, Ed Randolph, requests that you not copy him on filings sent to ED Central Files. Identify below any Commission staff that were copied on the submittal of this document. Names of Commission staff that sender copied on the submittal of this Document:

PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID ANNUAL REPORT – 2018

SMART GRID TECHNOLOGIES

ORDER INSTITUTING RULEMAKING 08-12-009

CALIFORNIA PUBLIC UTILITIES COMMISSION

Contents

CHAPTER 1

SMART GRID ANNUAL REPORT

EXECUTIVE SUMMARY

1. Smart Grid Annual Report Executive Summary

Throughout the reporting period of July 2017 to June 2018, Pacific Gas and Electric Company (PG&E or the Company or the Utility) continued to build capabilities to deliver on its vision of modernizing its grid. This vision integrates new energy devices and technologies with the grid and allows their owners to realize greater value from their energy technology investments—Energy Efficiency (EE), rooftop solar, electric vehicles (EV), energy storage, Demand Response (DR) technologies, etc.—by virtue of their grid connectivity. PG&E plays a critical role in delivering this interconnected and Integrated Grid Platform (IGP) that will define tomorrow's energy landscape for California. The innovative programs and plans detailed throughout this report help PG&E achieve the vision while also maintaining a safe and reliable grid.

Distributed Energy Resource (DER) growth continues in PG&E's service territory. A snapshot of potential projections and goals for PG&E territory include:

- ~245,000 EVs growing to over 300,000 by 2020.[1] Governor Brown has set a target of 5 million zero-emission vehicles in California by 2030, of which PG&E would represent about 40%, or 2 million vehicles.
- ~312,000 solar rooftop photovoltaic (PV) systems growing to over 640,000 by 2020.[2]
- Continued growth in battery storage, including 580 mandated megawatts (MW) contracted by 2020. PG&E's vision is to lead in storage and includes planning to compete-to-own 1,000 MW energy storage by 2030.

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 emerging grid technologies can help PG&E to manage the additional complexity that DERs introduce to

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1 2020 EV forecast reflects California Energy Commission (CEC) estimates

2 2020 solar rooftop PV forecast reflects CEC estimates.

operating the grid, while also increasing the amount of information available for grid operations, allowing utilities better oversight and eventual control of DERs.

PG&E's Grid Modernization Vision

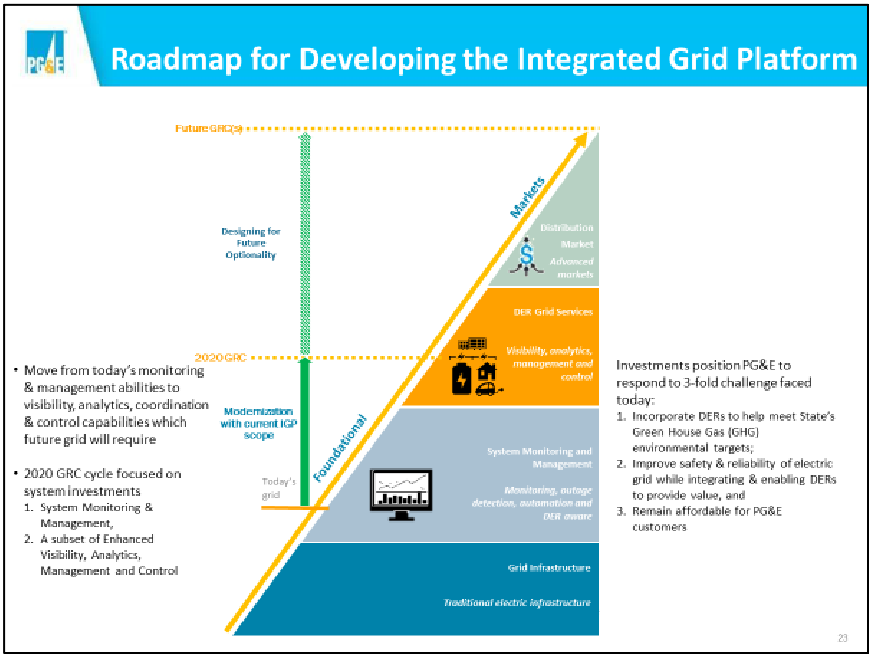
The electric grid of the future enables continued gains for clean-energy technologies and California's economy, in a way that gives our customers maximum flexibility, maximum choice in how they use energy, and ultimately maximum value. PG&E's smart grid investments help further the grid modernization vision and drives towards the development of an IGP that improves situational awareness, operational efficiency and enhances cybersecurity to meet today's challenges while positioning to meet the demands of a dynamic energy future. This is enabled through investments in Safety, Resiliency, Security, Customer Service, and DER integration and enablement – furthering reliability and operational efficiency.

Grid Modernization Supporting DER Enablement

PG&E is developing its Grid Modernization Plan (GMP) to support DER enablement and associated smart grid investments, as mandated by the California Public Utilities Commission (CPUC or Commission) in their Distribution Resources Plan (DRP) Decision related to Grid Modernization. PG&E held a one-day workshop on June 25, 2018 to provide stakeholders an opportunity to provide initial input on PG&E's GMP (related to DER enablement) prior to PG&E's GRC filing. Specifically, the CPUC required PG&E (and other California Investor-Owned Utilities (IOU) to file a GMP as part of their triennial General Rate Case (GRC) filing. The GMP will include:

- 10-year vision for investments needed to support DER growth
- High level status of grid modernization upgrades initiated and completed to date
- Additional spending requirements necessary to complete the grid modernization objectives, within and beyond the current GRC cycle
- A high level but complete status of DER related Research, Development and Demonstration (RD&D) projects planned, in process, proposed and/or approved
- The IOUs will need to address issues raised in the workshop in their GMP GRC submissions

At the June 25 workshop, PG&E presented its 10-year vision for modernizing its electric distribution grid. PG&E's grid modernization vision is to develop an **IGP** that improves situational awareness, operational efficiency & enhances cybersecurity to meet today's



challenges while positioning to prepare for the new challenges associated with climate change, State policy goals and meet demands of a dynamic energy future.

Figure: PG&E's Roadmap for Developing the Integrated Grid Platform

PG&E's IGP is a foundational program that builds on PG&E's past investments and leverages previous R&D efforts, which focus on developing:

1. Seamless integration of mission critical applications required to increase efficiency and operational intelligence capabilities of today's Distribution Operator

2. Increased operational flexibility and control to prepare for and manage more dynamic and extreme weather events

3. Improved communication and cybersecurity infrastructure required to operate in today's environment

4. Enables flexibility for future functionality and 3rd party integration as DER capabilities, customer preferences, policy drivers and grid needs evolve

PG&E's grid modernization vision, enabled by smart grid investments, are largely informed by the work done through the **Electric Program Investment Charge (EPIC)**. Through EPIC PG&E has been able to cost-effectively develop and demonstrate innovative technologies which can advance PG&E's smart grid developments, including many of the technologies critical to our future IGP. EPIC demonstrations aid in identifying key requirements, implementation challenges, and benefit-cost details to inform future deployment. EPIC projects also support the creation of new and valuable Intellectual Property (IP), which can lead to improved products and services that help improve the operations of the electricity grid by reducing operating expenses and/or potentially generating alternative forms of incremental revenue that can reduce customer costs.

Technology innovation programs like EPIC are critical to continued advancement of the grid, both to enable increased customer choice and further California's clean energy objectives as well as to increase safety and resiliency in light of climate change. Never has there been a time where innovation plays a more critical role to the future of our grid, and we need to act quickly to meet these opportunities head on. PG&E is excited to embark on new technology demonstrations contained within that plan which can help build on past projects, meet emerging grid needs and California policy objectives, and ensure that the customers and the state can leverage the maximum benefit of this program.

Executive Summary Conclusion

PG&E's vision for modernizing its grid through smart grid investments furthers developments towards a secure, resilient, reliable and affordable platform that enables continued gains for clean-energy technologies and California's economy, in a way that gives our customers maximum flexibility, maximum choice in how they use energy, and ultimately maximum value. The energy landscape in PG&E service territory is evolving in complexity—a result of increased DER penetration and weather induced events, including a changing climate. Smart grid technologies are critical to help meet the climate-induced challenges of increasing wildfires and extreme weather events through increased visibility and grid flexibility. PG&E progressed these capabilities over the reporting period through the EPIC Program, DRP activities, Smart Inverters (SI) Standards/Certification advancements, customer programs, and other projects across Distribution, Transmission, Security, and Information Technology (IT).

CHAPTER 2

SELECT SMART GRID TECHNOLOGIES FURTHERING GRID MODERNIZATION OBJECTIVES

2. Select Examples Furthering PG&E's Grid Modernization Vision

Safety & Resiliency

To help meet the climate-driven challenge of increasing wildfires and extreme weather events, PG&E announced a comprehensive Community Wildfire Safety Program over the reporting period. PG&E is working in close coordination with first responders, civic and community leaders and customers on this program. These efforts will have an immediate impact on reducing wildfire threats and improving safety, in advance of the start of wildfire season in Northern and Central California. Years of drought, extreme heat and 129 million dead trees have created a "new normal" for California. In the interest of public safety, and following the wildfires in 2017, PG&E is implementing additional precautionary measures intended to reduce the risk of wildfires. PG&E is continuously evolving its operating practices in response to new standards and regulations—but this new normal means even more must be done in partnership to strengthen the safety and resilience of the state's energy infrastructure.

The multi-faceted program focuses on three key areas:

1. Bolstering wildfire prevention and emergency response efforts;
2. Working with customers and first responders to put in place new and enhanced safety measures; and
3. Doing more over the long term to harden the electric system to help reduce wildfire threats and to keep customers safe, PG&E will leverage new technologies in support of this effort.

PG&E will leverage various technologies and a new control center as part of this effort. Technology driven innovations include but are not limited to:

- Establishing a Wildfire Safety Operations Center to monitor wildfire risks in real-time and coordinate prevention and response efforts with first responders.
- Expanding the company's weather forecasting and modeling by installing a network of PG&E-owned and operated weather stations across the service area.

- Refining and executing protocols for proactively turning off electric power lines in areas where extreme fire conditions are occurring, and implementing the appropriate communications and resources to help inform, prepare and support our customers and communities.
- Expanding our practice of disabling line reclosers and circuit breakers in high fire-risk areas during fire season.
- Partnering with communities to develop and integrate microgrids to help support community facility resilience in the event of major natural disasters.

PG&E's EPIC 3 portfolio also contains key enablers for adapting our grid to the changing climate. The following are select technologies furthering PG&E's grid resiliency as proposed in the EPIC 3 demonstration portfolio:

- EPIC 3.15: Proactive Wire Down – Utilize Rapid Earth Fault Current Limiter technology that automatically detects wire down events and reduces current to levels that decrease the risk of fire ignition.
- EPIC 3.20: Maintenance Analytics - Big data analytics that leverage Advanced Metering Infrastructure (AMI), Supervisory Control and Data Acquisition (SCADA), GIS, weather and other data to identify assets at imminent risk of failure, and enable proactive maintenance.
- EPIC 3.21: Vegetation Analytics - Leverage Light Detection and Ranging and other remote sensing data already collected by PG&E to develop an analytical tree-specific risk index.
- EPIC 3.11: Location Targeted DERs - Enhance PG&E's understanding of communication and control requirements to enable the effective implementation of multi-customer microgrids.

Security

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 in the fourth year of executing the five-year California Energy Systems for the 21st Century (CES-21) Program in partnership with Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Lawrence Livermore National Laboratory (LLNL). CES-21 is a research effort with the primary objective of exploring the next generation of Industrial Control Systems cybersecurity and developing the foundation for Machine-to-Machine Automated Threat Response. Research programs such as CES-21 leverage IOU, academic, and/or private sector expertise can further strengthen PG&E's grid security in light of increased threats.

PG&E is positioned to address the risks presented by the evolving Utility business and Smart Grid technologies. For more information on Security developments, please reference report Section 2.13 (Key Risks Overview).

Customer Service

Over the past year, PG&E has made steady progress on 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.

One area that PG&E made significant progress around for customer service surrounds EV enablement. PG&E's furthered its' EV Charge Network Program, 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 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 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent.

The program will scale to completion in 2019 and 2020. For further project information, see the Electric Vehicle Charge Network (EVCN) Quarterly Report: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page.

DER Integration and enablement

A. Managing DER Effects on Distribution System

Balancing loads between three phases on the distribution grid becomes challenging with higher DER penetration. Considerations include the effects of DERs' output, location and characteristics on the distribution grid to mitigate issues such as phase imbalance and voltage regulation problems. PG&E is investing in the Smart Grid to establish more sophisticated planning and operational tools to detect and predict grid issues.

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 data analytics capability is the EPIC 2.22: Demand Reduction through Targeted Data Analytics technology demonstration. This project developed and demonstrated an affordable and scalable solution that positions PG&E as the industry leader in integrating DERs into Distribution Planning, by optimally identifying where targeted procurement of DERs can have grid benefits. The core of this solution is a parallelized mixed-integer linear optimization model, which identifies the most cost-effective portfolio of solutions capable of solving a feeder overload (including DERs or wires alternatives). This analytical approach draws on over a dozen data sources and can match customers to nearly 100 different EE, DR, Distributed Generation (DG) and energy storage technology options, based on personalized propensity scores. EPIC 2.22 builds on the progress made in a prior PG&E EPIC demonstration project, EPIC 2.23: Integrate Demand Side Approaches into Utility Planning.[3] EPIC 2.23 enabled PG&E to ensure it is better incorporating deployments of DERs that customers are undertaking voluntarily in response to rates, incentives or other benefits into its distribution planning process. EPIC 2.22 utilizes data and inputs from EPIC 2.23, including load shape profiles and enhanced load forecasts, to further PG&E's understanding of optimal locations for procurement of DERs to maximize customer value.

B. Situational Awareness

To realize the value of DERs, the distribution operator will need enhanced visibility & control to validate and ensure DER performance meets grid needs. PG&E is investing in the Smart Grid to establish greater granular visibility into the distribution system, including tools for:

- Predicting DER behavior
- Viewing real time DER response
- Forecasting DERs' impact on the grid

To enable the optimization 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

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3 Read more about the EPIC 2.23 project in the EPIC 2.23 Final Report – https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.23.pdf.

DERs, particularly third-party-aggregated DG and storage resources. The DERMS demonstration gives PG&E a strong grasp of how capabilities fit together and what capabilities PG&E will need to manage an increasingly complex distribution grid while enabling new value streams from DERs, including:

- New operational capabilities and applications (ADMS)
- Foundational data model and system improvements in order enable these applications
- Monitoring and communications to provide necessary DER visibility
- Standardized and secure integration with DERs

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.

Smart Inverters Technology for Enhanced Situational Awareness

Smart Inverters convert power from solar panels and batteries from its native direct current into alternating current (AC) which can be used on site or fed into the power grid. A SI is a more sophisticated version of an inverter that makes autonomous decisions that can help maintain grid stability, reliability and power quality. Through EPIC 2.03A: Test Capabilities of Customer-Sited Behind the Meter SI, PG&E demonstrated the use of residential customer-sited PV SI technologies and communication infrastructure to mitigate potential local grid issues related to high penetration of customer-sited DERs on two electrical distribution feeders ("Location 1"). This demonstration project evaluated a vendor-specific SI aggregation platform, communications reliability to the SI assets, and feasibility of targeted customer acquisition for

DER deployment. PG&E is still working on a demonstration on one additional feeder ("Location 2"). These ongoing project activities are specifically targeting high voltage issues attributed to Location 2's high PV penetration and an evaluation of a vendor-agnostic aggregation platform to remotely monitor and make settings changes to the SI assets. Testing at Location 2 of the project is expected to be completed in late 2018.

C. Customer Enablement

PG&E's Distribution Resources Plan

Since PG&E's DRP filing in July 2015, PG&E has continually advanced its distribution planning and interconnection processes and tools to more effectively enable customers through the integration of DERs into the distribution grid. Over the last few years, PG&E has worked closely with the CPUC and external non-utility stakeholders on topics such as on DER Integration Capacity Analysis (ICA), process for identifying non-wires alternative solutions and grid modernization for DER enablement. Select examples through which PG&E is enabling customer DER interconnection enhancements are provided below.

Integration Capacity Analysis

Starting July 31, 2018, PG&E (and other California IOUs) will post ICA results for their distribution system on their DRP data portals, which will be updated on a monthly basis, and will inform DER stakeholders on expected available distribution grid capacity to host DERs. PG&E is also working with the CPUC and external non-utility stakeholders on developing opportunities to leverage ICA in streamlining and enhancing transparency of interconnection results for the Rule 21 generation interconnection process.

Distribution Investment Deferral Process for Identifying Non-Wires Alternative Solutions

On June 1, PG&E (and other California IOUs) published its first annual electric distribution Grid Needs Assessment (GNA) report, which was mandated in the CPUC's DRP decision related to the distribution investment deferral framework. PG&E's initial GNA report identifies projected distribution grid needs over the next 5 years and was focused on substation level capacity level needs. Future iterations of the GNA reports will include additional distribution grid granularity beyond substation level capacity needs, including voltage support, reliability and resiliency.

By September 1, 2018, after incorporating input from the CPUC and stakeholders on the PG&E's initial GNA report, PG&E publish a Distribution Deferral Opportunities Report (DDOR), which will identify locations on PG&E's distribution grid where non-wires alternative solutions may be a feasible and cost-effective solution compared to traditional "wires" solutions. Shortly after publishing the DDOR, PG&E will convene a Distribution Planning Advisory Group (DPAG), which is an independent planning advisory group that will provide advisory input to PG&E on the process it used in developing the DDOR and identifying and prioritizing potential distribution deferral opportunity locations for non-wires alternative solutions.

By December 1, after incorporating DPAG input, PG&E will finalize its distribution investment deferral opportunities list and submit an Advice Letter to the CPUC requesting approval to proceed with hosting competitive solicitations for non-wires solutions to address select grid needs through non-wires alternatives.

CHAPTER 3

PG&E'S SMART GRID DEPLOYMENT PLAN

AND PROJECT UPDATES

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

Pursuant to Decision (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 2017 through end of June 2018) and its progress on its Smart Grid Deployment Plan.[4]

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.[5]

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.[6] For convenience of review, PG&E's Smart Grid investments are combined in this Annual Report.

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4 Unless otherwise specified, PG&E has provided cost and benefits for all projects for the period beginning July 1, 2017 through June 30, 2018.

5 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.

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

3.1. 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-, Lesbian, Gay, Bisexual, and Transgender (LGBT) – and service-disabled veteran-owned business enterprises (collectively, Diverse Business Enterprises or "DBEs") into its supply chain. In 2017, PG&E spent $2.6 billion with diverse businesses for a 42.25 percent total DBE spend. PG&E continues its demonstrated success in DBE outreach, development and partnership in all categories of procurement, including Smart Grid.

3.2. Summary of Benefits for Select Projects

This year, PG&E's Smart Grid benefits continued to grow, adding an estimated $197 million of incremental savings from July 2017 through end of June 2018 for select projects (shown below).

Table 1-1: PG&E's Smart Grid Estimated Project Benefits – July 2017 to June 30, 2018[7]

Category	Annual Savings
Direct Customer Savings (Demand Response)	$255.1 Thousand
Avoided Costs (Operational, Capital, Environmental[8])	$3.2 Million
Customer Reliability Benefit[9]	$193.5 million[10]
Total Benefits	**$197.0 million**
Reliability	72.2 million customer minutes avoided[11]

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

- PG&E's SmartMeter Outage Information Improvement ($0.6 million)
- PG&E's Bill Forecast Alerts (formerly: Energy Alerts)[12]

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7 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.

8 For details on PG&E's Environmental developments, please see PG&E's Corporate Sustainability Report at: http://www.pgecorp.com/corp/responsibility-sustainability/corporate-responsibility-sustainability.page.

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

10 Customer Reliability Benefit for Fault Location, Isolation and Service Restoration (FLISR) since inception is $808.5 million, with 303.8 million customer minutes avoided.

11 FLISR has enabled the following statistics for Customers Experiencing Sustained Outages (CESO), avoided outage minutes, and Customer Minutes of Interruption (CMI), respectively:

- Avoided Customer Sustained outages over reporting period: 744,938 (CESO)
- Actual recorded outage minutes over reporting period: 171,853,823
- 5-year average recorded outage minutes: 129,383,524 (CMI)
- 5-year average avoided outage minutes: 59,136,153 (CMI)

12 The quantifying methodology for this project is aligned with the methodology used in the 2017 Smart Grid Annual Report. Since the 2017 analysis for this program the 2017 OP 10 (SmartMeter Program Enabled Demand Response and Energy Conservation Annual Report) proved inconclusive, the avoided energy consumption is not provided as a quantified benefit. Benefits for this program target the Residential customer segment.

- PG&E’s Automated DR Program ($255.1 thousand)
- PG&E’s FLISR project ($193.5 million)
- PG&E’s Modular Protection and Automation Control (MPAC) project ($2.6 million)

<u>Benefits Descriptions</u>

Direct Customer Savings (Bill Forecast Alerts/Automated Demand Response (ADR))

Bill Forecast Alerts (BFA) estimate what a customer’s bill will be (gas and electric) and alerts them when the forecasted amount exceeds their custom-set threshold. Because forecasts are predictions, estimates may differ from the customer’s actual charges for each statement period. PG&E’s current BFA replaced the former Tier Alerts in March 2016 in anticipation of E1 tier collapse and new Time-of-Use (TOU) rates coming on-line. Additionally, gas usage was added to the forecast for a more complete customer experience. Many customers have been receiving alerts (both Tier and then the Bill Forecast Alert) for 7 years. Early savings results from the programs were a result of initial awareness of household costs associated with energy usage and initial meaningful adjustments made to control this. PG&E’s *2017 Program Year SmartMeter Program Enabled Demand Response and Energy Conservation Annual Report* concluded that quantified savings results from this program were inconclusive using past and existing analytical techniques, as self-selection bias was suspected to disrupt the ability to estimate the true relationship between alerts sent as part of BFA, and participant consumption. Benefits for this program are not quantified for the 2017 program year, for purposes of the Smart Grid Annual Report. The program continues to serve customers by providing them with a transparent billing alert and helps customers to manage energy cost with consumption patterns.

Automated DR benefits result from load reductions. For the benefits assessment included in the Smart Grid Report, DR Program compensation was based on the Program rate of $0.50/kilowatt-hour (kWh). More information on the benefits calculation for this project can be found in the ‘Automated Demand Response (ADR) Program’ program box in the *Emerging Customer Side Technology Projects* section of this report.

Avoided Costs (SmartMeter Outage Information Improvement/MPAC)

Avoided cost benefits represent the total avoided costs associated with SmartMeter Outage Information Improvement and 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 8,000 "truck rolls," saving over $600,000 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 $2.6 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $64.6 million.[13]

Reliability Benefits (FLISR)

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 that was developed in-house using the Freeman & Sullivan analysis incorporating various tax law changes. FLISR procedures have been updated to account for fire index disabling, under which select FLISR circuits may be disabled on extreme fire condition days.

Smart Grid's Role in Furthering Environmental Sustainability

California has adopted the strongest greenhouse gas (GHG) reduction targets in North America. SB 32 requires the state to cut GHG emissions to 40 percent below 1990 levels by 2030. SB 350 mandates a goal of doubling EE savings by 2030. As California's largest energy provider, PG&E is committed to helping California achieve these goals.

Smart Grid technologies enable numerous environmental benefits. Over three hundred thousand customers have installed roof top solar and generate their own power. Nearly two hundred and fifty thousand customers have decided to replace their traditional vehicles

[13] MPAC benefit totals reflect updated calculations for 2018 Smart Grid Annual Report.

with EVs fueled by the smart grid. Smart grid technologies, including sensing technologies, two-way digital communication, controls and automation, all provide foundations for which new DERs can be connected and controlled via the grid. Given the intermittency and flexibility of DERs like solar and EVs, PG&E's ability to communicate with such assets and in some cases, determine whether it generates or uses energy enables GHG reductions while building a more reliable and resilient grid.

For more information on environmental developments at PG&E, please view PG&E's Corporate Sustainability Report at: http://www.pgecorp.com/corp/responsibility-sustainability/corporate-responsibility-sustainability.page.

3.3. 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. The projects that PG&E has implemented, focus on areas such as customer engagement and empowerment, Asset Management and Operational Efficiency, Transmission and Distribution (T&D) automation and reliability, safety, cybersecurity, and integrated and cross-cutting systems. PG&E and the industry continued to gain additional information and knowledge because 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.

3.4. Customer Engagement and Empowerment Projects

Over the reporting period, PG&E has made steady progress on many projects to provide customers with tools necessary to manage their energy usage and costs. 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. By supporting adoption of EVs, PG&E can extend efforts to reduce GHG emissions across the state.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2017 through June 30, 2018, unless otherwise noted.

3.4.1. Demand Response Projects

Supply Side II DR Pilot (SSP II)	**Approximate Cost Over Reporting Period:** **$0.63 Million**
Description: The Supply Side II DR Pilot (SSP II) continues the work started in previous DR pilots to enable participation of customer behind-the-meter DERs as DR in the wholesale energy market using the Proxy Demand Resource (PDR) wholesale product. In addition, the SSP II in 2017 was expanded to start investigating the ability of wholesale DR to also 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 in 2017 was approved by the CPUC in D.16-06-029, and the CPUC subsequently approved 3 additional years of funding (2018-2020) in D.17-12-003. Status: Participants have been bidding into the wholesale energy market. Between April 2015 and June 2018, pilot participants have submitted over 11,200 bids and received over 1,500 awards in the wholesale day-ahead energy market. While the pilot is open to residential aggregators, and several have gone through various stages of the enrollment process, to date none have completed the process and all participants are commercial customers or aggregators. In 2017, the SSP II started investigating the operational feasibility of utilizing DR resources that are integrated in the wholesale energy market to also address local distribution needs. As part of this work, the SSP II was used in conjunction with PG&E's EPIC 2.02 (DERMS) project to test if an aggregation of behind-the-meter DERs could respond to both wholesale and distribution instructions with no negative impact to the safety and reliability of the grid. While work with EPIC 2.02 has ended, the SSP II is continuing to investigate this issue. Benefits Description: The SSP II is a gateway for more DR resources to be integrated into the California Independent System Operator (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 to have a self-sustaining third-party DR market in California. Learnings from the pilot were integrated into PG&E's proposed enhancements to its Capacity Bidding Program (CBP) included in its 2018-2022 DR Application, and future results from the SSP II, in addition to inputs from the Distributed Resource Plan and Integrated DERs proceedings, may be used to inform a proposal for distribution service offerings in future DR programs. The SSP II also provides a pathway for new technologies. Technologies behind the customer meter, such as storage, EVs, and or Smart devices, can play a vital role as grid-responsive assets.	

DR programs will act as avenues for participants to provide demand reduction based on the needs of the CAISO and distribution systems. 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 behind-the-meter technologies.

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 T&D system operators will need in the future.

Excess Supply DR Pilot (XSP)	Approximate Cost Over Reporting Period: $0.58 Million

Description: There has been much written about the changing net load curve, where the "net load" is the total system load minus the renewable generation. This change from the conventional mid-day peak, due in large part to the increased penetration of renewables, dramatically impacts the system operational needs. This is often referred to as the "duck curve." Not only have the net load profiles changed in recent years, they fluctuate substantially over the course of a year. This demonstrates the importance of a flexible solution that can be adapted to fit the ever-changing load profiles. These changes in net load, policy, and technology, create challenges to the grid in balancing against the capacity in T&D and require California to evaluate which market constructs and resources can address future grid needs. Examples of policy tools available to solve ramping issues include TOU pricing where retail rates are aligned with wholesale grid conditions, exporting electricity during periods of excess supply, curtailing renewable resources, or incentivizing customers to shift load on-demand when needed by the grid.

PG&E's Excess Supply DR Pilot (XSP) is investigating ways to incentivize customers to shift energy usage as a possible way to mitigate these challenges. In the XSP, demand responsive loads are being considered as one of the many resources that can support in-state economical and reliability needs of the future grid. The XSP is a departure from other offerings in that it asks participants to shift energy usage to consume more energy at certain times to help mitigate situations of excess supply on the transmission and/or distribution systems as well as in the case of negative wholesale energy prices. By getting customers to shift their energy consumption to align with periods of excess supply, the XSP hopes to demonstrate that customers can actively assist with renewables integration and improve alignment of supply and demand.

Funding Source: The XSP was originally approved by the CPUC as part of the 2015-2016 DR funding bridge D.14-05-025). Funding for this pilot in 2017 was approved by the CPUC in D.16-06-029, and the CPUC subsequently approved 3 additional years of funding (2018-2020) in D.17-12-003.

Status: The XSP was initiated in 2016 and was approved by the CPUC to continue through at least 2020. Currently there are four non-residential customers fully enrolled with several other participants that have completed part of the enrollment process. To date, larger commercial customers, and 3rd parties aggregating larger commercial customers, have generally been more interested in participating in the XSP than small commercial and residential customers.

The XSP is an out of market pilot as there is currently not a mechanism at the CAISO to register or bid these resources. This may change for some resources as the CAISO is developing a load shift product for behind-the-meter battery resources and a technology neutral approach to a load shift product is under development as a part of the CPUC's investigation of new models of DR as a part of the Load Shift Working Group. Pilot events were dispatched based on administrative decisions to test the overall construct of response to excess supply conditions, not based on actual grid conditions.

The XSP has been successful in gaining learnings in many of its key objectives and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. However, there are still unanswered questions around what should trigger an excess supply event, the effects on customer bills, the effects on local distribution operations, and the interaction with other DR programs that provide demand and energy reductions.

Upcoming Plans (Subject to Change): In addition to continuing to gain insights into the previously mentioned issues, the XSP is being modified with the aim of enabling bi-directional dispatch in a single program, limiting availability periods to the times of day with the highest probability to encounter excess supply and negative wholesale prices, and modifying the event trigger mechanism.

Starting in 2018, site hosts in PG&E's EVCN program can meet the EVCN's load management plan requirement by participating in the XSP, and the XSP program is beginning the process of enrolling new participants from the EVCN program. Including EVCN participants in the XSP will enable the pilot to incorporate a technology (EVs) and customer classes (smaller commercial and multi-unit residential) that have been absent from so far.

Benefits Description: PG&E envisions that the XSP ultimately will be a program offering that will assist during excess supply conditions. The XSP is meant to explore how customers can help mitigate situations of excess supply on the transmission and/or distribution systems as well as in the case of negative wholesale energy prices, by shifting their load consumption to these periods and contribute to the improved alignment of supply and demand. Learnings from the XSP have helped inform ongoing proceedings at the CPUC and CAISO, including the CAISO's Energy Storage and Distributed Energy Resource stakeholder process and the CPUC's investigation of new models of DR as a part of the Load Shift Working Group.

The XSP also provides a pathway for new technologies. PG&E believes that technologies adopted behind the customers' meters, such as storage, EVs, and smart devices, can play a vital role as grid-responsive assets to help with excess supply situations.

DR programs will act as avenues for participants to provide load shifts that are tied to when there is excess supply on the grid. Results of the XSP will help PG&E, the CPUC, and the CAISO assess the benefits of DR as a gateway to grid needs and benefits and, in addition, provide an in-depth understanding of the benefits of behind-the-meter technologies.

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 through improved alignment of supply and demand. PG&E is pursuing discovery of the necessary program attributes that T&D system operators will need in the future.

AC Cycling	**Approximate Cost Over Reporting Period:** **$7.2 Million***

Description: Under its direct installation program, SmartAC™, PG&E has deployed over 250,000 1-way paging air conditioner direct load control devices since 2007. To leverage its investment in the AMI network and to improve the reliability of this resource, PG&E conducted extensive testing and has migrated to a bidirectional (2-way) technology by Energate (recently acquired by Tantaulus) that communicates through Smart Meters. This new technology communicates with PG&E's SmartMeters via a Zigbee Smart Energy 1.1b standard protocol module. Residential Smart Meters at PG&E incorporated this auxiliary communication module since initial deployment to promote Home Area Network and smart grid automation. PG&E has integrated the 2-way device head-end control system, Itron's (formerly Silver Spring Networks) Home and Business Area Network (HAN) Communication Manager, with its DR management system, Lockheed Martin Energy's SEEload product, to have a single system of dispatch to support CAISO market integration of its SmartAC program in 2018 and provide a graphically based dashboard of enrollment and dispatchable status. Funding Source: Funded through a balancing account authorized by the Commission in D.17-12-metric 003. *Includes marketing, administrative, and device costs Upcoming Plans (Subject to Change): PG&E has currently deployed nearly 8,000 2-way load control switches. Deployment plans do not entail mass replacement of legacy 1-way technology but rather if existing devices are malfunctioning, they will be replaced. The SmartAC program is currently in a mode of recruiting new customers to back-fil for attrition and has been approved through 2022 at this level which equates to roughly 10-12,000 customers annually. While PG&E has built out meter level real-time visibility for enrollment and dispatchability, future enhancements incorporate real-time load control device level status visibility. 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. By installing two-way direct load control devices, PG&E has near real-time visibility into an individual premise and the air conditioner's actual response to a load control event signal. This facilitates 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.

3.4.2. Electric Vehicle Integration Projects

Electric Vehicle Infrastructure	**Approximate Cost Over Reporting Period:** **$12.0 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 2018, PG&E is scaling the program after launching in January 2018. As of June 30, 2018, PG&E had received 256 applications for the program. At the close of Q2 2018, 56 sites had been approved and moved into final design and pre-construction phases, including 3 sites that have completed construction, installation, and activation of chargers. PG&E has installed 80 ports as of June 30, 2018. PG&E is also conducting solicitation processes for EV chargers. Quarterly Request of Quotations are held for the Charge Owner model (Site Host ownership) and a single Request for Proposal (RFP) is being held for the Charge Sponsor model (PG&E ownership). The program will scale to completion in 2019 and 2020. For further project information, see the EVCN Quarterly Report: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page.

Upcoming Plans (Subject to Change): see program status for details of upcoming plans.

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 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, 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

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; 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 45,000 customers on the EV rate, representing 25-30 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 Center for Sustainable Energy, 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 enrolment 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://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455828). Upcoming Plans (Subject to Change): PG&E proposed in its recent 2017 GRC Phase 2 to remove the enrollment cap on the EV rate and allow residential battery storage customers to take service on the EV rate. PG&E is also developing an EV rate proposal for commercial customers that aims to support public charging and medium- and heavy-duty fleet electrification. Benefits Description: The current off-peak price for electricity on the EV rate $0.13/kWh, equivalent to approximately $1.30/gallon of gasoline. This low off-peak price allows EV drivers to realize significant fuel cost savings compared to gasoline, which is currently trending above $3.50 per gallon in California. Because 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 behaviours 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.

3.4.3. SmartMeter Enabled Tool Projects

Energy Diagnostics and Management (includes, Home Energy Reports, Business Energy Reports, My Energy Portal)	**Approximate Cost Over Reporting Period: $3.8 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 (SMBs). 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 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. Upcoming Plans (Subject to Change): Consideration for solar options for PGE customers to save and produce their own energy is being explored. 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.

Bill Forecast Alerts (formerly: 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 a supported rate plan (HG1, HE1, HE6, HE7, HE8, HE9, HEA9, HEB9, HEVA, HEVB, HETOUA, HETOUB, HETOUC, G1, E1, E6, E7, E8, E9, EA9, EB9, EVA, EVB) are eligible. The following classes of customers are not supported: DA, Community Choice Aggregation (CCA), and Net Energy Metering (NEM). 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: In March of PY 2016 Energy Alerts transitioned into BFAs. BFA replaced the Tier Alerts with an alert that warns customers when they reach their user-specified dollar amount threshold. Customers are subsequently notified with an alert via their channel of choice (email, phone, or text message) when they meet their designated threshold amount up to one day prior to the end of their billing cycle. BFA is only available for residential customers who are SmartMeter read and billed. Customers could enroll in Energy Alerts, or currently BFA, online via the Your Account web site. During the past few years, PG&E has marketed Energy Alerts and BFA in a similar manner as Customer Web Presentment (CWP) and often in parallel with CWP and Your Account communications. In December 2013, the Your Account homepage was redesigned, which made it easier for customers to connect to other often-used functions, such as analyzing usage, comparing rate plans, and signing up for Energy Alerts. From 2014 through 2017 enrollments continued to increase, most likely due to greater customer awareness of PG&E's digital services accessible through the Your Account website. In December 2017, BFA reactivated Marin Clean Power and Sonoma Clean Energy customers who had been enrolled in BFA prior to transitioning to their CCAs. Though CCA customers have been ineligible for new BFA enrollments due to rate modelling limitations, PG&E is exploring ways to open enrollment into BFA to new CCA customers. In February 2017, PG&E added to its product offering the High Usage Alerts (HUA) program. This program sends out an early warning notification when customers are projected to trigger a surcharge. The High Usage Surcharge is incurred when	

customers exceed four times their Baseline Allowance. HUA is only available for residential customers with electric service through a SmartMeter and are on eligible tiered rate plans. Similar to BFA, customers could enroll in HUA online via the Your Account website. As part of the implementation of the High Usage Surcharge, PG&E sent letters to customers who were at risk of the surcharge or had incurred it. The HUA program was featured in these compliance letters, which helped drive some of the enrollments into the program.

In 2017, a total of 77,987 customers enrolled in the HUA program. However, only 15,181 of these customers received an alert in 2017. These counts also include participants, who are enrolled in other PG&E programs such as CWP, BFA, SmartRate™ and SmartAC. As with BFA, the analysis population excludes SmartAC and SmartRate customers, participants who received alerts on more than one media type, and those who did not receive an alert in 2017. The analysis population was also segmented into singly-enrolled HUA participants and participants dually-enrolled in BFA and HUA. As a result, the HUA analysis population consists of 6,669 singly-enrolled participants and 6,184 dually-enrolled participants, for a total of 12,853 analyzed HUA participants in 2017.

Benefits Description: Bill Forecast Alert provides enrolled customers with a monthly projected bill amount notification when their current usage pattern is expected to exceed their personalized threshold amount. This alert will help customers adjust their consumption patterns to avoid paying higher energy bills or financially plan for their estimated bill amount.

Benefit Category: Engaged Customer.

Benefit Quantification Methodology: The evaluation was conducted in five basic steps. The results proved inconclusive for Fiscal Year 2017 (FY2017) as detailed in the PY 2017 Evaluation of BFAs and HUAs report.

Full Report: PY2017 Evaluation of BFAs and HUAs. CALMAC ID PGE0418 Applied Energy Group, Inc. 2018. 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: $4.7 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, operation and maintenance for this project is funded through GRC.

*The Click Through Project is funded by D.16-06-008 and covers both Share My Data related updates and specific changes to better support Electric Rule 24 process for DRP.

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 in December 2015. On August 25, 2017, the CPUC approved PG&E's Advice Letter (AL) 4992-E in compliance with OP 10 of D.16-06-008 to deliver Click Through with Resolution (Res.) E-4868. PG&E launched Click Through Phase 1 to comply with Res. E-4868 on February 22, 2018 and Phase 2 on June 28, 2018. This project was to provide improvements to the Electric Rule 24 process for DRPs to obtain customer authorization to access the customer's data for direct participation in the CAISO's wholesale market. This also included simplifying the overall electronic authorization process via the Share My Data platform. Upcoming Plans (Subject to Change): PG&E is currently planning to deliver Click Through Expanded Data Set in Q3 of 2018 and Phase 3 in Q4 of 2018. 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:** **$0.2 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.[14] Funding Source: Through December 2016, PG&E was tracking the incremental costs associated with implementing this decision in a memorandum account and was seeking authorized recovery of such costs through its GRC proceeding. As of January 2017, operation and maintenance for this project is funded through GRC. 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). An updated data request log (data catalog) is provided below and summarizes the requests worked on during the period July 1, 2017 through June 30, 2018. The complete log can be viewed on PG&E's website at http://www.pge.com/energydatarequest. The EDAC was required to hold quarterly meetings through December 2016 and thereafter meets only on an 'as needed' basis. Minutes from each meeting are	

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

posted on the CPUC's EDAC website: http://www.cpuc.ca.gov/General.aspx?id=10151. For further project information see: Quarterly Advice Letters (Latest filing: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_3964-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.

PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2017 – 6/30/2018)

Organization	Requestor Type	Description	Status	Change Date
County of San Luis Obispo	Local Government	Aggregated data on EE program and solar implementations for a County specified set of seven-digit zip codes.	Approved – In Progress	6/19/2018
County of San Luis Obispo	Local Government	Anonymized data on total monthly billed usage (kWh), heat type, and master meter for a County specified set of seven-digit zip codes.	Approved – In Progress	6/11/2018
Yale University	Academic Researcher	Details still TBD but will involve extensive usage, billing, program participation, and location data for customers in a series of cities (to be determined by Yale).	Paused	6/11/2018
Yale University	Academic Researcher	[Duplicate Request]	Canceled/Withdrawn	5/30/2018
PESD; Stanford University	Academic Researcher	Billing and interval data for residential customers, plus street address, rate code, and California Solar Initiative (CSI) and EE program usage.	Paused	4/20/2018
Pacific Northwest National Laboratory	State or Federal Agency	Electric usage and billing by census block, plus meter type and multifamily information.	Canceled/Withdrawn	4/10/2018
University of California, Davis (UCD) Center for	Academic Researcher	7 years historical gas billing and interval data or monthly usage if interval data not available, including	Downloaded	4/4/2018

Organization	Requestor Type	Description	Status	Change Date
Water-Energy Efficiency		premise addresses, for zip codes in Modesto: 95350, 95351, 95354, 95355, 95356, 95357, 95358, 95380, 95363, and 95368		
Energy Institute at Haas	Academic Researcher	Agricultural water pumping study	Downloaded	3/20/2018
Duke University	Academic Researcher	2011-2017 annual household usage for residential customers by zip codes as provided by the requester, with flags for customers on Net Energy Metering rate.	Downloaded	3/14/2018
Energy Institute at Haas	Academic Researcher	Reliability study combining customer specific outage data with other customer characteristics for selected zip codes and a random, control sample.	Downloaded	3/13/2018
City of Hayward	Local Government	Customer Class, Number of Customers, City, zip Code, Commodity (Gas or Electricity), Month Start Day, Month End Day, Monthly Billed Usage, Heat Type. Data is aggregated to zip Code level.	Downloaded	3/9/2018
City of Arroyo Grande	Local Government	Aggregate electric usage by zip code, by sector, by year.	Downloaded	3/2/2018
San Francisco Dept. of Public Health	Local Government	2014-2017 residential gas and electric usage	Downloaded	3/2/2018
Yale Department of Economics	Academic Researcher	Anonymized monthly electrical usage for solar customers and for a random sample of non-solar users.	Approved – In Progress	3/2/2018
UCD Center for Water-Energy Efficiency	Academic Researcher	[Duplicate Request]	Canceled/Withdrawn	2/26/2018
Purdue University	Academic Researcher	Solar PV related data including the precise address of each installed solar PV project in your database.	Canceled/Withdrawn	2/16/2018

Organization	Requestor Type	Description	Status	Change Date
University of California Los Angeles	Academic Researcher	Price of electricity (residential) for each zip code. Description of different rate plans if they vary	Canceled/Withdrawn	2/15/2018
		Net-metering rate by zip code		
		Usage, location, net-metering application ID and amount of credited energy for each net-metering household		
University of California, Irvine	Academic Researcher	– Residential solar customer information: street address or geographic coordinates. Billing history, rate schedule, usage data.	Downloaded	2/15/2018
		– Program participation: CSI and other programs to promote sustainable energy use.		
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg Air Force Base (AFB), for 2015	Suspended	2/5/2018
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg AFB, for 2017	Suspended	2/5/2018
County of Santa Barbara	Local Government	GHG reporting for the unincorporated county, not including Vandenberg AFB, for 2016	Suspended	2/5/2018
City of Cupertino, Sustainability Div.	Local Government	Disaggregated, randomized, and anonymized meter level gas and electric energy usage data in monthly intervals, and data flags, grouped by census block group for specified block groups.	Downloaded	1/25/2018
Energy Institute at Haas	Academic Researcher	DR Aggregator study: 2014-2017 residential billing and interval usage; participation in CCA, EE and DR SmartRate programs for random	Downloaded	11/20/2017

Organization	Requestor Type	Description	Status	Change Date
		sample of residential customers, and total count of customers per zip code		
Tulare County	Local Government	2016-2017 Usage data from Tulare County's account for their government operations and aggregated community data for residential, commercial, and industrial customers in unincorporated Tulare County.	Canceled/Withdrawn	11/13/2017
University of Virginia	Academic Researcher	2012-2017 Interval and billing data for non-residential and multi-family buildings in Alameda, Contra Costa, San Francisco, Sacramento, San Joaquin, Santa Clara, Santa Barbara, San Mateo	Suspended	11/10/2017
Placer County CDRA	Local Government	Energy usage data for Unincorporated Placer County.	Canceled/Withdrawn	10/9/2017
University of San Francisco	Academic Researcher	All addresses in the county of San Francisco that currently have installed solar PV systems connected to the PGE net metering system. What is the system capacity, date that the system was brought online and the vendor of that system.	Canceled/Withdrawn	9/29/2017
City of Fresno District 1	Local Government	Electricity usage for the Fresno Tower District.	Paused	9/19/2017
LBNL	Academic Researcher	LBNL request for usage data for Property Assessed Clean Energy participants	Canceled/Withdrawn	8/21/2017
City of Union City	Local Government	Total annual electricity and natural gas usage data for Residential and Commercial/Industrial, and also for city facilities and Streetlight & Traffic Signals. Data requested for climate action or EE program planning	Canceled/Withdrawn	8/16/2017

Organization	Requestor Type	Description	Status	Change Date
Town of Portola Valley	Local Government	2014 and 2015 energy usage data solar installations EVs	Canceled/Withdrawn	8/16/2017
City of Oakland	Local Government	2015 community gas and electric energy use, under EDRP approved aggregation	Canceled/Withdrawn	8/3/2017

Stream My Data – Home and Business Area Network (HAN)	**Approximate Cost Over Reporting Period:** **$0.44 Million**

Description: PG&E's Stream My Data helps customers save energy and money by providing real-time (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 can do the following:

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

Funding Source: The funding source was based primarily from GRC funding.

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. Over the timeframe of April-May, PG&E experienced an outage of Stream My Data service on the PG&E website, triggered by back-office IT infrastructure security patch upgrades. This affected all customers Stream My Data service returned on June 7 together with an upgraded user interface.

Some commercial energy management solution providers have started to show Interest in Stream My Data for commercial buildings, and so PG&E offers limited support to vendors who wish to trial Stream My Data functionality on a small scale.

Upcoming Plans (Subject to Change): Stream My Data is being revised to enable access to electrical usage for all residential smart meters, regardless of rate plan. PRICE information availability will remain the same for the limited set of rate plans.

Benefits Description: Customers can 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: $0.4 Million

Description: The Building Benchmarking Portal (BBP), created in compliance with Assembly Bill (AB) 802, is a web-based system for building owners, or their authorized agents, to request aggregate whole-building energy usage data uploaded into their Energy Star Portfolio Manager accounts. The BBP is a streamlined service for procuring building energy 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 GRC 2020 Rate Case. Upon review and approval by the CPUC, PG&E will transfer the AB 802 MA balances to the appropriate balancing accounts, as directed by the Commission, for recovery in rates.

Status: At the end of Q2 in 2018, the BBP has received over 2,300 requests for building energy usage data. Most requests were likely driven by the California Building Energy Benchmarking Program, which requires certain buildings to report and submit their building's energy usage data to the CEC. 2018 is the initial year building owners are required to submit energy usage data to the CEC.

Upcoming Plans (Subject to Change): User adoption and the amount of buildings "benchmarked" with the BBP is expected to grow, due to the CEC Benchmarking requirements, as well as Normalized Metered Energy Consumption EE savings programs. Additionally, future legislative and/or regulatory updates may prompt slight augmentations to the BBP. However, core functionality of the BBP is not anticipated to change.

Benefits Description: The BBP streamlines the procurement of energy data for benchmarking. Additionally, tenant turnover is not nearly as impactful on the benchmarking process. Per AB 802, if a non-residential building has 3 or more active utility accounts, or a building has 5 or more active utility accounts with at least one residential account, individual meter authorizations are not required. As more building owners 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 resilient portal, the BBP will allow building owners to more easily track and manage building 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 25-40 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 is at 113,000 residential customers as of July 2018 and provides an average of 20-25 MW of load reduction on event days. Please note we do anticipate a drop-in enrollment by end of season due to CCA's that could impact the overall MW average for 2018.

Over 439,000 SMB Service Agreements have transitioned to TOU rates in the past six years. 160,000 Service Agreements are active participants in the PDP Program as of July 2018. PG&E continues to build off the success of PDP's Enhanced in Season Support with over 50,000 SMB Service Agreements receiving emails and nearly 2,000 business customers enrolled in text messaging. Businesses enrolled in text alerts, on average, doubled their energy savings vs. email.

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.

3.4.4. Emerging Customer Side Technology Projects

Automated Demand Response (ADR) Program	Approximate Cost Over Reporting Period: $4.1 Million

Description: PG&E's ADR program offers small, medium and Large Commercial, Industrial and Agricultural customers (LC&I) an incentive to install automated equipment that enhances their ability to reduce load during DR events. Specifically, ADR 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 in-turn enables them to participate in a DR event day.

Funding Source: Since its inception, PG&E's ADR program has been funded under PG&E's DR activities and budgets, which have been authorized by the Commission. The Commission has approved the 2018-22 application for ADR and ordered PG&E to continue to offer the program to its customers.

Status: PG&E's ADR program currently offers incentives to LC&I; SMB; and Residential customers. Through the Demand Response Emerging Technology initiative, the ADR program is looking at other technology controls that it can support in the future.

Benefits Description: Customers receive many benefits from participating in the ADR Program including, but not limited to, the ease of participation in a DR event due to the ability of being able to automatically control the technology controls for which an incentive has been received from the ADR Program. Each time a customer participates in a DR event, they also receive compensation for the realized load shed. Compensation varies depending on which DR program the customer chooses to enroll in. It is especially variable when working with an aggregator as that compensation level is decided between the customer and the aggregator. In 2016-17, the assumption of DR program compensation was based on the Demand Bidding Program (DBP) program rate of $0.50/kWh as that is public information (source www.pge.com). For consistency, PG&E used the same rate in 2018.

Benefit Category: Technology Adoption and Customer Engagement – ADR incentivizes customers for adopting new 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. An overview of associated benefits are provided below:

1. Cumulative kWh benefit from CBP and PDP: 510 megawatt-hours (MWh)
    a. PG&E does not have information on Demand Response Auction Mechanism (DRAM) and does not include XSP customers for this breakdown.
    b. The MWh value is noticeably down (reduced by about 65%) as PG&E experienced only 2 events in May/June 2018 compared to 7 events called in May/June 2017. The events called in 2018 have also been in targeted sublaps for short time windows so not many ADR customers have been called to participate.
    c. Former Smart Grid Reports detailed benefits that included the Aggregator Managed Portfolio (AMP) and DBP programs, which were closed in 2016. Customers were moved to DRAM, resulting in a reduction in customers enrolled in a CBP/PDP program.
2. GHG Benefit with the 2015 factor from PG&E of 405 lbs of CO_2 per MWh: 206,550
3. Financial benefit based on DBP rates: $255,140

Smart Thermostat Study	Approximate Cost Over Reporting Period: $55 Thousand
Description: PG&E conducted 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 were 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 was 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: In December 2016, a report providing an analysis of the first year's results was posted to the Emerging Technologies Coordinating Council (ETCC) website (https://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. The project's second year of monitoring concluded in the fall of 2017 and a report detailing an analysis of the second year's performance and the results of a survey of the study participants was posted to the ETCC site in March 2018 (https://www.etcc-ca.com/reports/smart-thermostat-study). The results indicate that savings persisted in the second year, although at a somewhat lower level. The consultant concluded that the lower level of savings was due in part to the extreme heat in the second year of the study, and that continuing the study for a second year led to sample attrition making the savings more difficult to detect. Upcoming Plans (Subject to Change): PG&E is expanding upon the Smart Thermostat study to extrapolate energy savings across all climate zones in California to inform savings estimates in the various climate zones. A separate report will be published in Q4 2018 on http://www.calmac.org/. PG&E may also enlist participating smart thermostat study participants to participate in future research. 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.	

3.5. 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 EPIC demonstration projects to further distribution capabilities.

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2017 through June 30, 2018 timeframe, unless otherwise noted.

Advanced Distribution Management System (ADMS)	**Approximate Cost Over Reporting Period:** **$1.95 Million**
Description: This project is the first component of a multi-year effort to implement an ADMS, which will integrate several mission critical distribution control center applications that are currently spread across multiple platforms. The ADMS will become part of the core distribution operations technology tools that enable the visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, Distribution Management System (DMS), and Outage Management System (OMS) into a single platform. These applications are described below. D-SCADA: PG&Es D-SCADA system gathers, processes, and displays system-wide operating data to Distribution Operators at control centers. Operators use the system to remotely control and/or operate devices on the distribution network. The D-SCADA system consists of distributed IT network system and server hardware (the SCADA "platform") and a growing number of SCADA-enabled field devices which send and receive real time data over the network. PG&E's SCADA platform is no longer adequate to support projected growth, evolving cybersecurity threats, or the need for increasing integration with other control center systems. RT-SCADA, the current application managing data exchange between field devices, processors/servers, and displays in the control center, is nearing the end of its useful life and does not have the functionality and cybersecurity features to address future grid conditions, including an increased number of field devices and increased DER penetration. Similarly, the current hardware supporting the SCADA system does not have sufficient processing or storage capacity to address the increasing complexity of the grid, or to support advanced control applications that will be available if the platform is upgraded. A major part of the project is associated with replacing the hardware and software associated with PG&E's D-SCADA platform, migrating data from the existing D-SCADA database to the new ADMS-SCADA database, and programming and testing to ensure that field devices communicate accurately with the ADMS-SCADA application.[15]	

15 Funding for SCADA replacement and DMS integration was approved in the 2017 GRC. The replacement was scheduled to begin in 2017, and was forecast to be completed in 2021. As further explained below, the start date of the project was pushed back to 2018, and PG&E now forecasts that it will be completed in 2022.

Advanced Distribution Management System (ADMS)	Approximate Cost Over Reporting Period: $1.95 Million

DMS: DMS is a system that utilities use to maintain an As-Operated model of the electric distribution grid, can run applications that analyze and control the grid.

OMS: OMS is a network model-based system that utilities use to identify electrical outage locations and assist in the restoration of power. This system also provides utility customers with updated outage information and is the source for reliability reporting. The accuracy of OMS's identification of outage is dependent on its network model reflecting the actual as-switched state of the distribution system at any given time.

Integrating SCADA, DMS, and OMS into a single, more robust platform will reduce the potential for operator error, improve cybersecurity risk controls, and enable PG&E to run a new suite of advanced applications that enhance current capabilities associated with safety, reliability, and affordability, and respond to future needs associated with the growth of DERs and complexity from growing wildfire risk.

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

Status: ADMS is in the Plan/Analyze stage. PG&E conducted a RFP to evaluate the ADMS software vendor marketplace in 2018 and (as of July 2018) is developing an implementation contract with the chosen vendor.

Upcoming Plans (Subject to Change): PG&E expects to complete the Design phase in mid-2019, and subsequently enter the Build phase.

Benefits Description: ADMS delivers the following benefits:

- Safety – Address the known cyber security vulnerabilities of the existing D-SCADA application.
- Situational Awareness
    - ADMS can estimate the behind the meter load served by DERs, showing operators, the total load consumed. This load estimation, coupled with some real-time telemetry of DERs, can provide operators with estimates that provide actionable information to perform restoration in the event of an outage on a circuit with a high penetration of DERs.
    - ADMS can automatically filter and prioritize alarms for operators, making the operator more efficient when evaluating and addressing grid issues. This is especially important when storms create well above average outage and alarm volume, and operators can be inundated with alarms.
    - ADMS will promote greater awareness of real-time grid status by enabling sharing of information contained in the ADMS with wider audiences across utilities. In addition, PG&E looks to "mobilize" ADMS features and allow for more PG&E personnel to have access.
- Training – ADMS has a training simulator that can effectively train existing and new operators. The simulator allows the creation of real-life complex training scenarios that includes SCADA related events and operations, switching management, outage management events (e.g., customer calls, SmartMeter outage notifications, hazards, damage, etc.).

Advanced Distribution Management System (ADMS)	Approximate Cost Over Reporting Period: $1.95 Million

- Operational Efficiency
    - ADMS enables switching submittal, planning, and execution to be a process contained within one application, driving substantial efficiency. ADMS provides the ability for efficient scheduling with “clash checking” as well as fast development of switch logs, with fully embedded intelligence to verify the switch log’s impact, in both real time and study mode.
    - Better load forecasting driving better grid operations: ADMS has a load forecasting engine that develops “operational time horizon” (i.e., 24 hr., 7 day) load forecasts.
    - FLISR expansion and maintenance: FLISR is an advanced application that is part of the ADMS platform. ADMS FLISR will know the topology and capacity of the grid, and the forecasted load. Therefore, ADMS FLISR requires less time to configure than PG&E’s existing FLISR, which as a standalone application must manually be configured.
    - Reduce utility line losses: ADMS’s optimal power flow capabilities can control SCADA-enabled capacitors to minimizing line losses while maintaining power factor and voltage compliance. Reducing line losses lowers GHG emissions and reduces PG&E’s energy procurement costs.
    - Drive Conservation Voltage Reduction (CVR): ADMS’s optimal power flow capabilities can control SCADA-enabled substation transformer load tap changers, line voltage regulators, and capacitors to drive CVR. CVR is a physical effect which reduces the energy consumed by customers’ devices. This lowers GHG emissions and reduces PG&E’s energy procurement costs.

Benefit Category: Smart Utility

Distribution Substation Supervisory Control and Data Acquisition (SCADA) Program	Approximate Cost Over Reporting Period: $44.8 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 560 substations and approximately 1,930 breakers.

Funding Source: 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 432 substations and 1,670 breakers between 2011 through June 2018.

Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve 100% visibility and control by 2019 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets. 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 Project	**For More Information on EPIC Pilots, Refer to 'Electric Program Investment Charge (EPIC) Program' Box**
Description: PG&E utilizes EPIC Projects in 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 – Closed; details in Appendix) and using energy storage to mitigate overload conditions on substation equipment (EPIC 1.02). EPIC 1.02 Energy Storage for Distribution Operations project demonstrated the ability of a utility-owned and controlled energy storage resource to deliver autonomous distribution peak shaving functionality. Energy storage resources hold significant promise to help California address a variety of grid planning and operations challenges, both today and in the future, and can be used to provide more reliable and clean power to customers for lower overall costs. The learnings from this project can help inform utility procurement and operation of future energy storage resources, both utility-owned and utility-contracted, through compliance with the IOU energy procurement targets as set forth in CPUC and beyond. Funding Source: EPIC Project 1.02 is funded through EPIC. Status: EPIC 1.02 completed successfully in 2017. Since this project was successfully completed, PG&E has been using learnings from this project to inform utility procurement process and operation of future energy storage resources. Upcoming Plans (Subject to Change): • Maintain and improve the autonomous bank load management control scheme as a platform for automating the response of current and future PG&E battery storage resources • Investigate future demonstration applications of Browns Valley Battery Energy Storage System, such as phase balancing • Evaluate with other Energy Storage approaches to help shape Energy Storage strategy conversations both within California and the larger industry Benefit Description: EPIC 1.02 demonstrated the ability to use energy storage to perform multiple applications by the same storage system. This could maintain or improve reliability, reduce pressures on customer rates, and provide services into new or expanded CAISO and utility markets. It demonstrates a new market for energy storage systems and could support the economic development of new storage companies in California. Energy storage resources hold significant promise to help California address a variety of renewable integration challenges, both today and in the future. The implementation and	

operational challenges associated with EPIC 1.02 project resulted in learnings that will inform PG&E's procurement of future energy storage resources, both utility-owned and utility-contracted, through compliance with the IOU energy procurement targets as set forth in CPUC D.10-03-040 and beyond. This project prepares PG&E to better understand the financial performance to assess cost-effectiveness valuations of future battery storage procurements, the interconnection process to deploy battery assets, and operating experience using enhanced control capabilities. These results have the potential to be leveraged by other electric utilities. 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:** **$6.7 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. Upcoming Plans (Subject to Change): The Smart Grid FLISR project 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.	

3.6. 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, 2017 through June 30, 2018 time period, unless otherwise noted.

Transmission Substation SCADA Program	**Approximate Cost Over Reporting Period:** **$16.9 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 465 substations and approximately 1,760 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 400 substations and 1,645 breakers from 2011 through June 2018. Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve 100% visibility and control by 2019 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets. 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:** **$42.3 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 which doesn't have a defined end date. The project began in 2005. PG&E has installed and completed 112 MPAC buildings. Upcoming Plans (Subject to Change): The MPAC program will continue focusing on deploying pre-engineered, fabricated, and standardized control buildings in transmission substations to support other capital projects in an integrated manner, such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.	

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 $2.6 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $464.6million.[16] Benefit Category: The program is a Smart Utility project designed to improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities.

Energy Management System (EMS)	Approximate Cost Over Reporting Period: $4.3 Million
Description: The EMS system is utilized by Transmission System Operations (TSO) to monitor and control the transmission system. The system is comprised of several modules which provide different functionality to Operations personnel. PG&E has determined that the hardware platform for the existing Energy Management System (EMS) and related software systems needs to be updated to accommodate system expansion, add new functionality to required meet NERC compliance requirements and reduce risk of failure due to the age of the hardware. Funding Source: This project is funded primarily under PG&E's TO cases. Status: Active. The current date for the cutover to the new systems is 10/2018. The new hardware has been deployed and the final software delivery will occur mid-August 2018. Final testing will occur through mid-September. User training will start mid-September 2018 through cutover in October 2018. Upcoming Plans (Subject to Change): refer to Status above. Benefit Description: The new EMS will include new hardware and software functionality to meet NERC Standards and provide enhanced functionality for the monitoring and control of the PG&E transmission system. Benefits include: • Allows for the retirement of the Primate application and hardware. This reduces the work required to maintain an additional system. It also simplifies the user experience. • Adds the ability to interface with the transmission outage application to allow for more accurate studies of system conditions. • Provides a more flexible system architecture which allows for easier and less costly system updates. • Adds several new applications to enhance the ability of system operators and dispatchers to better monitor and control the transmission system. Benefit Category: System Reliability and Operational Efficiency	

16 MPAC benefit totals reflect updated calculations for 2018 Smart Grid Annual Report.

Synchrophasor Project Realization	Approximate Cost Over Reporting Period: $0.8 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 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 TSO 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 continuing to support data availability and data quality. Synchrophasor test lab completed. Working with PeakRC, CAISO, Bonneville Power Administration, and SCE to improve Synchrophasor data sharing capability. Working with CAISO to install Phasor Measurement Units (PMU) on all tie-lines with external BAs (Balancing Authorities) to better monitor frequency response to grid disturbances. Establishing a synchrophasor data archive to enable enterprise wide access to synchrophasor data.

Upcoming Plans (Subject to Change):

- Install PMUs on all 500 kilovolt buses for enhanced state estimation
- Install PMUs on tie-lines with other adjacent BAs to enable the CAISO to quantify frequency response per the requirements of NERC BAL-003
- Establish data stream to the Utility Data Network corporate network to enable PI data archival and other enterprise applications

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 TOs and reliability coordinators

Benefit Category: System Reliability and Operational Efficiency

3.7. 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, 2017 through June 30, 2018 time period, unless otherwise noted.

Network Supervisory Control and Data Acquisition (SCADA) Monitoring Project	**Approximate Cost Over Reporting Period:** **$9.3 Million**
Description: 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 DG 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. Funding Source: This project is funded by PG&E's 2014 and 2017 GRC filings and requests to be filed in the 2020 GRC. Status: 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, and Y-1) in progress. These completed network groups have been added to the PI Historian system which is the data accumulator for all 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. Upcoming Plans (Subject to Change): Continue with this project with installation of approximately one network group per year. Planned overall completion by 2024. Benefit Description: The new control features included as part of this project will improve personnel safety and overall system operability.	

Benefit Category: Smart Utility – This project provides information for PG&E to better manage its assets and make informed maintenance, repair and upgrade decisions.

3.8. 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 program, the Identity and Access Management (IAM) program. This is a multi-year investment focused on improving PG&E's core access control capabilities. Additional detail on this program 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 (Sarbanes-Oxley (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: $5.56 Million**
Description: The IAM Program is a multi-year, multi-project enterprise level investment that strengthens authorized PG&E system access controls and reduce the risk of unauthorized access. The program improves 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 provides enhanced auditing capabilities to achieve enterprise wide visibility and control of employee access to systems. Through the IAM Program, PG&E continues to 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. Upcoming Plans (Subject to Change): The program is currently deploying several enhancements and expansions throughout the enterprise to extend and augment existing technologies for access management. One current focus is on deployment of	

robotic process automation to simplify integrations of applications for regular access recertification tasks, which will allow the IAM team to provide multiple lower cost options for applications to add IAM services. This includes the ability to require training prior to provisioning of entitlements. These improvements will allow the IAM program to move integration activities from an internal project-based practice to an operations and service based practice. Future work will focus on further automation and controls to reduce the cost of ownership.

Benefit Description: As of July 2018, 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 hundreds of 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 MyAccess for both physical and logical 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, strengthen controls for shared administrative and service accounts, and increase efficiency and effectiveness of re-certification tasks.

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.

3.9. 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, 2017 through June 30, 2018 time period, unless otherwise noted.

Telecommunications Architecture	**Approximate Cost Over Reporting Period:** **$1.035 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 continues to be enhanced to facilitate increased communications and be 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, PMUs, 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: The Multi-Protocol Labels Switching (MPLS) project completed in July of 2017 as anticipated. This completes the migration of the core of our network to a multi-service, multi-platform network. We are continuing to consolidate the IP network edge to further reduce the devices in the IP network and bring the multi-service, multi-platform capability to the edge of the network. Migration off of legacy Time Division Multiplexing based lease services has been halted in the field while testing is performed to validate that IP based services from Telephone Service Providers are capable of delivering critical PG&E applications, and meeting service level requirements. Wireless edge technologies have moved out of pilot stage and into full production.

Upcoming Plans (Subject to Change): PG&E will continue to consolidate remaining core and edge network technologies onto the MPLS and FAN (field area network) to further reduce the device count in our networks which enhances functionality, manageability as well as security. This action is foundational in nature and targeted to meet the anticipated growth in grid devices (PG&E and DERs) which are on the rise in an accelerated fashion. These grid devices will be enabling higher resolution of grid performance and enhanced application to manage DERs, automation programs and support the Wildfire Safety Program.

Benefits Description: No hard benefits have been estimated for this project. As a result of successfully completing the MPLS project, PG&E has forecast soft benefits (or avoided costs) by reducing the number of routers required for asset lifecycle/replacement and their corresponding SmartNet licenses.

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, SCE, SDG&E, 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 the effects of a Ukraine-style cyberattack on the California grid, and the development of a representation of a PG&E substation for higher-fidelity testing at Idaho National Laboratory.
- The Grid Integration Flexibility Metrics project has been completed It is socialized the results of its modeling through the stakeholders of the Commission's Integrated Resource Planning 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: $16.6 Million**

Description: The EPIC program provides funding to cost-effectively develop and demonstrate promising new technologies which can advance the company's core values of Safety, Reliability, and Affordability 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): On November 19, 2013, the CPUC issued D.13-11-025, which authorized the first triennial investment period of 2012-2014 (referred to as EPIC 1).
- EPIC 2 (2015-2017): On April 15, 2015, the CPUC issued D.15 04 020, which approved the second triennial investment plan period of 2015 2017 (referred to as EPIC 2). PG&E's EPIC 2 application included 30 potential projects. On August 10, 2017, the CPUC issued Res. E-4863, which approved two of the six new EPIC projects proposed by PG&E via a Tier 3 AL 5015-E filed on February 7, 2017, between triennial EPIC Applications as permitted by D.15-09-005.
- EPIC 3 (2018-2020): On April 28, 2017, PG&E filed its A.17-04-028 for the third triennial investment plan period of 2018-2020 (referred to as EPIC 3). PG&E's EPIC 3 application includes 41 potential projects.

For more information on the CPUC EPIC decisions please visit www.pge.com/epic.

Project status: Information about PG&E's EPIC projects can be found in PG&E's EPIC 2017 Annual Report, which was filed on February 28, 2018, and can be found on PG&E's website at www.pge.com/epic. All final reports for projects that are complete are publicly available at the same site.

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $16.6 Million

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, commensurate with the average change in the Consumer Price Index, and this adjustment will occur again. 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: costs reflected in this report reflect PG&E expended costs over the reporting period of July 2017 – June 30,2018. No CEC funds are included.

Status: Through the course of the reporting period, PG&E's EPIC 1 and 2 Programs made significant progress and achieved noteworthy successes on many of the projects. Of the thirty-six projects started across EPIC 1 and EPIC 2, a total of twenty-two EPIC projects have completed. Seven of these twenty-two projects completed within this reporting period, which included one EPIC 1 project and six EPICS 2.

Projects completed during the reporting period can be found in the appendix. Upon completion of these projects, PG&E will leverage learnings and may operationalize associated results, where applicable and cost-effective. T he results of PG&E's technology demonstrations are also highly applicable to other industry stakeholders. For example, 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.

In 2018, PG&E will continue to execute in-progress projects, including one EPIC 1 project and thirteen EPIC 2 projects. PG&E also plans to start execution on EPIC 3 projects subject to the timing of CPUC's approval of PG&E's EPIC 3 Application for the 2018-2020 program cycle.

EPIC 1

In the first triennial cycle, the EPIC 1 portfolio demonstrated PG&E's ability to adopt a new model for managing, aligning, tracking and executing RD&D activities. This portfolio covered a wide spectrum of technologies that help make the electric grid safer, more reliable and more affordable for customers. Some notable examples of EPIC 1 achievements in the reporting period include:

- *EPIC 1.01 – Energy Storage End Uses:* This project successfully utilized PG&E's Vaca-Dixon and Yerba Buena BESS to gain experience that addresses multiple barriers for utility-scale battery storage systems to participate in the CAISO's Non-Generator Resource (NGR) market. PG&E developed and deployed an automated communications and control solution to fully utilize and evaluate BESS fast-response functionalities to determine their ability to instantaneously switch between different market products as the price of those products change. The project established input to processes for the operation of utility-scale battery storage resources as both market and distribution system assets, which may improve reliability and advance resilience by supporting PG&E customers in the event of a disturbance or outage. These results have the potential to be leveraged by other electric utilities. The Association of Edison Illuminating Companies (AEIC) recognized and awarded PG&E the 2017 AEIC

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $16.6 Million

Achievement Award for EPIC Project 1.01. The award was granted in recognition of the significant contribution that work on this project has made toward advancing electric energy industry operations.

- *EPIC 1.02 – Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction:* This project demonstrated the ability of utility-owned and controlled energy storage resources to deliver autonomous distribution peak shaving functionality. Energy storage resources hold significant promise to help California address a variety of grid planning and operations challenges, both today and in the future. Energy storage resources have potential to advance GHG reduction goals and provide lower peak demand power costs for utility customers. The implementation and operational challenges associated with this project resulted in learnings that will inform PG&E's procurement of future energy storage resources for grid support needs, both utility-owned and utility-contracted, through compliance with the IOU energy procurement targets as set forth in CPUC D.10-03-040 and beyond.

EPIC 2

The projects from EPIC 2 are even more focused on long-term strategic objectives and in many cases, are built on the foundation of previous technology investments. Additionally, in EPIC 2, PG&E further explored opportunities to leverage synergies between projects with similar objectives to drive the maximum benefit from the overall technology demonstration at the lowest possible cost to customers. As an example, when feasible, this approach can include sharing resources while also exploring the integration challenges of how the technologies may interact, which will become increasingly important in the future high-DER connected grid. Some project-specific notable examples of EPIC 2 achievements in 2017 include:

- *EPIC 2.02 – Pilot Distributed Energy Resource Management Systems (DERMS):* The DERMS project successfully developed and deployed a cutting edge DERMS on three distribution feeders in San Jose and has been demonstrating seven use cases related to the impact and functionality of DERMS, including situational awareness about DER grid impacts, optimal dispatch of DERs to provide distribution services, and dual-use of DERs to provide distribution devices and enable market participation. Early results validate potential for DERs to provide distribution services and identify key DER requirements and utility investments in grid technology necessary to enable successful communications and dispatch instructions between the grid operator and DERs. Preliminary findings of the project indicate that DERs can successfully provide distribution services both voltage support and grid capacity; however, market participation of large DERs providing regulation complicates online power flow calculations and load forecasting efforts and will need to be addressed as market participation of DERs increases. As the dynamic, two-way operating environment develops, the DERMS project enables PG&E and other utilities to improve electric reliability and equip customers with valuable services and products that support their choices to

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $16.6 Million

adopt clean energy. In 2017, this project received the Greentech Media (GTM) Grid Edge Award[17] and the Metering and Smart Energy International (MSEI) Innovation of the Year Award.[18]

- *EPIC 2.23 – Integrate Demand Side Approaches into Utility Planning:* This project successfully developed and demonstrated how a utility could integrate a broader range of customer-side technologies and DER approaches into the utility planning process. The project served as a necessary and enabling precursor to the fulfillment of Public Utilities Code 769, which requires transparent, consistent and more accurate methods to cost-effectively integrate DERs into the distribution planning process. This project delivered new and more granular load shape profiles and enhanced load forecasting tools and overall analytical processes to allow PG&E to more accurately and consistently integrate DER impact into the distribution system load profile. With these enhancements, PG&E can more effectively assess the impact of DER growth on the timing and need for future distribution and transmission system upgrades. Any deferral of future distribution or transmission system upgrades would lower costs for electric ratepayers.

Some of PG&E's achievements in EPIC 1 and 2 have also enabled PG&E to file four full patents and one provisional patent to date:

- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for the development of the Smart Pole Meter
- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for the development of the Smart Pole Meter Socket
- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities*: Patent for an algorithm to help identify downed wires
- *EPIC 1.21 – Pilot Methods for Automatic Identification of Distributed Energy Resources (Such as Solar PV) as They Interconnect to the Grid to Improve Safety & Reliability*: Patent for an algorithm which can detect unauthorized PV interconnections
- *EPIC 2.29 – Mobile Meter Applications*: Provisional patent for the multi-purpose mobile meter (Next Generation Meter – NGM).

17 GTM has presented the Grid Edge Award for the past 4 years to the leading companies and projects that incorporate DERs and are re-envisioning the concept of centralized, unidirectional electricity delivery and overall addressing electricity management and delivery of the future. For 2017, the submission set was expanded to include international projects and companies, as well.

18 The MSEI award focuses on projects demonstrating the use of cutting-edge technology and critical thinking that are advancing utility systems into the 21st century.

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $16.6 Million

These patents may provide potential future revenue generating opportunities that would be shared with PG&E's customers and shareholders,[19] and ultimately support improved affordability if the patents lead to increased revenue. PG&E continues to consider opportunities to license patents, as well as opportunities to identify additional IP in these and other projects.

Through the EPIC projects, PG&E has collaborated with national laboratories, universities, other utilities, third-parties, etc. Examples of collaboration include:

- *EPIC 1.02 – Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction:* Early drafts of the BESS test protocols used in EPIC Project 1.02 were shared with the Electric Power Research Institute (EPRI) Energy Storage Integration Council and helped form the foundation for the now released EPRI Energy Storage Test Manual
- *EPIC 1.22 – Demonstrate Subtractive Billing with Submetering for EVs to Increase Customer Billing Flexibility*: In this project the joint IOU Administrators (PG&E, SDG&E and SCE) worked together to execute the project with the overall goal that various submetering scenarios be tested and integrated with the different IOU billing systems. Additionally, the project works with multiple EV Meter Data Management Agents to test additional business models for submetering customer EV bills.
- *EPIC 2.05 – Inertia Response Emulation for DG Impact Improvement*: This project is currently working with the National Renewable Energy Laboratory (NREL) on equipment and hardware testing of inertia response. NREL is working with PG&E to develop recommendations on future synthetic inertia equipment performance requirements. NREL's unique ability to test equipment aligned well with the goals of this project to demonstrate the capability to emulate inertia injection and support primary frequency control using energy storage and SI technologies to potentially mitigate the impacts of large-scale DG to the grid.
- *EPIC 2.29 – Mobile Meter Applications:* The project worked with LLNL who provided technical support for product development and demonstration of the mobile meter prototype.

In addition to the achievements highlighted above, it is equally important to recognize the value of EPIC in determining that a project is not ready to scale. The results of a number of EPIC projects found that more data, analysis, or technology advancement is necessary before the technology demonstrated is considered for adoption on a larger scale, which ultimately supports affordability for customers by not adopting the technology at scale before refinements are made to make the technology more viable.

19 The revenue sharing mechanism is based on the guidance provided in CPUC D.13-110-25 OP 34, which states "(IOUs) must apply a 75 percent/25 percent (ratepayer/shareholder) revenue sharing mechanism for net revenues (from future or ongoing r60-62oyalties, license fees, and other "financial benefits of Intellectual Property (IP)") related to financial benefits of IP that was developed under investor-owned utility contracts with Electric Program Investment Charge funds."

Electric Program Investment Charge (EPIC) Program	Approximate Cost Over Reporting Period: $16.6 Million

Next Steps for EPIC Investment Plan

PG&E, in conjunction with the other EPIC Administrators, will continue to host stakeholder workshops in 2018. These industry events will continue to focus on the sharing of progress, results, and future plans, improving coordination and understanding among the various stakeholders in the EPIC Program while raising awareness and visibility of EPIC investments and promoting program transparency. PG&E will also continue to promote the EPIC Program through participation in both internal and external public forums and other industry events.

Technology innovation programs like EPIC are critical to continued advancement of the grid, both to enable increased customer choice and further California's clean energy objectives as well as to increase safety and resiliency in light of climate change. Never has there been a time where innovation plays a more critical role to the future of our grid, and we need to act quickly to meet these opportunities head on. PG&E is excited to embark on new technology demonstrations which can help keep continuity on past projects, meet emerging grid needs and California policy objectives, and ensure that the customers and the state can leverage the maximum benefit of this program.

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 reference, the definition for Diverse Supplier includes: Small Business Enterprises); Women, Minority and Disabled Veteran Business Enterprises; and Lesbian, Gay, Bisexual, and Transgender Business Enterprises. Qualifying vendors must be certified by the CPUC Clearinghouse as follows:

- Small Business Enterprises must be registered as a small business with a state or federal agency (e.g., California Department of General Services or Small Business Administration);
- Women- and minority-owned businesses must be certified by the CPUC's Supplier Clearinghouse;
- Service disabled veteran-owned businesses must be certified by the California Department of General Services; and
- Lesbian, gay, bisexual and transgender-owned businesses must be certified by the National Gay and Lesbian Chamber of Commerce (NGLCC®).

As part of the 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 University of California, Los Angeles 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.

3.10. 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.[20]

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.

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	2019 DRAFT
Energy Management Enablement Tools:						
PG&E Online Account Web Tools	X	X	X	X	X	X
Universal Audit Tools (UAT)	X	X	X	X	X	X
Energy Usage Alerts	X	X	X	X	X	X
Home Energy Reports	X	X	X	X	X***	X***
Third-Party Customer Data Access Tools (e.g., Share My Data, Customer Data Access)	X	X	X	X	X	X
Electric Program Investment Charge**				X	X	X
Behind-the-Meter (Customer Premise) Devices:						
SmartAC*	X	X	X	X	X	X
Distributed Generation (Solar Water Heating, Solar PV, etc.)	X	X	X	X	X	X
HAN; Local Area Network; Smart Thermostat, etc.	X	X	X	X		X

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

Electric Vehicle Supply Equipment*	X	X	X	X	X	X
Rates Options:						
SmartRate and Related Residential Time Varying Rates*	X	X	X	X	X	X
Time-of-Use	X	X	X	X	X	X
Peak Day Pricing	X	X	X	X	X	X
Electric Vehicle Rates	X	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 demonstration projects have some component of customer outreach/marketing. *** Home Energy Reports Only						

3.11. Overview of Customer Engagement Plan

PG&E 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. 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 the goals of each program.

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

- 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, SMS and by mail.

3.12. 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 customers about tools 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. • Leverage new automation capabilities and retargeting with customer who show interest in tools or abandon during the engagement process. • Demonstrate available energy savings by highlighting customer case studies and relevant syndicated or internally developed content. • Ongoing, frequent customer communication through the Small Business and residential digital newsletters.

Enablement Tool: Behind the Meter (Customer Premises) Devices*	
Project Description	ME&O to educate customers about available home or businesses devices that: 1) Stream My Data - This is a service offered to all PG&E SmartMeter customers to connect a HAN or gateway device for real-time meter data access. 2) Allow customers to participate directly in grid operations with tools like SmartAC. 3) Facilitate DERs.

Target Audience	Residential and SMB customers.
Sample Message	"Save energy and money by providing real-time electricity data through an energy-monitoring device."
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 information about devices, focusing on:
	  ○ The benefits and energy management.
	  ○ 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, rates lack differentiation from a customer's perspective. • Lack of customer understanding about why TOU rates are important to the utility/environment in a default scenario, leads to anxiety and dissatisfaction from some customers. • TOU and critical peak pricing requires action from the customer during peak hours or on event days; the utility perspective of peak hours may not align with all customer segments. • Late hours of TOU rate are significant barrier for many residential customers.

Strategy to Overcome Roadblocks	• Sustained, ongoing outreach about default rates for both Residential and SMB (prior to and after default), including context for why rates are important to the utility and environment, as well as providing information on bill protection are critical to success of default TOU. • Encourage participation 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. o 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. o 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. Emphasize that small shifts in energy can make a difference on TOU rate plans.

* 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

3.13. 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.

3.14. 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.

3.14.1. 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.

3.15. 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 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.

3.16. 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 4

SMART GRID METRICS AND GOALS

4. 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 AMI, per CPUC request.

4.1. 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	82 meters
Percentage of Total Meters	0.00152%
Note: Reporting date: July 1, 2017 through June 30, 2018	

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

Other Advanced Meter Malfunctions Metrics	
Metric	Value
a. Number of SmartMeter Devices Installed	5,397,563
b. Number of Smart Meter™ Devices Activated	5,387,857
c. Number of Opt-Outs	47,967
d. Amount of non-SmartMeter Devices and/or Amount of Meters Still Manually Read	91,272
Notes: Cumulative counts as of end of June 2018. The count of meters still manually read includes Opt-Out meters. The cumulative reporting method is consistent with how PG&E reports SmartMeter status in the annual 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 the Winter Peak Due to Smart Grid-enabled, Utility Administered Demand Response (in total and by customer class) – Automated Demand Response Program	
Metric	Value
From the Summer Peak (May 2017 – October 2017)	
Residential*	0 MW
Non-Residential < 200 kW	4.25 MW
Non-Residential ≥ 200 kW	5.75 MW
Other (Agricultural)	1.5 MW
From the Winter Peak (November 2017 – April 2018)**	
Residential	0 MW
Non-Residential < 200 kW	0 MW
Non-Residential ≥ 200 kW	0 MW
Other (Agricultural)	0 MW
Note: The MW values are the average kW shed across all of the events in 2017 on a per Service Account Identification (SAID) basis and then summed. Therefore, this is not the cumulative MW load impact but the average load impact that could be expected on a per event basis. The Non-Residential <200 was determined on an SAID basis the average baseline kW for each event and if that average baseline across the events was <200 it was included in that sum. *The ADR Res program was launched only in October of 2017 and Ecobee was the only smart thermostat that was eligible as it is Energy Star device and OpenADR certified. In 2018, ADR has expanded the incentive offering to Non-Energy Star devices too and has added CBP Res to its list of eligible programs; PG&E anticipates greater customer adoption beginning 2019. **DR programs eligible for ADR are active over the timeframe of May-October.	

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

Percentage of PG&E Demand Response Enabled by ADR in Each Individual DR Impact Program (2017)	
Metric	Value
Percentage of DR enabled by ADR –PDP Program	8.8%
Percentage of DR enabled by ADR –CBP	37%
Note: Percentage represents the Verified kW load reductions (engineering analysis) available for DR programs in 2017, divided by total DR portfolio kW, with the resulting number multiplied by 100. This table is not referencing cumulative load shed across the 2017 DR season. *DBP and AMP are no longer DR programs. These programs are excluded from this table.	

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	4994	<1%
Non-Residential < 200 kW	93	<1%
Non-Residential ≥ 200 kW	5	<1%
Other	0	0%
Total	5092	<1%
CARE	0	0%
Non-CARE	5092	<1%
Total (CARE and Non-CARE)	5092	<1%
Climate Zone P	105	<1%
Climate Zone Q	26	<1%
Climate Zone R	190	<1%
Climate Zone S	490	<1%
Climate Zone T	1159	<1%
Climate Zone V	20	<1%
Climate Zone W	64	<1%
Climate Zone X	3014	<1%
Climate Zone Y	20	<1%
Climate Zone Z	4	<1%
Total by Climate Zone	5092	<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	483,208	10%
Non-Residential < 200 kW	535,766	79%
Non-Residential ≥ 200 kW	9,796	1%
Total	1,028,770	19%
CARE	68,669	6%
Non-CARE	960,101	22%
Total (CARE and Non-CARE)	1,028,770	19%
Climate Zone P	37,873	20%
Climate Zone Q	1,158	30%
Climate Zone R	136,163	22%
Climate Zone S	200,681	22%
Climate Zone T	197,310	16%
Climate Zone V	10,977	19%
Climate Zone W	65,416	22%
Climate Zone X	367,169	18%
Climate Zone Y	11,122	17%
Climate Zone Z	901	4%
Total by Climate Zone	1,028,770	19%
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 HAN with Registered Consumer Devices		
Metric	Number	Percentage
Escalated customer complaints related to the accuracy, functioning or installation of advanced meters	12	24%
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. To derive percentages, the number provided is divided by the number of escalated complaints in total for each category, 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 for 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 for One Year, Reported Annually, With an Explanation for the Replacement		
Metric	Number	Percentage
Advanced meters replaced	51,520	0.95%
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 for 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]	3,622	0.07%
Advanced meters tested measuring usage outside the Commission-mandated accuracy bands[b]	18	0.50%
(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 7/1/17 and 6/30/18 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[1]	1,844,775	34%
Customers using a PG&E web-based portal to enroll in PG&E energy information programs	215,790	4.0%
Customers who have authorized PG&E to provide a third-party with energy usage data[2][3]	205,160	3.4%
(1) 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, 2017 through June 30, 2018).		
(2) Total number and percentage provided covers multiple programs.		
(3) Includes Interconnection agreements. For these customers, PG&E authorizes work with a 3rd party on a customer’s behalf – access to energy usage data is not directly authorized.		

4.2. Plug-In Electric Vehicle (PEV) Metric

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

Number of PG&E Residential Customers Enrolled in a Time-Variant Electric Vehicle Tariffs	
Metric	Value
Number of EV-A Customers	45,232 customers
Number of EV-B Customers	349 customers
Number of identified EV owners* on other time-variant tariffs	9,179 customers
Note: Utilities currently have limited ability to determine which customers have EVs, outside of enrollment in EV rate schedules, and participation in EV rebate programs. *Identified EV owners include customers that have applied for and received PG&E's Clean Fuel Rebate. Customers included in this count are on other rates, including E-6, ETOU-A, ETOU-B, or other time-variant tariffs.	

4.3. 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, 2018

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.		

4.4. Grid Operations Metrics

Note for reliability metrics 1 to 4 - Data for all reporting periods are pulled and refreshed from the Integrated Logging and Information System (ILIS) Operations Database, which may have resulted in differences compared to prior year reported values. ILIS is used by Distribution Operators to log outage switching operations (and ancillary information about network state for System Average Interruption Duration Index (SAIDI)/Customer Average Interruption

Duration Index calculations) and other relevant operations data (i.e., equipment out of service, etc.). The data used includes both unplanned and planned outages that were reported on the T&D systems. The historical Major Events determined from each annual study was used.

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 10 major events in the latest time period of July 1, 2017 through June 30, 2018.

PG&E's System Average Interruption Duration Index, Major Events Included and Excluded		
Period	Metric	Value
2017-2018	SAIDI – Major Events Included	229.8
2017-2018	SAIDI – Major Events Excluded	116.5
2016-2017	SAIDI – Major Events Included	267.7
2016-2017	SAIDI – Major Events Excluded	109.4
2015-2016	SAIDI – Major Events Included	136.4
2015-2016	SAIDI – Major Events Excluded	109.8
2014-2015	SAIDI – Major Events Included	174.1
2014-2015	SAIDI – Major Events Excluded	99.7
2013-2014	SAIDI – Major Events Included	123.8
2013-2014	SAIDI – Major Events Excluded	110.6
2012-2013	SAIDI – Major Events Included	160.9
2012-2013	SAIDI – Major Events Excluded	122.2
2011-2012	SAIDI – Major Events Included	171.9
2011-2012	SAIDI – Major Events Excluded	132.0

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 10 major events in the latest time period of July 1, 2017 through June 30, 2018.

PG&E's System Average Interruption Frequency Index Major Events Included and Excluded		
Period	Metric	Value
2017-2018	SAIFI – Major Events Included	1.141
2017-2018	SAIFI – Major Events Excluded	1.005
2016-2017	SAIFI – Major Events Included	1.462
2016-2017	SAIFI – Major Events Excluded	0.959
2015-2016	SAIFI – Major Events Included	1.132
2015-2016	SAIFI – Major Events Excluded	1.002
2014-2015	SAIFI – Major Events Included	1.155
2014-2015	SAIFI – Major Events Excluded	0.884
2013-2014	SAIFI – Major Events Included	1.090
2013-2014	SAIFI – Major Events Excluded	1.038
2012-2013	SAIFI – Major Events Included	1.211
2012-2013	SAIFI – Major Events Excluded	1.067
2011-2012	SAIFI – Major Events Included	1.191
2011-2012	SAIFI – Major Events Excluded	1.097

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 10 major events in the latest time period of July 1, 2017 through June 30, 2018.

PG&E's Momentary Average Interruption Frequency Index Major Events Included/ Major Events Excluded		
Period	Metric	Value
2017-2018	MAIFI – Major Events Included	1.807
2017-2018	MAIFI – Major Events Excluded	1.638
2016-2017	MAIFI – Major Events Included	2.208
2016-2017	MAIFI – Major Events Excluded	1.493
2015-2016	MAIFI – Major Events Included	1.856
2015-2016	MAIFI – Major Events Excluded	1.684
2014-2015	MAIFI – Major Events Included	1.698
2014-2015	MAIFI – Major Events Excluded	1.393
2013-2014	MAIFI – Major Events Included	1.506
2013-2014	MAIFI – Major Events Excluded	1.443
2012-2013	MAIFI – Major Events Included	1.820
2012-2013	MAIFI – Major Events Excluded	1.650
2011-2012	MAIFI – Major Events Included	1.636
2011-2012	MAIFI – Major Events Excluded	1.501

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. There were 10 major events in the latest time period of July 1, 2017 through June 30, 2018.

Number and Percentage of PG&E's Customers Per Year and Circuits Per Year Experiencing Greater Than 12 Sustained Outages Per Year (Major Events excluded)			
Period	Metric	Number	Percentage
2017-2018	Customers Experiencing Greater Than 12 Sustained Outages Per Year	538	0.01%
2017-2018	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	13	0.42%
2016-2017	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,532	0.05%
2016-2017	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	26	0.84%
2015-2016	Customers Experiencing Greater Than 12 Sustained Outages Per Year	1,287	0.02%
2015-2016	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	17	0.55%
2014-2015	Customers Experiencing Greater Than 12 Sustained Outages Per Year	327	0.01%
2014-2015	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2013-2014	Customers Experiencing Greater Than 12 Sustained Outages Per Year	284	0.01%
2013-2014	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2012-2013	Customers Experiencing Greater Than 12 Sustained Outages Per Year	812	0.02%
2012-2013	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	15	0.49%
2011-2012	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,115	0.04%
2011-2012	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	34	1.12%
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 January 1, 2017 through December 31, 2017. Load factors are calculated on a calendar year basis.

PG&E's Load Factors	
Metric	Value
System Load Factor	52.27%
Residential Load Factor	35.14%
Non-Residential < 200 kW Load Factor	Small L&P: 49.32% Medium L&P: 46.61%
Non-Residential ≥ 200 kW Load Factor	Large L&P: 55.09%
Other (Agriculture) Load Factor	46.34%
Note: Until advanced meters are fully deployed for residential, small Commercial and Industrial (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, 2018.

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	63,732	818
SGIP Distributed Generation Facilities	1,346	317
Non-CSI and Non-SGIP Distributed Generation Facilities	306,177	2,990
Totals	371,255	4,125
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 DG as "Customer-owned or operated generating systems that are enrolled with a utility in the Self Generation Incentive Program (SGIP) or the 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 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, 2017 through June 30, 2018.

Year	Month	Approximate Exports*(GWh)
2017	Jul	295.7
2017	Aug	243.2
2017	Sept	229.8
2017	Oct	230.2
2017	Nov	146.5
2017	Dec	158.4
2018	Jan	134.5
2018	Feb	231.8
2018	Mar	275.7
2018	Apr	363.9
2018	May	413.8
2018	Jun	401.5

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.

*Exports listed are approximate and subject to slight variation due to changes to PG&E's internal database structures and rounding.

Metric 8: Number and percentage of distribution circuits equipped with automation or remote-control equipment, including SCADA systems. The measure is for July 1, 2017 through June 30, 2018.

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	3,012	3,165	95.2%
Note: 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 5

APPENDIX

5. Appendix

2018 Smart Grid Annual Report

Approximate Recorded Smart Grid Project Costs from July 1, 2017 Through June 30, 2018[21]

Project Name	7/1/17 to 6/30/18 Approximate Recorded Amount
Customer Engagement and Empowerment Projects	
Supply Side (SSP) / Supply Side II (SSP II) DR Pilot (Continuation of IRM Pilot Phase 2)	$0.63 Million
Excess Supply DR Pilot (XSP)	$0.58 Million
AC Cycling Next Generation Technology Assessment	$7.2 Million
Electric Vehicle Rates	$0.1 Million
Electric Vehicle Infrastructure	$12 Million
Energy Diagnostics and Management	$3.8 Million
Bill Forecast Alerts	$0.024 Million
Share My Data (Customer Data Access) Project	$4.7 Million
Energy Data Access	$0.2 Million
Stream My Data aka Home and Business Area Network (HAN)	$0.44 Million
Building Benchmarking Portal	$0.4 Million
Time Varying Pricing (TVP) Rates	$7.2 Million
Automated Demand Response (ADR) Program	$4.1 Million
Smart Thermostat Study	$0.055 Million
Distribution Automation and Reliability Projects	
Advanced Distribution Management System (ADMS)	$1.95 Million
Distribution Substation Supervisory Control and Data Acquisition (SCADA) Program	$44.8 Million
Battery Energy Storage System (BESS) Demonstration Projects	Refer to EPIC box
Smart Grid Fault Location, Isolation, and Service Restoration (FLISR)	$6.7 Million
Transmission Automation and Reliability Projects	
Transmission Substation SCADA Program	$16.9 Million
Modular Protection Automation and Control (MPAC) Installation Program	$42.3 Million
Synchrophasor Project Realization	$0.8 Million
Energy Management System	$4.3 Million

21 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	7/1/17 to 6/30/18 Approximate Recorded Amount
Asset Management and Operational Efficiency Projects	
Network Supervisory Control and Data Acquisition (SCADA) Monitoring Project	$9.3 Million
Security (Physical and Cyber) Projects	
Identity and Access Management Project	$5.56 Million
Integrated and Cross-cutting Systems Projects	
Telecommunications Architecture	$1.035 Million
California Energy Systems for the 21st Century Program	$4 Million
Electric Program Investment Charge Program	$16.6 Million

Project Name (Closed)	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
Universal Audit Tools (UAT) PG&E provides the Home Energy Checkup and Business Energy Checkup (also known as UATs) 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
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
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
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

Project Name (Closed)	Completion Date
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 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
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
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
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
Demand Response Transmission and Distribution System Integration In T&D System Integration, PG&E evaluated areas where existing and future DR programs can be implemented and designed to support PG&E's T&D planning and operations. 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 SCADA.	April 2017

Project Name (Closed)	Completion Date
Demand Response Plug-In Electric Vehicle (DR PEV) Pilot The DR PEV Pilot demonstrated 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 was 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 required BMW to provide a minimum of 100 kW of capacity at any given time, regardless of how many BMW i3 EVs are charging. Once an event is called, BMW utilized proprietary aggregation software to delay charging of participating customers (via telematics embedded in the vehicle) to reduce load on the grid. The algorithm prioritized 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.	December 2016

Project Name (Closed)	Completion Date
Distribution Automation and Reliability Projects	
Cornerstone Improvement Project – Feeder Automation The Cornerstone Improvement Project includes the installation of distribution feeder 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
Regional Synchrophasor Investment Project As part of this project, PG&E installed or upgraded Synchrophasor technology, also known as PMUs, 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
SmartMeter Outage Management Integration Project The SmartMeter Outage Management Integration project integrates the SmartMeter "Last Gasp" and Restoration messages into PG&E's OMS 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
EPIC 1.01: Energy Storage for Market Operations EPIC 1.01 Energy Storage for Market Operations project successfully utilized PG&E's Vaca-Dixon and Yerba Buena BESSs to gain experience and data by participating in CAISO's NGR market model. PG&E developed and deployed an automated communications and control solution to fully utilize and evaluate BESS fast-response functionalities.	September 2016
Install Smart Grid Line Sensors Pilot The 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	December 2016

Project Name (Closed)	Completion Date
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.	
Voltage and Reactive Power (Volt/Var) Optimization System Pilot 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). Volt-Var Optimization (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. 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.	December 2016
Detect and Locate Faulted Circuit Conditions Pilot 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.	December 2016
Transmission Automation and Reliability Projects	
Compressed Air Energy Storage (CAES) Demonstration Project 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.	2017
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
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
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

Project Name (Closed)	Completion Date
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
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	
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
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

Project Name (Closed)	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